Agenda Date: 11/12/26
Agenda Item: 8A

# STATE OF NEW JERSEY

## Board of Public Utilities

**44 South Clinton Avenue, 1st Floor**
**Trenton, New Jersey 08625-0350**
**www.nj.gov/bpu/**

CLEAN ENERGY

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| IN THE MATTER OF ESTABLISHING THE POWERUP NEW JERSEY PROGRAM | ) | ORDER ESTABLISHING THE POWERUP NJ PROGRAM AND ADOPTING MINIMUM FILING REQUIREMENTS |
| IN THE MATTER OF ADVANCING VIRTUAL POWER PLANT (VPP) PROGRAM IN THE STATE OF NEW JERSEY | ) | |
| IN THE MATTER OF THE GARDEN STATE ENERGY STORAGE PROGRAM – PHASE 2 DISTRIBUTED STORAGE | ) | DOCKET NO. QO26100658<br>DOCKET NO. QO26030099<br>DOCKET NO. QO26040116 |

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BY THE BOARD:

By this Order, the New Jersey Board of Public Utilities ("Board" or "BPU") establishes the **PowerUp NJ Program**, a coordinated suite of demand-side, distributed energy resource ("DER") programs designed to reduce peak demand, mitigate capacity and transmission cost pressures, improve distribution-system flexibility, and provide measurable benefits to New Jersey ratepayers. The PowerUp NJ Program will initially comprise two component programs: the Virtual Power Plant ("VPP") Interim Program and Block 1 of Phase 2 ("Block 1") of the Garden State Energy Storage Program ("GSESP"), which will provide performance-based incentives for eligible residential and small commercial energy storage systems.

By this Decision, the Board also adopts Minimum Filing Requirements ("MFRs") for the State's four electric distribution companies ("EDCs") – Atlantic City Electric Company ("ACE"), Jersey Central Power & Light Company ("JCP&L"), Public Service Electric and Gas Company ("PSE&G"), and Rockland Electric Company ("RECO") – and directs each EDC to file a petition proposing its PowerUp NJ Program consistent with those MFRs no later than February 12, 2027.

VPP Interim subprograms shall be operational by October 1, 2027. Block 1 shall open for enrollment within 60 days of Board approval of each EDC's filing. By this Order, the Board also establishes the cost recovery treatment applicable to the PowerUp NJ Program. The Board finds that conventional cost-of-service treatment, which compensates a utility in proportion to what it spends, is not, by itself, reasonably calculated to maximize the peak demand reductions and verified system benefits that these programs are intended to deliver. Accordingly, although this Order adopts a recovery structure that allows the EDCs to recoup their costs, it also requires Board Staff ("Staff") to evaluate mechanisms for future potential implementation that are better tied to verified system benefits and ratepayer savings than utility expenditure alone.

This Order further provides the technical, market-support, and coordination requirements necessary to begin development of a long-term, open-access VPP framework. These requirements are intended to position New Jersey distributed energy resource ("DER") aggregations ("DERAs") to deliver measurable peak demand reductions in the near term, support future distribution-level grid-flexibility services, and participate competitively in the wholesale markets administered by PJM Interconnection, L.L.C. ("PJM") over the long term where such market participation improves the value stack DERs offers ratepayers.

The Minimum Filing Requirements for the VPP Interim Program are set forth in **Attachment A**.

The Minimum Filing Requirements for Block 1 are set forth in **Attachment B**.

The Staff responses for VPP Straw Proposal comments are set forth in **Attachment C**.

The Staff responses for Block 1 Straw Proposal comments are set forth in **Attachment D**.

The Annual Block 1 Incentive Payment Calculation Example is set forth in **Attachment E**.

The Interim VPP Benefit-Cost Analysis Methodologies and Assumptions are set forth in **Attachment F**.

The Block 1 Benefit-Cost Analysis Methodologies and Assumptions are set forth in **Attachment G**.

The Block 1 Benefit-Cost Analysis is set forth in **Attachment H**.

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# I. BACKGROUND AND PROCEDURAL HISTORY

## A. Executive Order No. 1

On January 20, 2026, Governor Mikie Sherrill issued Executive Order No. 1 ("EO 1"),[1] declaring that the ongoing electricity affordability crisis in New Jersey constitutes a state of emergency and directing the Board to take a series of actions to provide short-term rate relief and to pursue structural reforms that lower electricity costs over the long term. EO 1 found that from June 2023 to June 2025 the average residential electricity price in New Jersey rose by well over 33 percent, and that the average price for all customers, including commercial customers, rose by nearly 30 percent. EO 1 directed the Board to review and revise the Clean Energy Program budget, consider opportunities to reduce the Societal Benefits Charge, and complete a study on modernization of the traditional electric distribution utility business model.

The PowerUp NJ Program established by this Order responds to EO 1's affordability and utility-business-model directives by beginning to shift utility program design toward measured peak-demand reduction, demand flexibility, and verified system benefits. By coordinating the VPP Interim Program with Block 1, this Order establishes a near-term framework for distributed, customer-sited resources to reduce costs for ratepayers, improve utilization of the electric distribution system, and support the development of a more flexible and performance-oriented utility model.

## B. Executive Order No. 2

On the same date, Governor Sherrill issued Executive Order No. 2 ("EO 2"),[2] which incorporated the findings of EO 1 and further declares that rising electricity demand and a shortage of supply in the PJM region have created both an affordability crisis and serious reliability concerns. EO 2 noted that PJM anticipates peak load growth of approximately 20 percent by 2030 compared to 2024 levels, driven overwhelmingly by new large electricity customers such as data centers, and that recent PJM capacity auctions (i.e., Base Residual Auction ["BRA"]) in July and December 2025 each imposed over $2 billion in new annual capacity costs on New Jersey families and businesses. The December 2025 auction failed, for the first time, to procure sufficient capacity to meet PJM's own target level of reserves. EO 2 further noted that the auction's capacity shortfall of 4.5 gigawatts is approximately equivalent to the electricity consumption of nearly all residential households in New Jersey. The subsequent capacity auction conducted in July 2026 once again failed to procure sufficient capacity, causing the regional capacity shortfall to increase to 6.8 gigawatts further highlighting the rapidly growing need to reduce peak energy dem[3]nd across the state.[4]

EO 2 identified multiple obstacles to the development of new centralized generation, including multi-year equipment backlogs for new natural gas-fired turbines and decade-scale development timelines for new nuclear generation, and emphasizes that solar energy and energy storage can often be deployed in a matter of months. EO 2 further found that the availability of technology to

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[1] Exec. Order No. 1 (Jan. 20, 2026), 58 N.J.R. 1039(b) (Feb. 17, 2026).

[2] Exec. Order No. 2 (Jan. 20, 2026), 58 N.J.R. 1041(a) (Feb. 17, 2026).

[4] PJM Interconnection, L.L.C., 2028/2029 Base Residual Auction Report 3 (July 14, 2026), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf.

aggregate behind-the-meter ("BTM") DERs – including rooftop solar paired with energy storage, electric vehicles ("EVs"), and smart home and building controls – into VPPs presents an opportunity to reduce peak demand by an estimated 10 to 20 percent.

EO 2 directed the Board to accelerate development of the GSESP to support deployment of distributed energy storage and improve grid stability. EO 2 further directed the Board to, within 180 days, commence development of a VPP program in New Jersey to be administered by electric distribution utilities and third-party suppliers ("TPS"), for the purpose of driving down peak demand by aggregating BTM DERs; building on and advancing existing peak demand reduction and Energy Efficiency ("EE") programs.[5]

In response to these related directives, this Order establishes the PowerUp NJ Program as a coordinated framework through which the VPP Interim Program and Block 1 can operate as a suite of programs under a single name. The PowerUp NJ Program will support near-term deployment of dispatchable distributed resources, reduce peak demand, mitigate capacity and transmission cost pressures, and create the operational foundation for longer-term VPP and grid-flexibility participation.

## C. FERC Order No. 2222 and PJM Implementation

In September 2020, the Federal Energy Regulatory Commission ("FERC") issued Order No. 2222, requiring all Regional Transmission Organizations and Independent System Operators to revise their tariffs to allow DERs and DERAs to participate directly in wholesale markets. Order No. 2222 addresses structural barriers that previously prevented DER participation, including minimum size thresholds, telemetry and communication requirements, metering standards, and performance obligations designed for central-station generators.

On May 1, 2025, FERC approved PJM's final compliance filing implementing Order No. 2222.[6] PJM must implement tariff changes enabling DERA participation in the energy and ancillary services markets by February 1, 2028, and has enabled DERA participation in the capacity market beginning with the 2028/2029 delivery year BRA. The 2028/2029 BRA was conducted in June 2026 and while PJM noted that[7], there is an increased likelihood of DERA participation in both BRAs and Incremental Auctions once PJM finalizes the necessary tariff revisions throughout 2027. A DERA seeking to participate in the 2029/2030 BRA must have previously submitted a notice of intent to PJM by June 12, 2026; to participate in the 2030/2031 BRA, a DERA must submit a notice of intent by December 1, 2026. PJM's compliance filing also addresses the interface between state-level compensation and wholesale market payments and provides that state-level distribution service payments do not create a barrier to wholesale market participation provided that appropriate protections against double counting of the same underlying capacity service are in place. Because Block 1 will support behind-the-meter storage resources that may later opt out of the GSESP and participate in Order 2222 DERAs, this Order is intended to preserve future compatibility with PJM DERA requirements while protecting against duplicative compensation for the same underlying grid-service value, as described later in this Order.

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[5] EO 2 § 4.

[6] PJM Interconnection, L.L.C., 191 FERC ¶ 61,097 (2025).

[7] PJM Interconnection, L.L.C., 2028/2029 Base Residual Auction Report 4 (July 14, 2026), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf.

# D. Procedural History

## i. Board Engagement of DERAs

The Board's engagement on DERA policy predates EO 2. In March 2024, Staff issued a Request for Information ("RFI") on FERC Order No. 2222 and DERA participation in wholesale markets.[8] Staff received comments from EDCs, non-profit clean energy organizations, developers of DERs and DERA-related technologies, and other State agencies. Staff convened a technical conference in January 2025, which opened with a PJM presentation on its DER Aggregation Participation Model and included panels on DERA registration and administrative processes, technical and infrastructure topics, and implementation costs.[9] Stakeholders indicated that they want the Board to serve as a coordinator for DERA operations and to facilitate development of a DER Registry and a Code of Conduct, and identified core issues including DERA registration, the EDCs' role in the aggregation process, dispute resolution, data access, dispatch override, cost allocation and recovery, cybersecurity, protection against double counting, and affordability and accessibility. These issues also inform the design of Block 1, because residential and small commercial storage resources supported through Block 1 may eventually be enrolled, aggregated, dispatched, measured, verified, compensated, and coordinated with EDC systems in a manner that is consistent with the State's developing VPP framework.

## ii. The Triennium Programs and Demand Response

Under the Triennium framework for EE and peak demand reduction, the EDCs' Triennium 2 portfolios include demand response ("DR") and VPP pilot programs. By Order dated July 15, 2026, the Board approved a one-year Program Year 7 framework and directed the utilities to continue their Triennium 2 DR programs until such time as the VPP Interim Program is operational, at which point the DR pilot programs are to be closed and participants transitioned.[10] The Program Year 7 Order also directed that DR programs and their associated cost recovery move into the VPP Interim Program and authorized the utilities to continue offering cost-effective financial incentives for devices capable of integration into a VPP program.

Through EE and EV programs, the utilities and the Board have paid for a total of 437 MW of DR capacity from smart thermostats (420.0 MW), EV chargers (15.0 MW), and smart water heaters (2.0 MW) that can quickly be integrated into the VPP Program. Staff anticipates that by enrolling 75% of the known devices in each utility territory, for which the EDCs already have contact information, nearly half to more than 80% of the peak shaving goal can be achieved by each utility. The existing device DR capacity data shown in Table 1 is derived from the reports of the

[8] In re New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, Notice of Request for Information, BPU Docket No. EO24020116, Notice dated Mar. 7, 2024.

[9] In re New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, Notice of Technical Conference, BPU Docket No. EO24020116, Notice dated Jan. 7, 2025.

[10] In re Program Year Seven of the Energy Efficiency and Demand Response Programs Implemented Pursuant to the New Jersey Clean Energy Act of 2018, L. 2018, c. 17, BPU Docket No. QO26070382, Order dated July 15, 2026 ("Program Year 7 Order").

number of [11] [12] 1 and 2 and [13] the total number of programs. The reported average load reduction

[11] In re the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis, BPU Docket No. GO18101112 and EO18101113, Order Dated September 23, 2020. Settlement Model; In re the Petition of Atlantic City Electric Company for Approval of an Energy Efficiency Program, Cost Recovery Mechanism, and Other Related Relief for Plan Years One Through Three, BPU Docket No. EO20090621, Order Dated April 27, 2021. Cost-Benefit Analysis Workbook; In re the Petition of Elizabethtown Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act and the Establishment of a Conservation Incentive Program, BPU Docket Nos. QO19010040 and GO20090619, Order Dated April 7, 2021, Cost-Benefit Analysis Workbook; In re the Verified Petition of Jersey Central Power and Light Company for Approval of JCP&L's Energy Efficiency and Conservation Plan Including Energy and Peak Demand Reduction Programs, BPU Docket No. EO20090620, Order Dated April 27, 2021, Cost-Benefit Analysis Workbook; In re the Petition of New Jersey Natural Gas Company for Approval of Energy-Efficiency Programs and the Associated Cost Recovery Mechanism Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 Et Seq. and 48:3-98.1 Et Seq., BPU Docket Nos. QO19010040 AND GO20090622, Order Dated March 3, 2021, Cost-Benefit Analysis Workbook; In re the Implementation of P.L. 2018, C. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs, BPU Docket Nos. QO19010040 and EO20090623, Order Dated June 9, 2021, Cost-Benefit Analysis Workbook; and In re the Petition of South Jersey Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act, BPU Docket Nos. QO19010040 & GO20090618, Order Dated April 7, 2021, Cost-Benefit Analysis Workbook.

[12] In re the Petition of Atlantic City Electric Company for Approval of a Portfolio of Energy Efficiency, Building Decarbonization and Demand Response Programs, a Cost Recovery Mechanism, and Other Related Relief Pursuant to the Clean Energy Act for the Period January 2025 Through June 2027 (Triennium 2), BPU Docket No. Qo23120871, Cost-Benefit Analysis Workbook; In re the Petition of Elizabethtown Gas Company for Approval of Triennium 2 Clean Energy Programs and Associated Cost Recovery Pursuant to the Clean Energy Act, BPU Docket No. QO23120869, Order Dated October 30, 2024, Cost-Benefit Analysis Workbook; In re the Verified Petition of Jersey Central Power & Light Company for Approval of JCP&L's Second Energy Efficiency and Conservation Plan Including Energy Efficiency and Peak Demand Reduction Programs ("JCP&L EE&C PLAN II FILING"), BPU Docket No. QO23120872, Order Dated October 30, 2024, Cost-Benefit Analysis Workbook; In re the Petition of New Jersey Natural Gas Company for Approval of New Energy Efficiency, Building Decarbonization Start-Up and Demand Response Programs and the Associated Cost Recovery Mechanism Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 Et Seq. and 48:3-98.1 Et Seq. Second Triennium, BPU Docket No. QO23120868, Order Dated October 9, 2024, Cost-Benefit Analysis Workbook; In re the Petition of Public Service Electric And Gas Company for Approval of Its Clean Energy Future-Energy Efficiency II ("CEF-EE II") Program on a Regulated Basis, BPU Docket No. QO23120874, Order Dated October 30, 2024, Cost-Benefit Analysis Workbook; In re the Petition of Rockland Electric Company for Approval of Its Energy Efficiency and Peak Demand Reduction Programs, BPU Docket No. QO23120875, Order Dated October 30, 2024, Cost-Benefit Analysis Workbook; and In re the Petition of South Jersey Gas Company for Approval of Triennium 2 Clean Energy Programs and Associated Cost Recovery Pursuant to the Clean Energy Act, BPU Docket No. QO23120870, Order Dated October 30, 2024, Cost-Benefit Analysis Workbook.

[13] In re Petition of Atlantic City Electric Company for Approval of a Voluntary Program for Plug-In Vehicle Charging, BPU Docket No. EO18020190, Order Dated February 17, 2021. ACE – Semi-Annual EV Charge Report – EO18020190 – 8-8-2025 "2-17-21-8F", Report dated February 18, 2021; In re Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future-Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis, BPU Docket No. EO18101111, Order Dated January 27, 2021. PSE&G – CEF-EV Report – January-June, 2025 EO18101111 "1-27-21-8A," Report dated February 3, 2021; In re Petition of Rockland Electric Company for Approval of an Electric Vehicle Program, Establishment of an Electric Vehicle Surcharge, and for Other Relief, BPU Docket No. EO20110730, Order Dated October 12, 2022. RECO SEMI-ANNUAL REPORT 091525 "10-12-22-8J", Report dated October 18, 2022; and In re Verified Petition of Jersey Central Power & Light Company for Approval of an Electric Vehicle Program and an Associated Cost Recovery Mechanism, BPU Docket No.

in kW per asset came from the responses to the RFI pursuant to EO 2 soliciting information on the design of the VPP.[14]

**Table 1. Existing VPP Capacity**

| EDC | Summer 2025 Weather Normalized Regional Transmission Operator ("RTO") Coincident Peaks (MW) | 3% Reduction in Capacity (MW) | DR Capacity with 75% Enrollment of Existing Assets (MW) | Portion of 3% Reduction in Capacity |
|---|---|---|---|---|
| PSE&G | 9,770 | 293.1 | 185.2 | 63% |
| JCP&L | 5,760 | 172.8 | 76.7 | 44% |
| ACE | 2,315 | 69.5 | 57.3 | 82% |
| RECO | 390 | 11.7 | 6.4 | 55% |
| **TOTAL** | **18,235** | **547.1** | **325.5** | **60%** |

These existing flexible-load resources are distinct from, but complementary to, the energy storage resources supported through Block 1, and together provide the initial resource base for the PowerUp NJ Program.

### iii. Grid Modernization

Staff is currently leading the Grid Modernization Forum, a collection of expert stakeholder workgroups focused on increasing DER hosting capacity and grid flexibility. The Integrated DER Workgroup is developing minimum filing requirements for EDCs to file Proactive System Upgrade Plans ("PSUPs") describing how each EDC will evolve its distribution grid into a more adaptive, flexible system with higher DER hosting capacity.[15] The Grid Flexibility Services ("GridFlex") Workgroup is developing recommendations for the service architecture for tariffs that enable interoperable DERs to provide distribution-level services and be compensated for them.[16]

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EO21030630, Order Dated June 8, 2022. JCPL EV SEMI-ANNUAL REPORT – JUNE 30 2025 – FILED 8.29.25 EO21030630 AND ER22030127 "6-86-22-8D", Report dated October 2, 2022.

[14] In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, Notice of Request for Information, BPU Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, & QO24030199, Comments dated May 20, 2026 ("ACE - NJVPP Response to RFI - QO26030099 - 5-20-2026"); In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, Notice of Request for Information, BPU Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, & QO24030199, Comments dated May 20, 2026 (PSE&G - PS_VPP_GSESP_1-75_Answer"); In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, Notice of Request for Information, BPU Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, & QO24030199, Comments dated May 20, 2026 ("2026-05-20 - JCPL RESPONSE TO RFI"); and In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, Notice of Request for Information, BPU Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, & QO24030199, Comments dated May 21, 2026 ("VPP RFI RECO RESPONSE FINAL").

[15] In re Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid, BPU Docket No. QO24030199, Notice dated June 5, 2024.

[16] In re Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid, BPU Docket No. QO26030059, Notice dated Apr. 8, 2026.

These Grid Modernization efforts are directly relevant to both the VPP Interim Program and Block 1. While Block 1 provides the near-term residential storage deployment pathway, the PSUP and GridFlex proceedings are expected to provide long-term compensation mechanisms for the stackable values provided by distributed storage and other DERs, and ensure these resources are made visible to EDCs, are coordinated with distribution-system needs, are dispatched to address locational constraints, and are ultimately integrated into standardized grid-flexibility services.

### iv. The Garden State Energy Storage Program

New Jersey law directs the Board to establish a process and mechanism for achieving 2,000 MW of installed energy storage by 2030.[17] Pursuant to that statutory directive, the Board established the GSESP by Order dated June 18, 2025 (”Launch Order”).[18] The GSESP is designed to support the deployment of energy storage resources that reduce electricity costs for ratepayers, support achievement of the State’s energy storage goals, promote private investment, facilitate integration of renewable generation and other distributed energy resources, improve resilience, and provide other system and societal benefits.

The Board structured the GSESP to proceed in phases. Phase 1 supports transmission-scale energy storage resources, while Phase 2 is intended to support distributed storage resources located on the distribution system either in front of the meter (“FTM”) or BTM. Staff issued Straw Proposals on September 29, 2022 and November 7, 2024,[19] establishing this phased approach and describing programmatic frameworks for each Phase. The Board launched Phase 1, Tranche 1 through the Launch Order and subsequently initiated Phase 1, Tranche 2 by Order dated March 4, 2026.[20] The Board deferred the launch of Phase 2 in the Launch Order, citing the need to undertake additional program design work. However, as noted above, EO 2 directed the Board to accelerate the deployment of distributed energy storage through GSESP Phase 2. As a result, Staff undertook a focused effort to further develop Phase 2 while aligning with the Board’s VPP efforts. As reflected in this Order, Block 1 of Phase 2 and the VPP Interim Program are intended to operate in a coordinated and mutually reinforcing manner as part of the PowerUp NJ Program. The VPP Interim Program provides the initial framework for aggregating, dispatching, measuring, verifying, and compensating customer-sited and distributed resources, while Block 1 provides the storage-specific compensation pathway for the first set of distribution-connected storage resources that can support peak-demand reduction, distribution-system flexibility, and future VPP participation. This Order therefore establishes Block 1 as a component program of the PowerUp NJ Program while preserving protections against duplicative compensation for the same underlying service, system benefit, or performance obligation.

### v. Related Proceedings

The Board has adopted Advanced Metering Infrastructure (“AMI”) data access rules at N.J.A.C.

[17] See N.J.S.A. 48:3-87.8.

[18] In re the Garden State Energy Storage Program (“GSESP”) Pursuant to P.L. 2018, c. 17, BPU Docket No. QO22080540, Order dated June 18, 2025 (“Launch Order”).

[18] In re the New Jersey Energy Storage Incentive Program, BPU Docket No. QO22080540, Straw Proposal dated September 29, 2022; In re the New Jersey Energy Storage Incentive Program (“NJESIP”) 2024 Straw Proposal Pursuant to P.L. 2018, c. 17, BPU Docket No. QO22080540, Straw Proposal dated November 7, 2024.

[20] In re the Garden State Energy Storage Program Phase 1, Tranche 2, BPU Docket No. QO25120634, Order dated March 4, 2026.

14:5-10. The rules establish customer ownership of AMI meter data, standardized data sharing through the Green Button Standard, and non-discriminatory third-party access to that data. [21]The Board has advanced managed EV charging, which EO 2 cites as a foundational VPP use case, through its light-duty and medium- and heavy-duty EV charging orders and the recent extension of the EDCs' light-duty EV programs. Net energy metering ("NEM") reform and time-of-use rate design remain under consideration in separate proceedings.

On August 4, 2025, the Board published proposed new rules to establish the GSESP regulatory framework, encompassing both transmission-connected (Phase 1) and distribution-connected energy storage (Phase 2), including fixed and performance-based incentives for Phase 2.[22] The public comment period for the original proposal closed on October 3, 2025. On September 8, 2026, the Board published a Notice of Proposed Substantial Changes upon Adoption ("NOPSCUA") to the proposed GSESP rules.[23] Most notably, the NOPSCUA proposed removing all previously proposed Phase 2 distributed-storage provisions, including the fixed and performance incentive structures and related EDC responsibilities, thereby narrowing the pending rulemaking to the Phase 1 segment. This action reflected the need to substantially redesign Phase 2 in response to EO 2's VPP directive and stakeholder feedback. The Board intends to advance the redesigned distributed-storage program through separate proceedings, including the GSESP Phase 2, Block 1 framework established by this Order. The NOPSCUA comment period closed on November 7, 2026.

### vi. The Joint Request for Information, the VPP Straw Proposal, and the Residential Storage Program Straw Proposal

On April 20, 2026, Staff issued a joint RFI pursuant to EO 2 soliciting information on the design of the VPP Program and Phase 2 of the GSESP, to ensure that the two programs are developed in a coordinated and mutually reinforcing manner.[24] Responses were due May 20, 2026, and informed Staff's development of the VPP Straw Proposal and Block 1.

On July 17, 2026, Staff issued the VPP Straw Proposal under Docket No. QO26030099.[25] The Straw sets out a two-phase implementation framework – a near-term, EDC-administered VPP Interim Program and a long-term, open-access VPP framework – together with proposals addressing compensation, DER Management System ("DERMS") architecture, DER Aggregator licensing and a code of conduct, cybersecurity, data access, equity, marketing, cost recovery, and cross-program coordination. Comments on the VPP Straw Proposal were due August 17, 2026. Together with the Joint RFI, issuance of the VPP Straw Proposal commenced development of the VPP program within the 180-day period directed by EO 2.

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[21] In re Minimum Filing Requirements for Light-Duty, Publicly-Accessible Electric Vehicle Charging, BPU Docket No. QO20050357, Order dated Sept. 23, 2020 (revised on Oct. 20, 2020, to correct a typographical error); In re Medium and Heavy-Duty Electric Vehicle Charging Ecosystem, BPU Docket No. QO21060946, Order dated Oct. 28, 2024.

[22] 57 N.J.R. 1651(a) (Aug. 4, 2025).

[23] 58 N.J.R. 1981(a) (Sept. 8, 2026).

[24] In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, Notice of Request for Information, BPU Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, & QO24030199, Notice dated April 20, 2026 ("Joint RFI").

[25] In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, Notice of Straw Proposal, BPU Docket No. QO26030099, Notice dated July 15, 2026 ("VPP Straw Proposal").

On August 17, 2026, Staff issued the Block 1 Straw Proposal under Docket No. QO26040116.[26] The Block 1 Straw Proposal included a framework to support near-term deployment of distributed storage while preserving flexibility for future program development. The Block 1 Straw Proposal framework included details on program size and incentive levels, program timeline, EDC-administration, customer eligibility, enrollment, interconnection coordination, dispatch events and communication, performance measurement and verification, incentive payment administration, cost recovery, reporting, and customer protections.[27] The Block 1 Straw Proposal also reflected the need to coordinate distribution-connected storage deployment with the VPP Interim Program, future grid-flexibility services, and the Board's broader grid modernization efforts, while avoiding duplicative compensation for the same service, system benefit, or performance obligation. Comments on the Straw were due September 10, 2026.

## vii. Summary of the VPP Straw Proposal Comment

The Board received a total of seventy-five (75) comment submissions on the VPP Straw Proposal. Staff has reviewed all comments received. The summary below describes the principal themes by category of commenter and is not exhaustive. **Attachment C** provides a more detailed description of the comments and Staff responses.

***1. Utilities [EDCs and gas distribution companies ("GDCs")]***

The EDCs generally supported an EDC-administered interim program that builds on existing Triennium 2 DR infrastructure and enrolled customer bases. They sought greater flexibility in program design, cautioned that the proposed timeline is compressed relative to the systems integration required, and asked the Board to address cost recovery treatment and the relationship between interim program obligations and existing DR contracts. Several sought clarifications on the division of operational responsibility between the EDC, its implementation contractor, and third-party aggregators.

***2. The New Jersey Division of Rate Counsel ("Rate Counsel")***

Rate Counsel emphasized ratepayer affordability, urged that program costs be recovered as an expense rather than capitalized into rate base, and sought firm budget limits and demonstrated cost-effectiveness before program approval. Rate Counsel also pressed for a clear showing of how system-level savings translate into customer bill reduction.

***3. Technology providers, developers, OEMs, and other market participants***

Technology providers developers, original equipment manufacturers ("OEMs"), and other market participants supported the two-pathway service model and the commitment to technology neutrality, and urged the Board to strengthen non-discriminatory access provisions, standardize interoperability and communication protocol requirements across EDCs, and provide revenue certainty adequate to justify customer acquisition investment. Several recommended a longer contract term and a defined minimum customer pass-through. Many argued that the proposed annual cap of 35 dispatch events is too low to support a viable business case and understates the value the resources can deliver.

***4. Trade associations***

[26] In re the Garden State Energy Storage Program – Phase 2 Distributed Storage in the State of New Jersey, Notice of Straw Proposal, BPU Docket No. QO26040116, Notice dated August 17, 2026 ("Block 1 Straw" or "Block 1 Straw Proposal").
[27] Id.

Trade associations representing solar, storage, vehicle-grid integration, advanced energy, and smart device manufacturers supported the program framework and focused on market access. Their recommendations centered on competitive procurement, avoidance of EDC self-dealing, a defined licensing pathway for aggregators, and coordination between the interim program and the NEM, storage, and EV charging proceedings so that a single resource is not subject to inconsistent treatment.

***5. Environmental, consumer, and environmental justice organizations***

These commenters supported the peak demand reduction objective and urged more aggressive targets. They recommended enforceable low and moderate-income ("LMI") participation requirements rather than narrative descriptions, protections against enrollment practices that disadvantage vulnerable customers, and explicit attention to overburdened communities in program design and marketing.

***6. Consultants, academic commenters, and other members of the public***

These commenters focused on measurement and verification, recommending standardized baseline methodologies, independent verification, and consistent evaluation protocols across EDCs so that program results are comparable. Several addressed the selection of cost-effectiveness tests and the treatment of avoided capacity and transmission costs.

## viii. Summary of the Block 1 Storage Programs Straw Comments

The Board received a total of sixty-eight (68) comment submissions, including written and verbal comments, on the Block 1 Straw Proposal. The summary below describes the principal themes by category of commenter and is not exhaustive. **Attachment D** provides a more detailed description of the comments and Staff responses.

***1. Utilities***

Utilities generally supported Block 1 as a measured, performance-based first step toward broader distributed storage deployment, while urging a flexible framework that preserves utility authority over dispatch and distribution-system reliability. They emphasized coordination with VPP, GridFlex, and related DER proceedings; clear operational roles; appropriate telemetry and DERMS capabilities; timely cost recovery; realistic implementation schedules; and flexibility to refine event parameters, incentives, and eligibility based on early experience. Several also supported small-commercial participation and upfront, hybrid, or targeted incentives to address customer-cost and LMI participation barriers, while views differed on whether BTM resources should be served through a single consolidated program or distinct but coordinated program pathways.

***2. Rate Counsel***

Rate Counsel supported distributed storage when it addresses an identified system need, performs reliably at the necessary time and location, and produces measurable and verifiable net customer savings, but cautioned that the proposed noncompetitive 150 MW block could impose substantial ratepayer costs without demonstrating improved affordability. Rate Counsel recommended treating $200/kW-year as a Block 1 maximum, using competitive price discovery and locational targeting, and coordinating Phase 2 with the VPP through one compensation pathway by default, a resource registry and compensation ledger, and dollar-for-dollar offsets if

stacking is allowed. Rate Counsel also urged a Benefit Cost Analysis ("BCA") incorporating all costs, alternatives, downside sensitivities, class-level bill impacts, and retrospective validation, together with cost-causation-based administrative recovery, hard budget caps, uniform dispatch standards, and affirmative Board review before expansion.

***3. Technology providers, developers, OEMs, and other market participants***

Technology providers, developers, OEMs, and other market participants generally supported advancing a performance-based distributed-storage program but urged broader and more certain market access for small-commercial and other commercial and industrial ("C&I") resources, existing or transitional systems, third-party ownership arrangements, and other resource configurations; some also called for an accelerated or parallel FTM pathway. Commenters commonly recommended measuring performance using average verified output or committed delivery rather than the minimum discharge during a dispatch event, establishing predictable event duration, frequency, and notice, and allowing EDCs to identify grid needs and call events while aggregators, OEMs, or edge DERMS platforms execute device-level dispatch through interoperable telemetry and settlement standards. They also emphasized financeable incentive levels and terms, customer backup reserves and transparent pass-through arrangements, streamlined interconnection and export treatment, and service-specific rules that recognize distinct and locational grid values while preventing duplicate compensation.

***4. Trade associations***

Trade associations generally supported a performance-based distributed storage program but suggested the Board should establish a larger Block 1, stronger compensation, and near-term pathways for existing systems, C&I resources, V2G, and FTM storage. They recommended using average verified output for performance payments, increasing dispatch events with clear notice and emergency-event rules, preserving export and NEM eligibility, and accommodating varied Third Party Owner ("TPO"), aggregation, OEM, and supplier business models. Commenters also sought uniform statewide operating standards, transparent valuation of grid benefits, expedited interconnection, and a firm GridFlex/FTM development schedule.

***5. Environmental, consumer, and environmental justice organizations***

Environmental, consumer, and environmental justice commenters supported distributed storage deployment but urged the Board to adopt binding measures ensuring that LMI households and overburdened communities ("OBCs") can participate and receive measurable economic and resilience benefits. They proposed varying mechanisms, including community-benefit capacity reserves, community-ownership and procurement set-asides, enforceable customer pass-through or host-benefit standards, OBC-focused incentives and revenue requirements, demographic reporting, and community oversight, while also seeking enrollment rules that accommodate renters, multifamily properties, nonprofits, and community-based owners. Commenters further recommended responsible-contractor and apprenticeship standards, full interoperability with future VPP programs, and transparent interconnection, dispatch, and value-stacking rules that protect customer resilience and prevent duplicate compensation.

***6. Consultants, academic commenters, and other members of the public***

Consultants, academic commenters, and other members of the public generally supported expanding distributed storage and recommended broader participation by municipal utilities and cooperatives, small-commercial customers, existing resources, and TPS, together with technology-neutral treatment of battery, thermal, and emerging storage applications.

Commenters emphasized simple and transparent compensation and financing rules, including measurement based on delivered energy or average output, clearer event parameters and payment schedules, on-bill repayment and plain-language disclosures, and recognition of distinct distribution, capacity, transmission, export, and resilience values without duplicate compensation. They differed regarding operational control: some favored EDC-owned, substation-sited, or EDC-directed resources for localized grid needs, while others preferred municipal, participant, aggregator, or autonomous-inverter control, supported by coordinated interconnection, VPP interoperability, and locational or pilot-based testing.

# II. STAFF'S RECOMMENDATIONS

## A. PowerUp NJ Program

New Jersey faces an electricity affordability crisis. EO 1 declared an electricity affordability emergency, and EO 2 found that the capacity shortage in the PJM region raises serious concerns about both affordability and reliability. EO 2 directed the Board to commence development of a VPP program and to accelerate the launch of Phase 2 of the GSESP. In response, this Order establishes the PowerUp NJ Program. PowerUp NJ brings two component programs, the VPP Interim Program and Block 1, together under one coordinated framework. Both rely on new and existing customer-sited resources, including, but not limited to, energy storage, smart thermostats, EV chargers, and other smart appliances. These resources can often be enrolled or installed more quickly than new power plants can be built.

PowerUp NJ is designed to reduce peak demand, accelerate the deployment of distributed energy storage, and improve the flexibility of the distribution system. Lower peak demand can reduce the capacity and transmission costs assigned to each EDC zone, and any resulting savings will broadly benefit ratepayers in that zone, not just program participants. Reducing demand at peak times may also help ease strain on the grid when supply is tight. In addition, PowerUp NJ is intended to demonstrate that customer-sited resources can be reliably dispatched, measured, and verified, and to gather the necessary operational data needed to improve future storage blocks and design the long-term, open-access VPP program. PowerUp NJ is intended to continuously build an open, competitive market in which customer-sited resources are compensated for the grid services they provide and serve as a reliable option for meeting New Jersey's growing electricity demand.

### i. Program Overview

To provide consistency across the State, Staff recommends that PowerUp NJ be the name for all programs established under this Order. Each EDC will offer and market its programs under this name. PowerUp NJ has two component programs: the VPP Interim Program and Block 1. Both programs are designed to work together to leverage various DERs to reduce peak demand and thereby lower retail electricity prices. A Host Customer, as defined in Section II.A.ii, may take part in both at the same time, using different devices, under the rules described below.

The VPP Interim Program compensates Host Customers who use customer devices, such as smart thermostats, EV chargers, and other smart appliances, which can reduce demand during EDC Dispatch Events. Host Customers participate in the VPP Interim program through a VPP Provider, and the flow of payments depends on the VPP Provider's role and the participation model implemented. Under the DER Provider participation model, a Host Customer's devices are enrolled through one or more DER Provider(s). In this model the EDC measures the Site's net load reduction at the retail meter, after removing the charge and discharge of any storage system enrolled in Block 1, and pays the Host Customer directly, or through the EDC's contractor,

for that performance. The EDC separately pays each DER Provider an amount under its contract with the EDC for reliably providing device data and carrying out dispatch signals. A DER Provider is not paid for, and is not responsible for, the Site's total kW performance. A DER Provider may serve multiple Host Customers and may manage multiple devices for a single Host Customer. Under the Site Aggregator participation model, a Site Aggregator enrolls the entire Site in the VPP Interim Program. In this model, the EDC measures the Site's load reduction at the retail meter and pays the Site Aggregator per kW delivered. The Site Aggregator bears the performance risk, compensates the Host Customer under their agreement, and is expected to retain a share of that payment for its services, as described in Section II.B.vi.

The Block 1 program pays performance incentives for residential and small commercial energy storage devices that respond to similar EDC Dispatch Events. Host Customers participate in the Block 1 only by contracting with a DER Provider that enrolls and dispatches the customers' energy storage devices, interfaces with the customer's EDC, and collects payments for successful dispatch from the EDC on behalf of the Host Customer. More than one physical energy storage device may participate at a Site, but they must be enrolled as a single Block 1 resource by a single DER Provider. A DER Provider participating in the Block 1 program may be a TPO, as defined in Section II.A.ii, or an entity that the Host Customer contracts with to manage an energy storage device that the Host Customer owns. In Block 1, unlike in the VPP Interim Program, the EDC pays the full Block 1 incentive to the DER Provider, not to the Host Customer, as described in Section II.C.iii. The DER Provider will pass the agreed upon share of the incentive on to the Host Customer, potentially in the form of a reduced lease or contract payment, or a direct monetary payment. The Block 1 program will let private negotiation between DER Provider and the Host Customer determine each party's share of Block 1 compensation and how the DER Provider will pass on the value of the Host Customer's share.

A Host Customer that wishes to participate in both the VPP Interim Program and Block 1 may have one DER Provider managing their energy storage device enrolled in Block 1 and the same or another DER Provider managing their VPP Interim devices. A Host Customer may alternatively opt to have their energy storage device and all other devices at the Site managed by a Site Aggregator, but in that case the energy storage device would participate in the VPP Interim Program as part of that Site. Its device data would not be used to measure performance and it would not receive Block 1 compensation. Section II.A.iii sets out these rules.

### ii. Key PowerUp NJ Program Definitions

The following definitions apply to the PowerUp NJ Program and explain its key nomenclature. They have the same meaning throughout this Order and its Attachments. Other terms are explained in the sections where they are used. Specifically:

"Awarded Storage Capacity" means the nameplate power output of an energy storage system, measured in kilowatts of alternating current ("kW AC" or "kW"), which is eligible to be dispatched and used for calculation of incentive payments under the Block 1 Program. While a storage system's entire nameplate capacity will be enrolled in Block 1, the amount discharged during Dispatch Events remains at the discretion of the DER Provider. The system may discharge such that a portion of storage capacity is withheld for backup power, as determined by the DER Provider and Host Customer.

"DER Provider" means an entity that enrolls an individual device at a Site, such as a smart thermostat, an EV charger, or a battery, in the VPP Interim Program or Block 1, and dispatches that device during EDC Dispatch Events. A DER Provider may also be a TPO that owns the device it manages. A Site can host more than one DER Provider. No single device can be

enrolled by more than one DER Provider.

"DERMS Provider" means an entity that supplies the software platform an EDC uses to manage and dispatch DER Providers. A DERMS Provider contracts with the EDC as part of the EDC's systems and implementation services. It is not a VPP Provider unless it also enrolls devices or sites.

"EDC Dispatch Events" means the time periods in which EDCs call upon resources participating in the VPP Interim or Block 1 programs to shave load during peak hours, relieve distribution-level thermal constraints, reduce local congestion, and/or address other qualifying grid stress conditions.

"Host Customer" means the retail electric customer of record for a Site who contracts with one or more DER Providers or a Site Aggregator to manage the participation of the devices at that Site in the VPP Interim Program, the Block 1 Program, or both. In Block 1, the Host Customer must contract with a DER Provider. Depending on how its devices are enrolled, the Host Customer receives payment directly from the EDC or its contractor, through its Site Aggregator, or, for a storage system enrolled in Block 1, through its DER Provider, as described in Section II.A.i.

"Performance Factor" means the ratio of the actual discharge of a storage device enrolled in Block 1 during EDC Dispatch Events to its Awarded Storage Capacity. The resulting percentage determines the share of the applicable incentive ($/kW) earned by the device, not to exceed 100%. See Attachment E for specific details on earned incentives.

"Site" means a single retail electric meter and all devices behind that meter on the Host Customer side. A Host Customer's premises served by more than one retail electric meter contains more than one Site. The Site is the entity that a Site Aggregator enrolls in the VPP Interim Program. Its meter data is used to determine all VPP Interim Program performance, whether the Site is enrolled through a Site Aggregator or through one or more DER Providers. The rules in Section II.A.iii apply to each Site separately.

"Site Aggregator" means an entity that enrolls a Host Customer's entire Site in the VPP Interim Program and is responsible for all DER performance at that Site. Performance is measured in kW at the Site's retail meter against the Site's baseline. The Site Aggregator is paid by the EDC based on the kW it delivers and bears the risk if the Site does not perform. The Site Aggregator may manage any device at the Site in any way it chooses, consistent with this Order and agreements made with the Host Customer.

"Third Party Owner" or "TPO" means any entity, other than the Host Customer, that owns an energy storage device or other DER located on a Host Customer's Site that is not the Host Customer.

"VPP Provider" means a Site Aggregator or a DER Provider. A VPP Provider uses technology to dispatch or curtail one or more DERs located on the customer side of the meter in response to a signal, to deliver a measurable reduction in demand.

### iii. VPP Provider Roles at a Site

Staff recommends the following rules:

1. A Site may be served either by 1) one Site Aggregator, which enrolls the site, or 2) one or more DER Providers, which enroll individual devices. It may not be served by a Site Aggregator as well as a DER Provider. When a Site is served by one or more DER

Providers, each is accountable for the participation of its associated device, including enrollment, monitoring, dispatch, and reporting. When a Site Aggregator enrolls a Site, the Site, not the individual devices, is enrolled in the program.

2. A Host Customer may have the same or different DER Providers for different devices.

3. The VPP Provider through which a Block 1 resource participates may only be a DER Provider. In other words, if a Block 1 device is enrolled at a Site, that Site may not be enrolled by a Site Aggregator. Other devices at that Site may enroll in the VPP Interim Program through DER Providers, however. At such a Site, the EDC shall measure VPP Interim Program performance at the retail meter, after subtracting the storage system's net injection (positive for discharge, negative for charge), as measured by the storage system's meter, from both the Site's baseline and the event load.

4. A Site Aggregator that manages an entire Site may include a storage system located at that Site as part of the Site's participation in the VPP Interim Program. That storage system may not be enrolled in Block 1, however, and would not receive Block 1 compensation. It would serve to improve Site demand response performance at the retail meter.

Any type of entity, including, but not limited to a TPO, third-party supplier ("TPS"), or original equipment manufacturer ("OEM") may serve as a VPP Provider if it meets the eligibility criteria to be a Site Aggregator or DER Provider established by this Order. Examples include OEMs that operate a control platform for their own devices, TPS companies, energy management and software providers, solar and storage installers that retain operational control of installed systems, EV charging network operators, and building controls and energy services companies. This list is illustrative, not exhaustive.

Staff notes that a Site Aggregator under this Order is distinct from a DER Aggregator under FERC Order No. 2222 and PJM's tariff, and from a PJM Curtailment Service Provider. A VPP Provider under these programs need not be registered with PJM, and registration with PJM does not by itself qualify an entity to participate.

## B. Program 1: The VPP Interim Program

### i. Program term and objectives

Staff recommends that each EDC be required to propose, and upon Board approval administer, a VPP Interim Program operating from October 1, 2027, through September 30, 2029, as the first phase of New Jersey's two-phase VPP implementation. The VPP Interim Program should use the EDCs' current DR and VPP pilot programs as a foundation. The VPP Interim Program is expressly transitional and is designed to facilitate, rather than impede, migration of enrolled DER assets into the long-term open-access tariff framework as it becomes operational. The VPP Interim Programs shall be designed as clean energy, technology-neutral programs, defined by the grid services to be delivered and the technical requirements necessary to demonstrate reliable delivery rather than by particular DER types or manufacturers, and shall build on existing AMI infrastructure, the EDCs' Triennium 2 DR programs, and enrolled Triennium 2 DR customer bases. Staff recommends that any VPP Interim compensation paid to a Host Customer, whether by the EDC or by a Site Aggregator, be made by direct monetary payment, such as check, electronic funds transfer, or gift card, and not as a credit on the Host Customer's electric bill.

The ultimate purpose of the VPP Interim Program is to deliver maximum ratepayer benefits through reducing overall capacity, transmission, and distribution costs as well as bringing other

benefits. In addition to providing ratepayer savings through the reduction in peak demand, the VPP Interim Program will lay the groundwork for the eventual stacking of compensation for distinct grid services. With that in mind, Staff proposes the following program objectives, all of which should be achieved at minimum net cost to ratepayers.

### ii. Staff recommends the following objectives for the VPP Interim Program:

1. Reduce peak demand by no less than three percent (3%) across each EDC service territory beginning no later than **October 1, 2027**, through coordinated dispatch of enrolled Sites and individual DERs enrolled in the VPP Interim Program. Storage systems enrolled in Block 1 will be excluded from this target. EDC Dispatch Events shall be designed to reduce peak demand, which should be informed by a reliable forecasting mechanism of PJM's Capacity 5 Coincident Peaks ("5CP") and each EDC's Transmission 1 Coincident peak ("1CP"). EDC Dispatch Events must also meet the requirements of their Peak Shaving Adjustments ("PSAs" or "PSA") filed with PJM. EDC Dispatch Events may additionally be called to mitigate distribution-level thermal constraints, local congestion, and other qualifying grid stress conditions as determined by EDCs. Dispatch protocols should be designed to result in ratepayer savings, and to test localized dispatch, in order to inform future infrastructure deferral via targeted VPP services;
2. Demonstrate reliable and accurate delivery of grid services using existing utility and VPP Provider systems, and demonstrate evaluation, measurement, and verification ("EM&V") capability using existing AMI systems;
3. Gather operational data – including event response rates, baseline accuracy, resource mix performance, dispatch latency, and Host Customer DER selection behavior – to inform the technical requirements and compensation design of the long-term tariff;
4. Enable customer familiarization and trust-building with VPP participation, creating an enrolled customer base from which the long-term, VPP Provider-led market can grow;
5. Test and validate communication protocols, performance measurement methodologies, and data reporting standards between EDCs and VPP Providers that will carry forward into the long-term framework;
6. Establish a structured, competitive EDC-VPP Provider framework that progressively builds VPP Provider operational capacity, market experience, and enrolled customer bases;
7. Evaluate compensation structures, which may include fixed enrollment payments and pay-for-performance models, to inform tariff design for the long-term framework; and
8. Quantify retail peak load reduction, distribution-level grid service values and other ratepayer savings, establishing the evidentiary foundation for future procurement of locational distribution network benefits and for evaluation metrics that measure savings to all ratepayers.

All VPP Interim subprograms, including those migrating from the Triennium 2 DR portfolio, shall be operational by **October 1, 2027,** so that new resources are available for the start of the 2027 winter season. It is essential to assess how the dispatch of these resources can reduce distribution and transmission costs outside of the summer season, and to ensure that resource performance during every season is assessed at least twice across the lifespan of the program. Programs should be designed to run through **September 30, 2029**.

### iii. Eligibility, aggregation thresholds, and technical standards

The VPP Interim Program is designed as a clean energy, technology-neutral program and shall be open to all DER types capable of delivering dispatchable demand reduction on a reliable, event-driven basis. Eligibility shall not be limited to any specific device class, vendor, or communication platform. Staff recommends that the programs build on existing grid infrastructure and customer-owned DER assets – including, but not limited to, smart thermostats, smart water heaters, and EV chargers – rather than requiring new customer-side hardware at launch. Additional devices added over the program period may be purchased with hardware incentives offered under other Board-approved programs, provided those incentives do not duplicate VPP compensation. Future DER incentives may target solar and storage, including vehicle-to-grid ("V2G") capable EVs, but at the present time those devices are compensated for their contribution to the grid through other programs (e.g., solar renewable energy credits) or through hardware incentives (e.g. EV charger incentives). Until the Board orders otherwise, customers with solar-only systems on a NEM tariff may not enroll those solar systems in the VPP Interim Program, to avoid paying twice for the same value. An energy storage system, including the storage component of a solar-plus-storage system, may only be enrolled in Block 1, through a DER Provider, as described in Section II.C. A storage system may participate in the VPP Interim Program only as part of a Site enrolled by a Site Aggregator, as provided in Section II.A.iii. Staff recommends a minimum aggregation size threshold of 10 kW per program event, set lower than the 100 kW threshold contemplated for the long-term tariff. Device communication may involve an open-standard protocol or rely on proprietary application programming interfaces ("APIs") between the EDC's DERMS and VPP Providers.

Staff does not recommend a standalone definition or separate program treatment for V2G. V2G-capable vehicles are a form of customer-sited storage and are covered by the technology-neutral framing above; however, Staff does not recommend V2G be eligible for Block 1 enrollment. V2G compensation will be considered in the long-term framework, which is planned to be technology-neutral.

### iv. Event dispatch protocol

Staff recommends that EDCs be required to include dispatch protocols in their filing. Staff further recommends that EDC Dispatch Events target periods of high grid stress, as determined by the EDC in coordination with PJM, to ensure such dispatches result in reduced wholesale charges. The following parameters should apply:

1. maximum event duration of three (3) hours per event;
2. no more than twenty (20) events per summer season (June 1 through September 30) and ten (10) events per winter season (December 1 through the last day of February), with no more than thirty-five (35) dispatch events per calendar year in total. Test calls to confirm system readiness do not count toward the thirty-five (35)-event total;
3. minimum advance notification of twenty-one (21) hours for standard events and thirty (30) minutes for grid stress events;
4. Host Customer opt-out rights for any individual event, subject to the understanding that frequent opt-outs may affect Host Customer incentive payments; and
5. DERMS or other dispatch platform capability to segment enrolled resources by substation, feeder, technology type, and response capability, enabling dispatch of specific resources that provide grid value for a particular event (not simply all-call).

Seasonal resources, such as smart thermostat-controlled air conditioning, will not be available for

all events. This does not warrant exclusion from the program but may affect performance measurement.

An EDC may propose additional or shorter-notice dispatch opportunities when supported by operational need or a demonstrated incremental ratepayer benefit, provided sufficient participant capability and protections. Each EDC shall define in its filing the conditions that qualify as a grid stress event and how it will decide day-ahead or in real time to call one. EDCs should test localized DER dispatch in order to gather data, gain team experience and lay the foundation for future infrastructure deferral via targeted VPP grid services. EDCs are encouraged to closely involve their planning and operations teams in this testing.

### v. Performance measurement and EM&V

Staff recommends that performance measurement be based on a Site-specific baseline methodology using verified AMI interval data, with the baseline for each enrolled Site calculated as a weighted average of that Site's usage during a specified number of non-event days immediately preceding the event. For a Site with a storage system enrolled in Block 1, the storage system's charge (discharge), as measured by the storage system's meter, should be added to (subtracted from) both the baseline and the event load, as provided in Section II.A.iii. Baseline methodologies should account for prior event dispatch to ensure that they do not reduce the baseline. Each EDC shall propose its methodology in its filing, including the number of reference days, weather-normalization adjustments, and treatment of Sites with seasonal load profiles.

Staff recommends that an EM&V subgroup be established within the PowerUp NJ Working Group to develop the shared EM&V metrics and methodology. This subgroup shall submit its proposed shared metrics and methodology to Staff for approval within sixty (60) days of Board approval of the EDC petitions. Staff shall approve, deny, or deny in part the proposal within twenty-one (21) days. Until Staff approves the shared metrics and methodology, each EDC shall use the metrics and methodology approved in its petition. Once approved, the shared metrics and methodology shall take effect within thirty (30) days.

Because prudence review, the program evaluation, and any potential future performance mechanism may rely on verified savings, Staff recommends that verification of program savings be performed by an independent evaluator retained by the Board rather than by the EDC. Staff further recommends that Staff conduct a review for the first twelve (12) months of each EDC's VPP Interim Program operation ("Midterm Review"). The Midterm Review will be based on each EDC's Midterm Report, which is its Year 1 Annual Report, as described under Reporting below. Staff will begin the Midterm Review upon receipt of the Midterm Reports. Based on the Midterm Review, the Board will determine whether the program should be modified, expanded, or phased out in favor of the long-term framework.

### vi. EDC and VPP Provider coordination

The VPP Interim Program shall be EDC-administered and delivered through a combination of EDC staff and contracted implementation contractors, which may include edge DERMS Providers, consistent with the operating model of the Triennium 2 DR pilots. The EDC shall send dispatch signals to the Host Customer's VPP Provider, which controls the Host Customers' devices. OEM and other VPP Provider relationships established under an EDC's existing Triennium 2 DR programs may continue and transition into the VPP Interim Program. An EDC shall not restrict participation in the VPP Interim Program to a single type of VPP Provider or limit the number of VPP Providers that may participate. EDCs shall make a good faith effort to contract with any VPP Provider that meets its VPP Provider requirements. An EDC may decline only if the VPP Provider does not meet those requirements or does not sign the EDC's Board-approved

participation agreement, which shall apply the same terms to all VPP Providers, including those the EDC procures or carries over from Triennium 2. An EDC may include in contract terms the reasonable, incremental cost of technical integration with a VPP Provider, except for VPP Providers already integrated with the DERMS or edge DERMS platform the EDC uses for the program. Any competitive procurement by an EDC shall be limited to its own systems and implementation services, which can include VPP Provider(s) or DERMS Provider(s).

An EDC's selection of a VPP Provider through competitive procurement shall not limit participation by any other VPP Provider that meets the VPP Provider requirements. Site and DER enrollments shall be accepted on a first-come, first-served basis and an EDC may pause new enrollments when projections indicate that the EDC has reached its program budget. EDCs shall provide the terms of enrollment in their petitions.

To the greatest extent possible EDC-VPP Provider contracts should use standard terms that apply equally to all VPP Providers. All contracts must include: (1) a methodology by which VPP Provider payments are progressively reduced or eliminated based on fulfillment of required services; and (2) a transition clause enabling Host Customers enrolled through a VPP Provider to migrate to the long-term open-access tariff without re-enrollment, together with a parallel-operation period of no less than twelve (12) months during which both the interim contract and the long-term tariff are available. Each EDC-DER Provider contract shall compensate the DER Provider for reliably providing enrollment, monitoring, dispatch, and reporting services, and not for the Site's kW performance, as described in Section II.A.i. All EDC-Site Aggregator contracts must be performance-based. EDC-Site Aggregator contracts must additionally include (3) a ceiling on the cost per kW of dispatched demand reduction consistent with avoided-cost benchmarks; and (4) a contracted MW commitment, including incremental enrollment goals over the contract term.

For the VPP Interim Program, Staff recommends that the structure and design of the incentive levels must be proposed by the EDCs in their filings. The incentive's value should remain consistent with the companion storage incentive, however, which spans $100-$200/kW. Staff further recommends that the EDCs set a goal of passing through to Host Customers no less than seventy percent (70%) of the compensation that a Site Aggregator receives for each Site, and that each EDC report its actual pass-through against that goal. This goal does not apply to DER Providers, because the EDC pays a Host Customer enrolled through DER Providers directly, as described in Section II.A.i. This goal does not apply to devices owned by a TPO, because the TPO pays for and owns the device and the Host Customer may receive little or no direct compensation. Staff recommends that this be established as a goal with tracking rather than as a contractual mandate at this stage, so that the Board can observe actual pass-through practice across the EDCs and a range of Site Aggregator business models before setting a binding floor.

## C. Program 2: Block 1 Program Overview

### i. Program term and objectives

Staff recommends that each EDC be required to propose, and upon Board approval, administer Block 1 as the initial distributed energy storage capacity block within the PowerUp NJ Program.

Staff recommends that Block 1 make incentive capacity available for the enrollment of up to 150 MW of new storage and 100MW of existing storage enrollments from BTM storage resources at residential and small commercial customer premises. For purposes of Block 1 eligibility, Existing Storage ("Existing Storage") shall mean any residential or small commercial storage system that achieves its Commercial Operation Date ("COD") before the effective date of this Order; and New Storage ("New Storage") shall mean any residential or small commercial storage system that

achieves its COD on or after the effective date of this Order. Retrofits or expansions of existing storage installations are eligible for participation in Block 1 and will be eligible only for the incentive level available to Existing Storage resources under the Block 1 framework. Staff recommends that differentiated incentive levels be applied to New Storage and Existing Storage to reflect the differing levels of investment needed to drive new deployment, while still recognizing the value of systems already in service.

Staff recommends that EDCs allow New or Existing Storage resources to start enrolling within sixty (60) days after the Board's approval of the EDCs' filings in response to this Order. Enrollment will proceed through an open, first-come, first-served process until the full 250 MW of Block 1 capacity is subscribed or the Board determines that enrollment should close. Awarded resources should be required to achieve COD within the timeframe established by the EDC and approved by the Board, anticipated to be no later than twelve (12) months from the date of award, subject to approved extensions for circumstances beyond the applicant's reasonable control.

Staff recommends that Existing Storage resources adhere to the same performance and technical requirements and answer the same calls as New Storage resources participating in Block 1.

### ii. Staff recommends the following terms and objectives for the Block 1 Program:

Staff recommends the Board set a maximum incentive rate of $200 per kW of Awarded Storage Capacity for New Storage, which represents the maximum annual incentive payment available to a project assuming a 100% Performance Factor. Staff recommends an incentive rate of $100 per kW of Awarded Storage Capacity for Existing Storage, which represents the maximum annual incentive payment available to each project assuming a 100% Performance Factor. Staff believes that customers with an existing system should receive the $100 per kW incentive instead of the full $200 per kW incentive, which is designed to encourage new installations.

Though Awarded Storage Capacity will determine participating storage resources' maximum incentives, Staff emphasizes that the actual performance-based payments will be based on the kW that participating storage resources discharge during EDC Dispatch Events. The amount discharged during Dispatch Events remains at the discretion of the DER Provider. Participating storage resources are expected to respond according to their specific system settings which may require a minimum reserve be withheld from discharge. For example, a New Storage resource with 10 kW of Awarded Storage Capacity that consistently discharged 5 kW during EDC Dispatch Events would be assigned a fifty percent (50%) Performance Factor and earn an annual incentive of $1,000. In this stylized example, one could think of the New Storage resource as being paid $200 for each of the five (5) kW it actually discharged. However, in reality, storage resource performance will almost certainly vary across EDC Dispatch Events. To account for that variability, Staff therefore recommends defining the annual incentive paid to a participating storage resource as its applicable incentive rate multiplied by its Awarded Storage Capacity multiplied by its Performance Factor. The precise methodology for calculating the Performance Factor is set forth and explained in Attachment E.

Staff recommends that Block 1 provide annual performance-based incentive payments over a ten-year term, with payments tied to verified discharge performance during EDC Dispatch Events. Incentive payments are earned only through verified performance during EDC Dispatch Events and are not provided for installing a storage system. Resources that fail to perform during Performance Intervals will receive proportionally reduced compensation through the Performance Factor methodology. EDC Dispatch Events for both New and Existing storage shall be informed by a reliable forecasting mechanism of PJM's Capacity 5CP and Transmission 1CP, which includes the PJM capacity and transmission peak hours, but shall not be limited to periods

expected to coincide with coincident peak hours and may also be called during distribution-level thermal constraints, local congestion, and other qualifying grid stress conditions as determined by EDCs. Participants enrolled in Block 1 shall not receive duplicative compensation from a separate program for the same service, system benefit, or performance for which they are already compensated under the Block 1 program, unless a participant enrolled in Block 1 elects to opt-out of the program.

Staff recommends the following primary objectives for Block 1:

1. Reduce system peak demand at the distribution level by incentivizing storage resources to reliably discharge during EDC Dispatch Events, which will help reduce future capacity and transmission obligations and inform future efforts to avoid distribution system investment, thereby accruing savings to all residential and small commercial customers;
2. Accelerate the deployment of up to 150 MW of new BTM energy storage capacity and make use of up to 100 MW of existing unutilized energy storage capacity;
3. Provide a long-term, performance-based revenue stream that rewards actual system performance and aligns customer and VPP Provider compensation with delivered grid value;
4. Gather operational and market data related to resource performance, customer participation, dispatch effectiveness, and program administration to inform future storage deployment opportunities and subsequent capacity blocks;
5. Quantify retail peak load reduction to establish the evidentiary foundation of metrics that measure savings to all ratepayers.

### iii. Program Roles and Responsibilities

Staff recommends that to be eligible to receive performance incentives in Block 1, a Host Customer must be eligible to take Basic Generation Service – Residential Small Commercial Pricing ("BGS-RSCP") supply, regardless of whether they receive BGS supply or obtain generation services from a TPS, subject to the rules on anti-double counting specified below. While customers served by municipal and cooperative utilities are not eligible to receive compensation through Block 1, Staff recommends that the Board consider participation pathways for municipal and cooperative utilities in future blocks or other storage programs. Front-of-the-meter resources shall not be eligible for Block 1. However, Staff recommends the Board consider future capacity blocks or other programs to support the development of FTM energy storage systems.

A Host Customer enrolled in Block 1 may elect to opt-out of the program and transition to any separate future VPP program at any time. In order to participate in Block 1, a Host Customer must be represented by a DER Provider. DER Providers submit Block 1 applications to the EDC and enroll resources on behalf of Host Customers, act as the administrative liaison to the EDC, receive and disburse incentive payments to Host Customers, and operate and dispatch storage resources in response to EDC Dispatch Events. For purposes of Block 1, a DER Provider that submits an application on behalf of a Host Customer shall be considered the "applicant" and, upon enrollment, the "participant." DER Providers must submit an application for each Host Customer seeking to enroll in the program; EDCs should develop application processes to enable DER Providers to submit batches of applications to increase application and enrollment processing efficiencies. References herein to an "applicant" or "participant" shall be deemed to refer to the DER Provider unless expressly stated otherwise.

Staff recommends that EDCs serve as the program administrators for Block 1 and be responsible for enrollment, implementation, and day-to-day administration within their respective service territories. Consistent with the straw proposal, Staff recommends that EDCs coordinate the dispatch of participating resources during likely PJM's Capacity 5CP and Transmission 1CP hours, distribution-level thermal constraints, local congestion, and other qualifying grid stress conditions, collectively referred to as EDC Dispatch Events. EDCs will also be responsible for tracking operational performance, calculating annual incentive payments based on verified performance, disbursing incentives through direct monetary payment to the DER Provider, facilitating timely interconnection, and filing appropriate tariffs and supporting documents for recovery of approved program costs. Additionally, EDCs will be responsible for presenting a plan outlining the types of distribution-level events they plan to call and how dispatch will be determined in real-time.

EDCs should identify the communication systems, metering processes, dispatch protocols, customer-facing procedures, and administrative capabilities necessary to implement Block 1 through a streamlined approach that minimizes administrative hurdles and avoids unnecessary or unreasonable costs on customers. EDCs should also describe how they will coordinate with Host Customers and DER Providers. A TPS may participate in Block 1 as a DER Provider. Any TPS participating in Block 1 shall demonstrate that neither it nor the participating resources are receiving duplicative compensation for the same capacity, transmission, demand-reduction, or other grid service through reductions in customers' peak load contributions ("PLC") or network service peak load contributions ("NSPLC") or another program. Staff recommends that the EDCs evaluate and provide recommendations regarding the need for a publicly available registry of DER Providers participating in the program, including whether such a registry should be administered by the EDCs, the Board, or another entity, and what eligibility, operational, consumer protection, and reporting requirements should apply. The EDCs should also assess whether elements of the DERA licensing framework under development in the Board's VPP proceeding may be appropriate for future adoption in this program.

DER Providers are the entities that apply and enroll the Block 1 resource in the program and operate and maintain eligible energy storage systems in accordance with program requirements. DER Providers will be responsible for maintaining operational readiness, satisfying applicable project milestones, providing data and documentation necessary for program administration, and operating their systems to discharge optimally during Performance Intervals in order to receive the performance incentives available under the program.

DER Providers, in coordination with EDCs, will be responsible for customer acquisition, enrollment support, customer education, and ongoing customer communications. Marketing and educational materials should describe the program structure, benefits, requirements, and participation obligations in clear and accurate language and should identify the appropriate point of contact for customers throughout enrollment and participation. The Block 1 program Straw Proposal contemplated a requirement that set minimum incentive passthrough requirements between DER Providers and Host Customers, expected to be not less than seventy percent (70%) of the incentive value. However, in light of differing ownership and operational models, Staff recommends removal of this requirement for the Block 1 program.

### iv. Eligibility: Operational Requirements and Development Maturity

Participating systems must be capable of measuring charge and discharge via the onboard energy storage meter, reporting interval meter data sufficient to evaluate performance during Performance Intervals, and supporting audit, verification, and compliance processes. Systems should be configured to enable accurate tracking of energy dispatch and performance outcomes

using time-synchronized interval data consistent with program verification protocols. Staff also recommends that EDCs identify appropriate cybersecurity standards, communication protocols, and data protection measures for dispatch, metering, and performance reporting.

If export-limiting configurations are elected by the interconnection applicant, EDCs shall ensure such resources are studied based on agreed-upon export capability rather than nameplate capacity in line with the intent of the Board's interconnection rules set forth at N.J.A.C. 14:8-5.1 through N.J.A.C. 14:8-5.13. Applicants should demonstrate sufficient development maturity at the time of application to ensure that reserved program capacity is likely to result in operational resources. At a minimum, applicants should provide evidence of an active and valid interconnection application and, where applicable, Host Customer authorization or other documentation granting the DER Provider the right to operate, control, and enroll the resource. New projects should achieve commercial operation within the timeframe established by the EDC and approved by the Board, anticipated to be no later than twelve months from the date of award, subject to approved extensions for circumstances beyond the applicant's reasonable control, such as an EDC failure to timely process interconnection.[28] To establish the twelve-month installation window, EDCs shall provide applicants with a dated Reservation Letter that confirms enrollment in the program and the Awarded Storage Capacity.

Staff recommends that eligibility for Block 1 incentives be limited to residential and small commercial BTM energy storage systems, defined specifically as those Host Customers eligible for BGS-RSCP, installed on the customer side of the utility meter and interconnected to an EDC distribution system. Participating resources shall not receive duplicative compensation for the same service, system benefit, or performance for which they are already compensated under the Block 1 program. A Block 1 participating resource may elect to opt-out of the program and transition to any separate future VPP program at any time as further described in Section D.vi.. Projects that enter into bilateral arrangements with a data center or other new large load for the same capacity shall be ineligible for a Block 1 incentive. Customers are eligible if they qualify for BGS-RSCP, regardless of whether or not they take default supply or contract with a TPS. Similarly, customers are ineligible for Block 1 participation if they are simultaneously enrolled in a Demand Response Resource, DERA, or other supply-side resource in the PJM wholesale markets that provides compensation for the same services compensated by Block 1, or impedes Block 1 resources from operating as reasonably expected by the program.

## v. BTM Energy Storage Exports and Net Energy Metering

Staff recommends that EDCs process interconnection requests from, and allow interconnection of, energy storage resources, whether standalone or paired with onsite solar,[29] that seek permission to export using the interconnection procedures prescribed in N.J.A.C. 14:8-5.1 through N.J.A.C. 14:8-5.13. EDCs shall also allow existing BTM storage resources, whether standalone or paired with onsite solar, to obtain permission to export by submitting new interconnection requests. EDCs should consider such a customer's existing and proposed export capacity in determining whether new studies are needed when processing such interconnection requests.[30]

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[28] Though Staff believes the program design must account for the possibility of EDC processing delays to avoid unfairly penalizing participants, Staff reiterates that one of the EDCs' primary responsibilities in implementing the Block 1 program is facilitating the timely enrollment and interconnection of BTM energy storage resources.

[29] For the purposes of this Order, "standalone storage" and "standalone storage system" refers to any energy storage system that is not paired with a generation source.

[30] See N.J.A.C. 14:8-5.1 ("'Export capacity' means the amount of power that can be transferred from a DER

EDCs should generally allow existing solar-plus-storage applicants to obtain permission to export without a new interconnection study if the applicant agrees to limit their export capacity to its current level and implement any necessary export controls, unless the EDC has specific reliability concerns that this would not address.

Existing and New Storage systems that are paired with an eligible net-metered solar facility may export energy and receive NEM credit provided that the storage system is configured through equipment controls or operating software to ensure any energy the storage system exports to the grid was charged exclusively from the paired solar facility (i.e., configured in "NEM integrity" mode). Existing solar-plus-storage Host Customers who lack permission to export energy from their storage component remain eligible for NEM rates regardless of whether their systems operate in "NEM Integrity" mode, unless they obtain new interconnection approval to export stored energy. Because to date EDCs have prohibited energy storage exports from storage-plus-solar systems, all exports from such existing systems originate from solar generation and remain eligible for NEM credits.

Until the Board reviews and approves tariffs that address exports from storage systems that are not eligible for NEM credit (e.g., exports from standalone storage systems, which do not charge from a Class 1 renewable energy source) or orders otherwise, the only state-level compensation for such storage exports shall be Block 1 payments. Note that such payments are based on energy discharged by the storage system rather than energy exported to the grid, so exports are only compensated to the extent they facilitate greater energy storage discharge during EDC Dispatch Events.

Staff further recommends that the Board direct EDCs to file revised tariffs to the extent that new tariffs are necessary to allow for exports from BTM energy storage systems and solar-plus-storage systems, and/or to provide NEM credits for kWh exports from energy storage systems that were exclusively charged from onsite solar generation. To the extent EDCs must specify a tariff compensation rate for the kWh a standalone energy storage system exports to the grid to enable exports, that tariff rate should be zero until such time as the Board directs EDCs to file revised tariffs that provide for a non-zero compensation rate on the basis of a more developed record. EDCs should file any such tariffs within sixty (60) days of the effective date of this Order.

### vi. Enable Front of the Meter Storage Interconnection Studies

To accelerate the timeline for FTM energy storage deployment in future capacity blocks, Staff recommends the Board direct Staff to develop recommended clarifications about how the Board's current interconnection rules apply to FTM energy storage facilities. Staff notes that the current lack of clarity about how present interconnection rules apply to FTM energy storage resources is inhibiting their interconnection, especially in the absence of a tariff governing FTM energy storage facilities. Staff also believes the Board should provide these clarifications in the near-term, so FTM storage interconnection studies can run in parallel to the process of developing FTM storage tariffs. In particular, Staff believes rule clarifications are needed regarding how EDCs should consider the proposed charging and discharging profiles of FTM energy storage facilities in interconnection studies.

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or customer-generator facility to the distribution system. Export capacity is either the nameplate rating, or a lower amount, if limited, using an acceptable means identified in this subchapter."); N.J.A.C. 14:8-5.2(l) ("If a customer-generator facility uses any configuration or operating mode at (*l*)2 below to limit the export of electrical power across the point of common coupling, then its export capacity shall be the maximum amount of power it can export when using the relevant configuration or operating mode . . . .").

Directing Staff to prepare these recommended clarifications supports the objectives of EO 2 to accelerate energy storage deployment. It would also advance New Jersey's statutory goal of deploying 2,000 MW of energy storage by 2030 pursuant to N.J.S.A. 48:3-87.8 and further develop the market that will eventually also utilize the long-term Grid Flexibility Services tariff described in this Order.

### vii. Capacity Allocation

Staff recommends that the 150 MW Block 1 target of New Storage capacity be allocated among the EDCs based on each EDC's share of total New Jersey residential sales. The proposed allocation is seventy-three (73) MW for PSE&G, fifty-two (52) MW for JCP&L, twenty-one (21) MW for ACE, and four (4) MW for RECO (Table 2). Staff further recommends that the Board authorize Staff to reevaluate and revise capacity allocations if necessary to facilitate enrollment of the full 150 MW of Block 1 Awarded Storage Capacity, including if one or more EDCs has available capacity while another EDC has eligible projects on a waitlist.

Staff recommends that the 100 MW of Existing Storage capacity be allocated among the EDCs based on each EDC's share of total New Jersey residential sales. The proposed allocation is forty-nine (49) MW for PSE&G, thirty-four (34) MW for JCP&L, fourteen (14) MW for ACE, and three (3) MW for RECO. As part of each EDC filing, Staff recommends that the EDCs include in their filings their own estimates of how much Existing Storage capacity can be enrolled in the program to the extent that these numbers conflict with the aforementioned allocations. Staff will evaluate EDC filings and make a final recommendation for the Board's review of the EDC filings on the capacity allocations for Existing Storage. If one or more EDCs have projects waiting to be enrolled, and at the same time one or more EDCs have not received sufficient complete applications to meet its/their respective capacity allocation(s), Staff may at their discretion revise the capacity allocation to facilitate the enrollment of 250 MW of Block 1 Awarded Storage Capacity.

**Table 2. Block 1 Total Capacity Allocation**

| EDC | Existing Storage Capacity Allocation (MW) | New Storage Capacity Allocation (MW) | Resulting Block 1 Capacity Allocation (MW) |
|---|---|---|---|
| PSE&G | 49 | 73 | 122 |
| JCP&L | 34 | 52 | 86 |
| ACE | 14 | 21 | 35 |
| RECO | 3 | 4 | 7 |
| **TOTAL** | **100** | **150** | **250** |

### viii. Enrollment Process

Staff recommends that EDCs conduct enrollment through an open, first-come, first-served process until Block 1 is fully subscribed or the Board determines that enrollment should be closed. Applications submitted during the same calendar week should be treated as submitted at the same time for purposes of enrollment priority. Provisional waitlist enrollment should continue after an EDC's capacity allocation is fully subscribed so that eligible projects may receive capacity if previously awarded projects withdraw, are disqualified, or additional capacity becomes available

through reallocation.

Each Applicant should submit to the EDC a complete Block 1 application package that includes: evidence of a submitted interconnection application, an attestation that any energy the storage system exports will only be stored solar energy sourced from an onsite solar array if the Applicant seeks NEM credit for storage exports, Host Customer details, data-sharing agreements, and any additional documentation necessary to verify eligibility and administer the program. As part of the Application package, each applicant should also submit a letter of intent, which shall memorialize the applicant's good faith intent to proceed with project development and to comply with all requirements of the Block 1 program, including any terms and conditions, upon being issued a Reservation Letter.

Each EDC's MFR filing shall identify the documents required for a complete Block 1 application package, including, at a minimum, evidence of a submitted interconnection application, an applicant-executed letter of intent, Host Customer authorization, confirmation of adherence to the customer terms and conditions, data-sharing agreements, and any additional documentation necessary to verify eligibility and administer the program. Application forms and process should be standardized across EDCs to the extent practicable and should be coordinated through the PowerUp NJ Working Group.

Staff recommends that each applicant submit a non-refundable $50 application fee with each Block 1 application. The fee is intended to recover a reasonable portion of EDC costs associated with application intake, completeness review, eligibility verification, queue administration, and issuance of reservation or provisional reservation letters, while discouraging speculative applications for scarce Block 1 capacity. Staff may revisit the application fee based on EDC implementation filings, actual application-processing costs, observed application volumes, and early experience with Block 1 enrollment.

Following successful completeness and eligibility review, the EDC should issue a Reservation Letter to the applicant identifying the Awarded Storage Capacity reserved for the applicant and the deadline by which the project must achieve commercial operation. Once an EDC's Block 1 allocation is fully subscribed, complete and eligible applications submitted in later weeks should receive a Provisional Reservation Letter placing the project on the waitlist. Upon project completion and verification that the system is installed, interconnected, operational, and capable of required data reporting and dispatch performance, the EDC should issue a Readiness Letter confirming the system is ready to participate in the Block 1 program.

For Existing Storage, enrollment should be a simplified process that verifies the existing resource and provides for quick enrollment of the devices.

### ix. Event Dispatch Protocol

EDC Dispatch Events are those EDC-directed discharge periods during which awarded resources are expected to discharge optimally and during which performance is evaluated. Staff recommends that EDCs direct their dispatch events to target likely PJM Capacity 5CP and EDC Transmission 1CP intervals and, to the extent possible, qualifying grid stress conditions.

The following are preliminary event parameters, which will be refined through the EDC filings in response to the MFRs established by this Order.

1. **Maximum event duration**: Three (3) hours per event
2. **Maximum number of events per season**: Twenty-five (25) events per summer season (June 1 - September 30), which aims to include the PJM Capacity 5CPs and

Transmission 1CP and five (5) events per winter season (December 1 - February 28), with a total of no more than thirty-five (35) EDC Dispatch Events per calendar year, inclusive of any events called outside the defined summer and winter windows (e.g., in response to an unplanned reliability need in the spring or fall months, test calls to ensure system readiness not included in this total count);

3. **Advance notice:** EDCs shall provide at least twenty-one (21) hours[31] advance notice of an EDC Dispatch Event. Each EDC shall demonstrate that its forecasting, communication, and dispatch process can use that notice period while maintaining a reasonable ability to target PJM coincident peak periods and other qualifying grid-stress conditions.

As with the VPP Interim program, an EDC may propose additional opportunities for Block 1 when supported by operational need or a demonstrated incremental ratepayer benefit, provided sufficient participant capability and protections. EDCs should test localized DER dispatch in order to gather data, gain team experience and lay the foundation for future infrastructure deferral via targeted VPP grid services. EDCs are encouraged to closely involve planning and operations teams in this testing.

### x. Performance Framework Mechanics

Staff recommends that annual incentive payments be based on verified performance during EDC Dispatch Events. Performance should be measured via energy storage device meter data during Performance Intervals, which are discrete hourly periods within an EDC Dispatch Event. The annual incentive payment should equal the incentive rate multiplied by Awarded Storage Capacity multiplied by the Performance Factor. The Performance Factor should measure actual discharge performance relative to Awarded Storage Capacity, so that resources that perform at 100 percent of Awarded Storage Capacity during Performance Intervals receive the full incentive value and resources that underperform receive proportionally reduced payments. Staff recognizes that, given the Program's performance framework and three (3)-hour maximum dispatch windows, achieving 100 percent performance during every EDC Dispatch Event is not reasonably achievable by many of the energy storage system models expected to enroll in Block 1. A more detailed explanation for how incentive payments are to be calculated can be found below in Attachment E. Applicants are expected to make their own judgment about what level of realized incentive payment is feasible considering the Program design, the incentive payment mechanism detailed in Attachment E, and their own resource configuration.

Incentive payments should be made annually after the end of each Performance Year and after verification of resource performance. The Performance Year should run from June 1 through May 31. Incentive payments should be disbursed no later than ninety (90) days following the end of the Performance Year. Projected incentive costs should be included for recovery through the applicable rider during the Performance Year in which the costs will be incurred, subject to annual reconciliation. EDCs should collect and validate performance data, calculate annual Performance Factors, share performance data and Performance Factor calculations with the DER Provider, administer incentive payments to DER Provider, establish procedures for incentive payment disputes, and report annually on the value created by Block 1 resources dispatched during EDC Dispatch Events.

Metrics recorded during periods in which a resource operates pursuant to mandatory EDC dispatch instructions that limit its ability to discharge should be excluded from standard

[31] Please note the Block 1 program does not include emergency events as contemplated in the VPP Interim Program. Emergency event notification only applies to the VPP Interim Program.

performance evaluation to the extent that the performance deviation results directly from compliance with those instructions.

### xi. Determined Incentive Level

Staff recommends an incentive rate of $200 per kW of Awarded Storage Capacity for New Storage, representing the maximum annual payment available to a project that achieves a 100 percent Performance Factor. To determine an appropriate incentive level Staff first undertook a gap analysis for a representative New Jersey residential energy storage system project and then evaluated comparable utility-dispatched, pay-for-performance energy storage programs in other jurisdictions. The gap analysis indicated an incentive level of approximately $300 per kW when considering project costs, financing assumptions, federal tax benefits, operations and maintenance costs, and time-of-use bill savings. Comparable state programs also indicate similar incentive levels.

However, Staff recommends setting the incentive below both the modeled revenue gap and comparable program benchmarks because residential energy storage systems provide Host Customer resiliency benefits that are not readily quantified and because some participants may realize greater bill savings than reflected in the statewide average. Staff concludes that a $200 per kW of Awarded Storage Capacity annual incentive is expected to provide a meaningful performance-based revenue stream that supports deployment and market development while balancing ratepayer protection, cost-effectiveness, and the Board's interest in preserving flexibility for future VPP and grid-flexibility compensation mechanisms.

Staff also recommends providing a $100 per kW of Awarded Storage Capacity incentive for Existing Storage. Staff recognizes that there are existing resources that can provide needed capacity to the grid and those should be compensated for the service they provide. Staff also recognizes that these resources did not require a financial inducement to install and should be provided with equitable compensation for the service they provide while at the same time being mindful of the impact that such incentives can have on other ratepayers.

Furthermore, Staff expects that the $200 per kW incentive will help drive new customers into the program and help establish a market while BPU Staff in cooperation with the GridFlex workgroup creates recommendations to establish the appropriate long-term compensation mechanism for storage assets.

### xii. Relationship to existing residential storage financing

Interest-free loans for residential storage currently offered under the Triennium programs may continue as a holdover within those programs. Where a loan requires the storage system to respond to utility dispatch events, that system is already compensated for peak demand reduction and is not eligible for Block 1 incentives while that obligation remains in effect. Each EDC shall identify in its filing any such loan program, the number of systems and kW enrolled, and when each dispatch obligation ends.

## D. PowerUp NJ Recommendations

### i. Program Budgets

Staff recommends a total budget of **$100 million for the VPP Interim Program**, allocated among the EDCs as shown in Table 3. The figure was derived by reviewing the existing DR budgets, the maturity of the existing DR programs in each territory, the EDC's own comments on anticipated

budgets, and other stakeholder comments on comparative budgets. Block 1 carries its own budget, which is not included in Table 3.

The allocation starts from each EDC's share of the Summer 2025 weather-normalized coincident peak (Table 1) and adjusts for the extent of program infrastructure already in place. PSE&G and JCP&L have operational VPP pilot and DR programs which have led to a larger starting customer base and therefore require less start-up investment per unit of load under management than an EDC building comparable capability from a smaller base. ACE and RECO are allocated a higher proportional budget than their share of peak 1) in order to cover additional start-up costs needed to quickly enable adoption, and 2) in recognition that smaller territories may not be able to spread fixed platform and integration costs across a comparable volume of load.

**Table 3. VPP Interim Program Budgets**

| EDC | VPP Interim budget (2027–2029) |
|---|---|
| PSE&G | $50 million |
| JCP&L | $25 million |
| ACE | $22 million |
| RECO | $3 million |
| **TOTAL** | **$100 million** |

These budgets serve as guidance in shaping the programs rather than as fixed allocations. Each EDC shall provide a detailed written narrative for its proposed budget in its filing. An EDC proposing a budget that deviates by more than 15% from the amount shown in Table 3 shall also provide a detailed written justification for the deviation in its filing.

The program costs for Block 1 are set forth separately below in nominal dollars and are additional to the amounts in Table 3. The budget assumes an incentive payout in accordance with BCA assumptions, including a phased in deployment and an estimated non-perfect performance factor. To be clear, the budgets shown in Table 4 assume estimated incentive payments based on a reasonable participant's average performance, rather than assuming perfect performance that is unlikely to be achieved in practice. It also assumes a per-project administrative cost consistent with EDC submissions in Triennium filings.

**Table 4. Block 1 Program Budgets**

| EDC | Block 1 Budget (2027–2029) | Block 1 Budget (2030–2039) |
|---|---|---|
| PSE&G | $14.1 million | $107 million |
| JCP&L | $9.9 million | $75.8 million |
| ACE | $4.1 million | $31.5 million |
| RECO | $0.74 million | $5.6 million |
| **TOTAL** | **$29 million** | **$220.6 million** |

## ii. Cost Recovery

Both the VPP Interim Program and Block 1 Program are designed to lower costs through avoided infrastructure buildout and reduced capacity procurement. Careful attention must be paid to how program costs are recovered so that these programs drive savings for ratepayers rather than add to ratepayers' cost burden.

Staff recommends that prudently incurred costs of the PowerUp NJ Program be recovered through each EDC's tariff where costs related to programs approved under N.J.S.A. 48:3-98.1 and the program-specific statutory authorities described later in this Order are recovered. For ratemaking, budgeting, and reporting purposes, program costs shall be treated as operating expenses unless the Board expressly approves a demonstrated capital investment or other deferred investment necessary to implement the program. The need for capital investments and proposed recovery treatment must be included and described in each EDC's petition proposing its VPP Interim and Block 1 program designs. Application fee revenues collected under Block 1 shall be credited against recoverable Block 1 administrative costs. Each EDC shall demonstrate that costs proposed for recovery are not already recovered through base rates, existing program rider, or another recovery mechanism.

Staff recommends that each EDC be required to identify the timing of projected program costs and expected ratepayer benefits in their filings. As part of each filing, EDCs should propose a recovery schedule designed to recover incurred operating expenses and customer incentive payments in the Performance Year those amounts are paid, subject to an annual prudence review, as well as annual reconciliation of actual expenditures and revenues. To the extent that capital investments are required, the filing shall provide a separate recovery schedule that identifies any proposed deferral, amortization period, and/or carrying costs.

Staff recognizes that the benefits associated with both the VPP Interim and Block 1 programs, including avoided capacity, transmission, and distribution costs, may not accrue contemporaneously with program expenditures. Such timing differences are common for privately financed infrastructure installations and demand-side investments. A lag between program expenditures and benefit realization shall not by itself justify carrying charges. Any carrying charges shall reflect actual under- or over-recovered balances due to EDCs not being guaranteed earnings under this Order. Accordingly, Staff recommends that each EDC provide a year-by-year showing of projected benefits, revenue requirement impacts, and bill impacts, including the timing by which savings are expected to flow through to customers. Additionally, for Block 1, Staff recommends that the EDC's petitions due on February 12, 2027 shall include expected revenue requirements for Performance Year 1 of the program, to ensure recovery of those projected costs can begin as soon as the program is open for enrollment (i.e. sixty (60) days from the approving order) and so that true up can occur in Performance Year 2. The same revenue requirements for Year 1 shall also be included in the applicable 2027/2028 cost recovery filing.

For clarity, "Operating Expense" as used in this Order is intended to be the single cost recovery treatment applicable to these program costs, including customer incentives, except for any capital investment the Board expressly approves as described above. Potential Operating Expenses for this program include:

1. the costs of operating the programs, including EDC staff time and contracted implementation contractors;
2. procurement of vendors, VPP Providers, and DERMS Providers;[32]

[32] For purposes of Block 1, DER Providers are not eligible to receive reimbursement by EDCs for costs associated with their participation in the Program.

3. evaluation, measurement, and verification, including the independent verification described above;
4. marketing, customer outreach, education, and enrollment; and
5. customer incentives, including enrollment payments, performance-based payments, and storage incentives.

The five (5) budget categories used in the EDCs' existing EE and DR filings – program administration and implementation, customer incentives, EM&V, marketing, and other – survive for budgeting and reporting purposes as sub-categories beneath Operating Expense. They are not separate recovery categories. Customer incentives in particular are a sub-category of Operating Expense and are not separately capitalized or amortized.

Recovery of Operating Expense is subject to a prudence standard. Each EDC shall provide sufficient supporting documentation to demonstrate that costs proposed for recovery are reasonable, necessary, and properly allocated to the program, including explanations of variances between approved budgets and actual expenditures. The Board retains the authority to review and disallow costs determined to be imprudent, unsupported, or duplicative.

Staff recognizes that a performance incentive or shared-savings mechanism, under which an EDC could earn a share of the verified system savings its programs deliver, can be an important tool for tying utility earnings to results rather than spending. Staff does not recommend establishing a performance incentive or shared-savings mechanism in this Order. The initial program period should instead establish reliable baselines for program performance, avoided costs, ratepayer savings, and EDC implementation responsibilities. Following the VPP Interim Program Midterm review and Block 1 Interim Report, Staff recommends an evaluation of potential performance incentives and/or shared-savings mechanism under which EDC earnings would depend on independently verified savings or performance above the minimum requirements established by the Board. Staff recommends that the evaluation for both VPP Interim Program and Block 1 consider cumulative program performance and/or savings generated since the programs' launch.

Staff recommends that costs be allocated via a uniform charge applicable to all customer classes for the following reasons. First, Staff anticipates transmission savings as well as modest distribution system savings will provide benefits to all ratepayers. Second, both programs can help reduce overall costs for electricity customers by reducing usage of electricity from the grid at times of peak demand, when wholesale electricity prices are highest, as well as reduce wholesale prices themselves via demand reduction induced price effect (DRIPE). Finally, Staff recommends the consideration of cost and benefit allocation at the GSESP portfolio level. While Block 1 is structured as a program for the BGS-RSCP class, Staff anticipates future capacity block allocations under GSESP that would directly benefit commercial and industrial customers, as described in the Storage Straw Proposal.

### iii. Benefit Cost Analysis ("BCA")

Consistent with the approach taken for EE and DR programs implemented under the Clean Energy Act of 2018 ("CEA"), Staff recommends that benefits of the VPP Interim Program be evaluated as an EE and conservation program under N.J.S.A. 48:3-98.1. Though the Board's authority to proceed with the Block 1 program is not based on N.J.S.A. 48:3-98.1, Staff recommends the Board adapt the basic benefit-cost evaluation framework the Board originally developed for N.J.S.A. 48:3-98.1 for the Block 1 program as well. Historically, programs implemented under N.J.S.A. 48:3-98.1 have been reviewed against six (6) benefit-cost tests

containing measures specific to EE programs: the Ratepayer Impact Measure ("RIM"), Total Resource Cost ("TRC"), Societal Cost Test ("SCT"), Program Administrator Cost Test ("PACT"), Participant Cost Test ("PCT"), and New Jersey Cost Test ("NJCT"). Due to the fact that the PowerUp NJ Program focuses on resources that differ from the traditional EE resources these tests were designed for, Staff believes that a modified evaluation framework is warranted. Building upon the existing EE framework and its six (6) benefit-cost tests, Staff proposes that EDCs perform modified versions of these tests to account for the unique characteristics of the resources the PowerUp NJ Program will support. Staff recommends that for purposes of the assessments described herein, the portfolio assessment be conducted at the component level, such that the EDCs' VPP Interim programs are assessed as a portfolio and Block 1 is assessed as a separate portfolio. Furthermore, VPP Interim and GSESP programs each have certain operational traits that will warrant different assumptions within their own tests. This distinction reflects the nature of the underlying resources: the VPP Interim Program includes resources that may affect customer comfort or operations, such as smart thermostats and load curtailment, while the GSESP program is focused on energy storage systems, which generally do not affect customer comfort or operation but require charge and discharge management. Therefore, Staff recommends the EDCs conduct the six (6) cost tests for each component program as part of their filings proposing their VPP Interim and Block 1 programs, as well as during subsequent reporting, or provide a corresponding justification why a specific test does not apply.

Staff has determined that the objectives of this Order, particularly insofar as it is meant to effectuate the objectives of EO 1 and EO 2, are most directly evaluated through the RIM test and therefore recommends that the RIM test at the portfolio level serve as the primary focus of the BCA. As the New Jersey Legislature recognized in the similar context of the CEA's EE programs, it can be appropriate to include a subprogram with "a benefit-to-cost ratio of less than 1.0" in a portfolio if its implementation "is in the public interest" provided the overall portfolio has a benefit-to-cost ratio that is greater than or equal to 1.0[33] The remaining tests will serve as supplementary metrics to inform a broader assessment of portfolio performance, ratepayer impacts, and overall policy value.

Staff advises that EDCs follow the cost test methodologies and assumptions for each subprogram to evaluate, independent from Staff's internal analysis, the Benefit Cost Ratios ("BCRs") for each respective test. The respective methodologies and assumptions are detailed in Attachments F for the VPP Interim Program and Attachment G for the Block 1 Program. Certain assumptions have been prescribed by Staff based on publicly available information and determinations based on program design. For other assumptions, Staff has provided assumed values that EDCs may propose to modify where they are better positioned to develop more accurate estimates, subject to reasonable justification. Staff also recommends that the PowerUp NJ working group assess, and if deemed appropriate, develop the methodology and assumptions for a combined BCA evaluating the effectiveness of collective PowerUp NJ Program after its launch.

In support of this Order, Staff completed a RIM test for the VPP Interim Program and Block 1. The results of Staff's RIM test for Block 1 can be found in Attachment H. As described therein, Staff found that BTM storage and aggregated BTM DERs dispatched during peak and grid-stress conditions can provide net benefits to ratepayers. Specifically, Staff found a BCR of 1.98 associated with Block 1 and a BCR of 1.16 associated with the VPP Interim Program.

In addition to the six (6) BCA cost tests above, Staff recommends that the EDCs conduct a bill impact analysis to determine program impacts on residential, commercial, and industrial

[33] N.J.S.A. 48:3-87.9(d)(2).

customers.

### iv. Working Group

Staff recommends that a PowerUp NJ Working Group be established to facilitate collaboration between Staff, EDCs, Rate Counsel and relevant stakeholders. Subgroups, including but not limited to the Marketing, EM&V, and benefit-cost analysis subgroups referenced in this Order, may be organized to address specific workstreams.

### v. Branding, Marketing, and Public Education

Staff recommends that the Board direct Staff to establish a logo and branding standard for PowerUp NJ and share it with the EDCs. Staff also recommends that the Marketing subgroup of the PowerUp NJ Working Group coordinate marketing efforts with the EDCs.

Staff further recommends that Staff work with stakeholders to launch public education and marketing campaigns on PowerUp NJ before the programs open, so ratepayers understand how the programs lower energy costs for both participants and other ratepayers.

### vi. Transition Between VPP Interim and Block 1 Programs

Staff recommends that a single device shall not be enrolled in both the VPP Interim Program and Block 1 at the same time. A Host Customer may enroll an energy storage system in Block 1 and other devices at the same Site (e.g., smart thermostat, EV charger) in the VPP Interim Program only through DER Providers, as provided in Section II.A.iii. A Host Customer may leave either program at any time without an early-exit penalty and enroll the same device in another program, including a successor program, subject to program availability and satisfaction of requirements. Staff acknowledges the clarity required to facilitate a transitional framework between future programs, while also acknowledging that the absence of those program design structures presently limits the level of detail with which transitional rules can be established. More formal transition provisions will be developed as future program design parameters become defined. While it is both plausible and desirable that PowerUp NJ resources be eligible to provide and be compensated for distinct services under future compensation frameworks, it is also possible that some resources may elect, or be required, to transition fully from their respective PowerUp NJ program into a successor program. In such circumstances, a PowerUp NJ participant would forfeit any remaining PowerUp NJ compensation opportunities, but would not be subject to clawbacks of incentive payments already earned. The resource's MW value would be removed from PowerUp NJ capacity accounting and would be eligible to re-enroll at a future date only to the extent that subsequent incremental block capacity is available. Where full transitional disenrollment is not required and simultaneous program participation is permitted, PowerUp NJ resources would remain subject to all applicable PowerUp NJ program requirements, including, but not limited to, restrictions on participation as supply-side resources in PJM wholesale markets and any other structure that would impede a resource from operating as reasonably expected by the program.

### vii. Anti-Double-Counting

Load reduction that is compensated under Block 1, or under a Triennium program, may not simultaneously be counted toward the VPP Interim Program peak demand reduction target or included in the savings base on which performance earnings for the VPP Interim Program are calculated, and vice versa. Neither can any energy storage asset participating in Block 1 participate in PJM wholesale markets as either an individual resource or as part of a DERA. Each

EDC shall describe in its filing the contractual and systems controls that give effect to these limitations.

Participation in Block 1 does not create an entitlement to receive additional compensation for the same capacity value, transmission value, distribution value, demand reduction, or performance obligation through another Board-approved program. To the extent future compensation pathways are established, participants shall be required to comply with all Board-approved anti-duplication requirements then in effect.

### viii. Peak Demand Reduction and Cost Savings

Staff recommends an overall peak demand reduction goal for the PowerUp NJ Program of **three and one half percent (3.5%)** of service-territory peak load, of which the VPP Interim Program is to contribute **no less than three percent (3%)** and Block 1 is to contribute the balance. Each EDC shall propose a peak demand reduction target, expressed in MW, for all subsequent years. Table 5 presents Staff's reference values, derived from PJM Summer 2025 Weather Normalized RTO Coincident Peak data.

Staff has made this recommendation after looking closely at the existing resources that have been funded through EE incentives and the current EV programs as described above and believes that by enrolling significant portions of those customers in a VPP the goals can be quickly met. The identified resources do not include the many additional resources that have not been paid for through EDC or BPU incentives and the number of anticipated additional devices that will use EE or EV incentives paired with the opportunity for VPP participation that will come online in the next two years.

**Table 5. VPP Interim Peak Demand Reduction Reference Values by EDC**

| EDC | Summer 2025 Weather Normalized RTO Coincident Peak (MW) | 3% – VPP Interim (MW) | 3.5% – PowerUp NJ (MW) |
|---|---|---|---|
| PSE&G | 9,770 | 293.1 | 341.95 |
| JCP&L | 5,760 | 172.8 | 201.60 |
| ACE | 2,315 | 69.5 | 81.03 |
| RECO | 390 | 11.7 | 13.65 |
| **TOTAL** | **18,235** | **547.1** | **638.23** |

In addition to the peak demand reduction target, each EDC shall propose cost savings goals and measurements derived from VPP participation, covering Host Customer savings, avoided transmission and distribution costs, avoided capacity costs, and avoided energy costs, and shall express total cost reduction relative to the counterfactual in nominal terms and as an impact on residential rates.

The GSESP contribution to the PowerUp NJ peak shaving target will vary based on certain enrollment factors, both in and outside of EDC control. Those largely outside of EDC control include enrollment based on available incentives, the duration of participating systems (that is,

the ratio of the maximum amount of energy a storage system can store in kWh to its nameplate power capacity in kW), and participant response to EDC Dispatch Events. Within EDC control is enrollment as it relates to the processing of applications and review of interconnection requests, as well as the accuracy of scheduled EDC Dispatch Events in intersecting coincident peaks. The effect of these varied factors is that the enrolled nameplate capacity in kW of storage devices in the program does not translate 1:1 to kW of peak reduction. To account for this, Staff has derived a nameplate adjustment mechanism to translate program goals to realistic peak shaving, titled "Nameplate Capacity to Peak Shave Factor" ("NCPSF"), which will set high and low bounds for anticipated peak shaving. The low end NCPSF is determined to be thirty-two percent (32%) and the high end is sixty-five percent (65%). Reference Table 6 for how this translates into peak shaving MW targets.

Note that allocations of existing resources are assumed to be similarly split in load ratio share as with new resources, even though deployment data is not known at this point. Targets may be adjusted accordingly as existing resource enrollment data becomes available.

The EDCs shall design the quantitative performance indicators ("QPIs") as required under the MFRs such that they are directly aligned with, and measure progress toward, the peak-shaving targets described in this section.

**Table 6. Block 1 Peak Demand Reduction Reference Values by EDC**

| **EDC** | **Summer 2025 Weather Normalized RTO Coincident Peak (MW)** *MW* | **EDC Program Target MW** *Nameplate MW* | **Peak Shaving Target (Low)** *MW * **0.32*** | *%* | **Peak Shaving Target (High)** *MW* ** **0.65*** | *%* |
|---|---|---|---|---|---|---|
| PSE&G | 9,770 | 122 | 39.0 | 0.40% | 79.3 | 0.81% |
| JCP&L | 5,760 | 86 | 27.5 | 0.48% | 55.9 | 0.97% |
| ACE | 2,315 | 36 | 11.5 | 0.50% | 23.4 | 1.01% |
| RECO | 390 | 6 | 1.9 | 0.49% | 3.9 | 1.00% |
| **NJ** | **18,235** | **250** | **80.0** | **0.44%** | **162.5** | **0.89%** |

## ix. Program Approval and Post-Approval Review

Staff recommends that where an EDC's approved filing does not contain the full operational detail of a proposed subprogram within the VPP Interim Program – including its incentive levels, dispatch and enrollment procedures, VPP Provider contracting arrangements, and measurement approach – the EDC shall provide Staff with those details before launching the subprogram, and shall not launch such a subprogram until Staff has reviewed those details to ensure they are consistent with the program design approved by the Board. Staff recommends that this obligation

be stated in the Board's order approving each EDC petition, that the authority to provide approval be delegated by the Board to Staff, and that each EDC identify in its filing any element it expects to develop after approval.

This requirement responds to experience under the Triennium 2 DR programs, in which programs were approved on the basis of filings that did not describe how the programs would operate, and in which the resulting deployment fell short of what the approved budgets contemplated. It is not a second approval proceeding. It is a check that the program the EDC builds is the program the Board approved.

### x. Peak Shaving Adjustment ("PSA") Reporting and Coordination with PJM on PowerUp NJ Program Impact on PJM Zonal Load Forecasts

In order for peak reduction programs to result in capacity cost savings, the program must be reported to PJM and incorporated into its load forecast. For the VPP Interim Program, this can be achieved by having the EDC submit a PSA plan to PJM in the September prior to the summer season for which [34] be active. PJM will use the information submitted pursuant to this PSA plan to determine the appropriate adjustments to zonal peak load forecasts and the resulting reductions in capacity purchase obligations. New Jersey has not availed itself of this mechanism for its demand response programs, in part because the programs have lacked the defined dispatch parameters, measurement methodology, and forecast load reduction that such a plan requires.

This Order supplies those broad parameters. Staff therefore recommends that each EDC be required to describe in its filing how it will report a PSA plan to PJM for the load reduction its VPP Interim Program is forecast to deliver, how it will share the submitted PSA plan to the Board while respecting the confidentiality of customer-specific data, and to identify any impediment to doing so. Reducing the zonal capacity obligation creates direct and measurable savings to all ratepayers in the zone, not only to program participants, and is among the principal reasons these programs are cost-effective.

Staff recommends that each EDC be required to submit a PSA plan, or its successor, to PJM by September 10 of each year, beginning in 2027. The PSA plan must comply with PJM Manual 19 and any other applicable rules. If PJM sets an earlier deadline for that year, the utility shall meet PJM's deadline instead. If PJM changes its deadline, the utility shall notify the Board in writing within ten (10) business days of the change. The EDC shall also submit the same copy of the PSA plan to the Board when submit its plan to PJM. That initial PSA may be based on the demand response and VPP Pilot programs approved under the Triennium, as well as projected enrollment of approved VPP Interim and Block 1 programs.

Staff understands that there are barriers to including storage in a PSA plan absent changes to PJM's Open Access Transmission Tariff and potentially other governing documents that would require FERC approval. Most notably, there is currently no method by which the zonal load reductions provided by BTM storage exports can be captured in a PSA plan. Consequently, the current PSA mechanism would significantly underestimate the total peak reduction potential of Block 1 BTM storage resources. However, PJM annually solicits information about state distributed storage programs from state utility commissions such as the Board, so it can reflect such programs' impacts in its annual load forecasts and ultimately reduce zonal capacity obligations. As such, Staff recommends that the Board direct Staff to annually provide PJM with data about projected Block 1 storage deployment, as well as actual enrollment, interconnection,

[34] PJM Manual 19, Attachment D.

and deployment data to the extent it is available, to ensure that the Block 1 program also affects PJM's load forecast. Staff further recommends that the Board direct the EDCs to provide any assistance or data Staff needs to prepare the necessary information for transmittal to PJM. Staff further recommends that the Board retain the authority to direct the EDCs to transition their Block 1 programs into PSA plans or similar structures if and when amendments are made to PJM's governing documents that render such pathways viable for BTM storage.

To meet PJM's PSA plan requirements, each EDC may set PSA-specific dispatch parameters, including the temperature-humidity index trigger, event hours, and notification process, provided the parameters stay within the event limits in this Order or are justified in the EDC's filing. Each EDC shall submit a PSA for the portion of its VPP Interim Program that can meet PJM requirements and shall identify any barriers to including the rest. The EDC shall prioritize dispatch based on what will provide the most immediate ratepayers savings in the VPP Interim Program. The EDCs should describe their approach and dispatch methodology in their filings and prioritize dispatch in accordance with the approved filing.

## xi. Minimum Filing Requirements ("MFR")

Staff recommends that each EDC be required to file a petition proposing its PowerUp NJ Program no later than February 12, 2027. The MFRs for the VPP Interim Program are set forth in Attachment A and the MFRs for Block 1 are set forth in Attachment B, each of which Staff recommends the Board adopt. The two Attachments specify the required program description, targets, delivery and procurement showings, budget and cost forecasts, benefit-cost analysis, EM&V, QPIs, cost recovery showings, and reporting plan for each respective program. Tables A-1 and A-2 in Attachment A set forth the benefit and cost line items to be used in the benefit-cost analysis for the VPP Interim Program. Tables B-1 and B-2 in Attachment B set forth the benefit and cost line items while Attachment G provides the assumptions to be used in the benefit-cost analysis for the Block 1 program.

## xii. Reporting

### *1. VPP Interim*

Staff recommends that each EDC file three reports for the VPP Interim Program: a public Quarterly Report, a confidential Event-Level Report, and a public Annual Report. Each report shall measure the EDC's performance against the QPIs approved under Attachment A, Section VII. For these reports, Year 1 is the first performance year, and Year 2 is the second performance year, as "performance year" is defined in Attachment A. For example, if an EDC's first VPP Interim sub-program becomes operational on October 1, 2027, Year 1 runs from October 1, 2027, through September 30, 2028, and Year 2 runs from October 1, 2028, through September 30, 2029. The VPP Interim performance year differs from the Block 1 Performance Year described below.

**a. Quarterly Report (public).**

Each EDC shall file a Quarterly Report no later than forty-five (45) days after the end of each calendar quarter. The report shall include:

1. enrollment progress, including the number of enrolled customer accounts and devices and the MW of load under management as defined in Attachment A, Section VII(b)(iii), by DER type;
2. spending by Operating Expense sub-category, for the quarter and cumulative for the performance year, compared to budget;

3. the number of EDC Dispatch Events called, by event type (standard, grid stress, test, and any other type defined in the EDC's approved filing);
4. for each EDC Dispatch Event in the quarter, the event date and duration, aggregate MW dispatched versus MW delivered, the event response rate, and the customer opt-out rate, reported without customer-specific or VPP Provider-specific information; and
5. enabling systems milestones, such as the dispatch platform or DERMS, and contracting milestones, such as VPP Provider contracts executed.

An EDC may report results for events that have not yet settled as preliminary and update them in the next Quarterly Report.

**b. Event-Level Report (confidential, Board and EDC only)**

On the same day it files each Quarterly Report, each EDC shall submit an Event-Level Report covering each EDC Dispatch Event in that quarter. For each event, the report shall include:

1. the event date, start and end times, notice provided, event type, event location, and the system condition that triggered the event;
2. MW dispatched versus MW delivered, by VPP Provider and by DER type;
3. the number of customer opt-outs and of devices that did not respond; and
4. settlement data, including payments to each VPP Provider, for events settled during the quarter.

**c. Annual Report (public)**

Each EDC shall file an Annual Report no later than two months after the end of each performance year. The Year 1 Annual Report is due no later than November 30, 2028, and also serves as the Midterm Report on which the Midterm Review is based. The Year 2 Annual Report is due no later than November 30, 2029. The Annual Report shall include:

1. the benefit-to-cost ratio ("BCR") under each of the six cost tests, using actual costs and verified savings, for the performance year and cumulative to date;
2. verified net savings, showing each benefit line item in Table A-1 and each cost line item in Table A-2 of Attachment A;
3. results for each approved QPI, compared to the forecast and, where a target applies, to the target;
4. enrollment trends, including new enrollments, unenrollments, and the customer retention rate, meaning the percentage of customer accounts enrolled at the start of the performance year that remain enrolled at its end;
5. actual spending by Operating Expense sub-category, compared to budget;
6. performance during the 5CP and 1CP hours, including the verified load reduction in each 5CP and 1CP hour, the average calculated under Attachment A, Section VII(b)(iv), opt-out rates, the baseline used, and how actual load compared with that baseline;
7. how and when capacity and transmission savings flow through to BGS rates, updated for the performance year;
8. any PSA plan submitted to PJM during the performance year and the PJM delivery year it covers, compared with the verified load reduction, with customer-specific data treated as

confidential, or, if no PSA plan was submitted, the reason;

9. the VPP Provider contract disclosures required by Attachment A, Section II(a)(xiv), including actual customer pass-through measured against the non-binding passthrough goal;
10. a review of program effectiveness that identifies, with supporting data, any program element that is not meeting its QPI targets, peak demand reduction target, or cost savings target;
11. the reasons for any material difference between forecast and actual results for verified savings, peak demand reduction, and spending;
12. the EDC's improvement plan, including any program changes it proposes for the following performance year or, in the Year 2 Annual Report, any recommendations for a program extension or the long-term VPP framework; and
13. How the EDC's program has implemented all requirements of the program outlined in the MFRs and this Order and progress towards program goals.

Where the independent evaluator's verified results are not yet available, the EDC shall report its own estimates, labeled preliminary, and update them in the next report.

***2. Block 1***

**a. Annual Report**

Staff recommends that the Board require EDCs to prepare an Annual Report, detailing the QPIs required by the MFRs in Attachment B and Reporting Metrics required below. Annual Reports shall be due ninety (90) days following the conclusion of each Performance Year, which is defined as the period beginning June 1 and ending May 31 of the following calendar year. Annual Reports shall be required for the duration of the Program, that is, for as long as incentive payments for Block 1 are being made. Annual Reports shall also be used to inform the Boards ongoing program evaluation as detailed in the Interim Report Section of this Order.

The Annual Report should provide Staff with the following Reporting Metrics:

1. Program Enrollment and Uptake
    i. Applications received, approved, withdrawn, denied and waitlisted
    ii. Number of opt-outs from the Block 1 program
    iii. Average application processing time
    iv. Breakout of enrolled participation according to TPS vs. BGS supply arrangements, and participants on time of use rates
    v. Count of total unique DER Providers participating in the program
2. Interconnection
    i. Average interconnection processing time
    ii. Number of applications in the interconnection queue
3. Fleet Reporting
    i. Awarded Storage Capacity from new systems, both cumulative total and total awarded for the current Performance Year
    ii. Awarded Storage Capacity from existing systems, both cumulative total and total awarded for the current Performance Year
    iii. Total operational nameplate power capacity (kW) and energy storage capacity (kWh)

characteristics
iv. Location (zip code, circuit ID or similar) of enrolled systems
v. Number of systems configured as solar plus storage
vi. Dollar value of incentive payments made in the performance year

4. The peak reduction contribution of Block 1 dispatch to each of PJM's 5CP and 1CP events
5. A narrative of other relevant grid stress events addressed through Block 1 EDC Dispatch Events
6. EDC Dispatch Event report out
    i. Program expenditures broken out by category
    ii. Revenue requirement impacts
    iii. Customer bill impacts
    iv. Expected avoided capacity and transmission costs, as well as distribution benefits
    v. The anticipated timing by which such benefits are expected to be reflected in customer rates or bills
    vi. Any proposed mechanisms intended to reconcile or mitigate timing differences between program costs and customer benefit realization
    vii. Expected spending, broken out by administrative expense sub-category
    viii. actual spending broken out by administrative expense sub-category

7. Program Savings & BCA
    i. Estimated and realized distribution system benefits
    ii. Estimated and realized bill impacts attributable to program participation

**b. Preliminary Report**

To inform the Board's inputs to PJM's distributed storage load forecast adjustment, Staff recommends that EDCs shall submit a Preliminary Report, no later than thirty (30) days from after the end of a Performance Year. The Preliminary Report shall contain the previous Performance Year's enrollment of existing and new capacity into Block 1. The previous Performance Year estimates may be finalized and confirmed in the Annual Report. Additionally, the Preliminary Report shall contain projections for enrollment of new and existing capacity into Block 1 for the upcoming Program Year. If known, an estimate of the peak reduction achieved shall also be provided.

**c. Interim Report**

Based on annual reporting data provided by EDCs, Staff plans to undertake a comprehensive program evaluation after the completion of two Performance Years and report this as part of an Interim Report. The Interim Report should evaluate the minimum following elements and make recommendations regarding the modification and/or expansion of Block 1:

1. The extent to which enrolled participants are on TPS pass-through tariffs
2. Patterns and performance of EDC Dispatch Events across EDCs including actual dispatch events called during the reporting period, including events associated with PJM's Capacity 5CP and Transmission 1CP, and other distribution-level events
3. Participants' Performance Factors and realized revenues relative to the theoretical maximum
4. Program capacity size (including information on number and size of installed devices) and incentive levels

5. Application fee levels and necessity
6. The state of Load Forecast methodology at PJM as an effective savings mechanism and whether dispatch requirements and/or the manner in which the load reductions resulting from Block 1 are reported to PJM should be amended to increase savings opportunities
7. Program participation and uptake, including applications received, approved, withdrawn, denied and waitlisted, as well as awarded and operational storage capacity
8. Actual peak demand reduction achieved, compared to the target, and compared to the enrolled storage nameplate capacity
9. Actual spending by Operating Expense sub-category, compared to budget
10. Number of enrolled participants that have solar-plus-storage systems
11. Whether establishing an aggregator registry is necessary or desirable
12. Benefit Cost Analyses

## xiii. Continued Coordination

### ***1. Long-Term VPP Program Framework***

Although Staff recommends that the Board not require deployment of EDC-operated DERMS as a prerequisite to VPP Interim or Block 1 program implementation, Staff expects that enhanced distributed energy resource management capabilities will likely be necessary to support future grid-flexibility services, locational dispatch, advanced distribution planning, and an open-access VPP framework. While the VPP Interim and Block 1 Programs are designed as EDC-administered bridges, Staff recommends that the long-term framework be market-based and tariff-governed: any Board-licensed DER Aggregator would be able to participate on non-discriminatory terms, distribution services would be compensated through a tariff developed with input from the GridFlex workgroup, and DERAs would be positioned to participate competitively in PJM wholesale markets.[35] Staff anticipates that over the next thirty (30) months, while the EDCs develop and administer the interim program, the EDCs will also work with Staff to:

1. develop and receive approval for EDC-specific PSUPs;
2. develop and receive approval for a petition to create a compensation tariff for distribution-level service architecture and compensation;
3. develop a plan to establish advanced DERMS capabilities; and
4. participate in a public stakeholder process to discuss the results of the VPP Interim Program Midterm Review.

### ***2. Market Support Structures***

The VPP Straw Proposal described the market support structures necessary for both program phases. Staff anticipates stakeholder engagement on the following elements over the next thirty (30) months through the PowerUp NJ Working Group established by this Order:

1. **DER Registry:** DER registries with a consistent structure across EDCs, containing common data fields and definitions, to enable enrollment, prevent double counting across compensation streams, and support grid reliability;

[35] VPP Straw Proposal, Section 3; see also Sections 3.1 through 3.8.

2. **DER Aggregator Licensing and Code of Conduct:** a Board-administered licensing framework with annual licenses aligned to wholesale market timelines; application requirements addressing financial viability, technical capability, customer service, and data privacy and cybersecurity compliance; a code of conduct governing required disclosures, prohibited sales and enrollment practices, limitations on opt-out penalties, and customer data usage restrictions; and Board authority to suspend or revoke licenses;
3. **Cybersecurity:** discussion of cybersecurity and data-protection obligations of the Board, EDCs, VPP Providers, DER Aggregators, OEMs, DERMS Providers, and Host Customers; a three-tier data-access structure covering enrollment data, interval meter data, and real-time dispatch data; baseline required standards including IEEE 1547.3-2023, and the Green Button Data Standard, with the NIST Cybersecurity Framework as foundational guidance; and reporting of cybersecurity breach incidents to the Board through the New Jersey Cybersecurity and Communications Integration Cell ("NJCCIC") within six (6) hours; and
4. **Equity and LMI Access:** program design requirements to reduce barriers to participation for LMI customers and customers in overburdened communities, addressed in each EDC's filing.

***3. Accounting for Negative System Peak Load Contributions due to Storage Exports***

Staff understands that changing the way EDCs calculate and report PLCs to PJM would help enable a wider variety of business models that could support storage deployment without the need for state-supplied incentives. Specifically, accounting for the fact that individual customers with BTM storage resources can achieve negative PLCs and NSPLCs by exporting power to the grid during times of peak demand would allow the customer's load serving entity to capture the full value of that load reduction and pass it along to their customers. This in turn could enable innovative business models in which TPSs offer their retail customers rate reductions or other financial benefits in exchange for installing BTM storage resources and operating them in a manner that reduces peak load, outside of an EDC-managed structure like the Block 1 program.

Staff believes that implementing such a change to PLC calculation and reporting methodologies aligns with the policy goal of fostering more market-based VPP frameworks for retail customers. Staff also believes that this methodology revision could be implemented more quickly than the other market support structures described above. Staff therefore recommends that the Board direct the EDCs to develop plans to alter their PLC and NSPLC calculation and reporting methodologies and file summaries of those plans with the Board on or before the date they file the petitions required by this Order. These summaries should describe any technical or legal issues such a methodological change might raise, as well as how those issues could be solved.

# III. DISCUSSION AND FINDINGS

## A. Statutory Authority

### i. VPP Interim

The Board **HEREBY FINDS** that N.J.S.A. 48:3-98.1 authorizes the Board to direct EDCs to implement the VPP Interim Program. Specifically, it authorizes the Board to direct EDCs to undertake energy efficiency and conservation improvements by launching "energy efficiency and conservation programs[36]" which are defined in relevant part as "any regulated program[s] . . . for the purpose of conserving energy or making the use of electricity or natural gas more efficient by

[36] N.J.S.A. 48:3-98.1(a)(3).

New Jersey consumer[37]." The Board has long held that energy efficiency and conservation programs encompass more than just programs that support the deployment of traditional energy efficiency resources.[38] For example, in 2008, just one year after the enactment of N.J.S.A. 48:3-98.1, the Board invoked it as the source of its authority to direct EDCs to stand up demand response programs. More specifically, demand response programs constitute "energy conservation and energy efficiency programs" because they involve customers curtailing their electricity consumption—and thus conserving energy—at times of peak demand or during other grid stress events.

The Legislature itself subsequently endorsed this view when it enacted N.J.S.A. 48:3-87.9 as part of the Clean Energy Act of 2018 ("CEA").[39] There, the Legislature directed EDCs to file petitions pursuant to N.J.S.A. 48:3-98.1 to recover the cost of the "peak demand reduction" programs mandated by the CEA.[40] As N.J.S.A. 48:3-98.1 only applies to "energy efficiency and conservation programs," "class I renewable energy resources," and "class I renewable energy programs," this means that a "peak demand reduction program" falls into one of these categories. Given the Board had previously treated demand response programs as energy efficiency and conservation programs, the Legislature most likely viewed both demand response programs generally and N.J.S.A. 48:3-87.9 peak demand reduction programs specifically as falling into that category.

The VPP Interim Program[41] The VPP Interim Program will build upon these existing programs within the parameters of the MFRs established by this Order. The program seeks to utilize existing assets to respond to calls that qualifies as an energy efficiency and conservation program the Board is authorized to order under N.J.S.A. 48:3-98.1.

## ii. Block 1

The Board **FURTHER FINDS** that N.J.S.A. 48:3-87.8 authorizes the Board to establish the Block 1 storage program. Specifically, it directs the Board to "establish a process and mechanism for achieving the goal of . . . 2,000 megawatts of energy storage by 2030."[42] As the singular includes the plural when it appears in New Jersey statutory language,[43] N.J.S.A. 48:3-87.8 also authorizes the Board to establish multiple processes and/or mechanisms for the purpose of achieving the 2,000 MW energy storage target. A central objective of the Block 1 program is to facilitate the deployment of 150 MW of new BTM energy storage that will contribute to that target. In other

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[37] N.J.S.A. 48:3-98.1(d).

[38] See In re Demand Response Programs for the Period Beginning June 1, 2009 – Electric Distribution Company Programs, BPU Docket No. EO08050326, Order dated Oct. 12, 2008, at 1, 16.

[39] L. 2018, c. 17, § 3.

[40] See N.J.S.A. 48:3-87.9(e)(1) ("Each electric public utility and gas public utility shall file an annual petition with the board to demonstrate compliance with the [requirement to establish] energy efficiency and peak demand reduction programs, . . . and for cost recovery of the programs . . . pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1).").

[41] See, e.g., In re the Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future Energy Efficiency II (CEF-EE II) Program on a Regulated Basis, BPU Docket No. QO23120874, Order dated Oct. 30, 2024, at 5-6, 12, 22.

[42] N.J.S.A. 48:3-87.8(d).

[43] See N.J.S.A. 1:1-2 ("Whenever, in describing or referring to any . . . matter or thing, any word importing the singular number . . . is used, the same shall be understood to include and to apply . . . to several matters and things as well as one matter or thing."); State v. Toth, 354 N.J. Super. 13, 20 (App. Div. 2002) (citing N.J.S.A. 1:1-2) ("[S]ingular words in a statute are to be read as plural.").

words, Block 1 is designed to achieve the 2,000 MW storage goal in combination with other processes and mechanisms the Board is developing or has already established, most notably the GSESP Phase 1 transmission-scale storage solicitations. Consequently, the Block 1 program constitutes "a process and mechanism for achieving the goal of . . . 2,000 megawatts of energy storage by 2030" and therefore the Board has the authority to establish it under N.J.S.A. 48:3-87.8.[44]

The Board **FINDS** that it is appropriate to base the Block 1 MFR process on the process used for Class I renewable energy programs as well as energy efficiency and conservation programs stood up under N.J.S.A. 48:3-98.1. Regardless of whether N.J.S.A. 48:3-98.1 provides an independent source of authority for Block 1 or other potential energy storage programs, the Block 1 program shares several practical similarities with the energy efficiency and conservation programs the Board has approved under N.J.S.A. 48:3-98.1. Specifically, Block 1 is an EDC-administered, customer-facing program designed to incentivize the deployment of resources by customers behind customers' meters and then leverage those resources to reduce peak demand and provide others forms of grid support. The EDC-administered, customer-facing design of Block 1, along with its peak reduction goals, naturally lends itself to the MFR process the Board has developed to implement N.J.S.A. 48:3-98.1. The Board therefore **FINDS** that setting MFRs for the Block 1 program that are modeled after the MFRs used for N.J.S.A. 48:3-98.1 programs is appropriate. The Board **HEREBY ORDERS** the EDCs to file petitions for Block 1 program designs that are consistent with those MFRs.

## B. General findings

Following careful review of the record in this matter, the Board **HEREBY FINDS** that the processes used in developing Staff's recommendations were appropriate and provided stakeholders and interested members of the public with adequate notice and opportunity to comment.

The Board **FURTHER FINDS** that VPPs, inclusive of distributed energy storage, are among the fastest means available to address the supply-demand imbalance driving New Jersey's electricity affordability crisis. Unlike centralized generation, which faces multi-year equipment backlogs and long development timelines, these resources are already installed or can be deployed within months, and can be dispatched to reduce peak demand, relieve local distribution constraints, reduce transmission charges, and reduce the capacity New Jersey's zones must procure in the PJM capacity market. Energy storage is a necessary component of a functioning VPP, and for that reason the Board establishes the Block 1 storage program together with the VPP Interim Program under the unified PowerUp NJ Program.

The Board **FURTHER FINDS** that development of these programs, consistent with the framework described herein, effectuates the directives of EO 2, advances the objectives of EO 1, and is consistent with the Board's responsibility under Title 48 to ensure safe, adequate, and proper utility service at just and reasonable rates.[45]

The Board **FURTHER FINDS** that providing a consistent program name, PowerUp NJ and brand will accelerate the adoption of the program and spur on savings for ratepayers.

[44] N.J.S.A. 48:3-87.8(d).

[45] N.J.S.A. 48:2-21; N.J.S.A. 48:2-23.

## C. Cost recovery and performance incentive mechanisms

The Board **FINDS** that conventional cost-of-service treatment alone is not well suited to these programs. Under conventional treatment, a utility recovers prudently incurred expenses and earns a return on approved capital investment. That structure does not by itself tie utility earnings to delivered load reduction or verified cost savings.

The Board **FURTHER FINDS** that ratepayers are entitled to a mechanism under which utility earnings track verified system benefit. Accordingly, the Board **ADOPTS** Operating Expense treatment for program costs recovered as current expenses, without a separate equity return on those reimbursements. Any proposed capital or other deferred investment and associated return shall be separately justified and considered in the EDC's proceeding under applicable law.

In addition, the Board **DIRECTS** Staff to evaluate a mechanism under which EDC earnings are tied to and may scale with verified ratepayer savings or other quantitative performance benchmarks that are reasonably related to ratepayer benefits. This Order does not establish that additional mechanism or waive applicable cost-recovery, incentive, or penalty requirements. N.J.S.A. 48:3-98.1 permits the Board to approve rate treatment including a return on equity or other incentives or rate mechanisms that decouple utility revenue from sales of electricity and gas. The Board may exercise that discretion in future proceedings.

The Board **FURTHER FINDS** that recovery of prudently incurred Operating Expenses should not be conditioned on achievement of the performance target. An EDC that spends prudently in pursuit of an approved program should recover what it has spent.

## D. Benefit cost analysis

The Board **FINDS** that requiring all six (6) BCA tests provides an appropriate basis for evaluating these programs and for comparing them to other Board-approved programs. The Board **FURTHER FINDS** that the RIM test should serve as the primary BCA test and that each EDC VPP Interim and Block 1 program proposal must have a benefit-to-cost ratio greater than 1.0 under the RIM test in order to secure Board approval or justify why it has deviated from that requirement. The Board **FURTHER FINDS** that specifying the benefit and cost line items to be included in those tests is necessary so that the four EDC filings contain consistent BCA calculations that can be meaningfully compared, and adopts the line items set forth in Tables A-1 and A-2 of Attachment A and Tables B-1 and B-2 of Attachment B.

The Board **HEREBY ORDERS** that where it has not adopted a schedule of unit values for specific line items, each EDC shall propose the methodology and unit value for those specific line items together with their derivation and input sources in the petitions directed by this Order. This will enable the Board to review and either approve, reject, or modify the relevant unit values in the Order addressing each EDC's petition.

## E. Program structure and filing requirements

The Board **FINDS** that the two-phase VPP implementation framework – an EDC-administered interim program that leverages existing AMI infrastructure, direct load control platforms, and the Triennium 2 DR customer base, followed by a long-term, open-access, market-based framework – reasonably balances the urgency of near-term peak demand reduction against stakeholder input and the EDC investment and systems integration required for a durable competitive market. The Board **FURTHER FINDS** that the Block 1 program as proposed in this Order will be a valuable complement to this VPP implementation framework. The Board **FURTHER FINDS** that requiring

filings pursuant to uniform MFRs provides sufficient direction to the EDCs for program design, while allowing appropriate flexibility in implementation, and that the reporting requirements adopted herein are necessary for Board oversight of program performance and cost-effectiveness.

Therefore, the Board **HEREBY ADOPTS** Staff's recommendations for both the VPP Interim Program and Block 1, as outlined above, with the specific directives set forth below.

The Board **HEREBY ORDERS** that the suite of programs established by this Order shall be known and marketed as PowerUp NJ, comprising the VPP Interim Program and the Block 1 Program, and **HEREBY ADOPTS** the MFRs set forth in Attachment A and Attachment B to this Order.

The Board **HEREBY ADOPTS** the definitions set forth in Section II.A.ii of this Order, which shall have the same meaning throughout this Order and its Attachments. The Board **FURTHER ORDERS** that participation in PowerUp NJ shall follow the VPP Provider rules set forth in Section II.A.iii, including that: (1) each enrolled device shall have exactly one VPP Provider; (2) a Site may have one Site Aggregator or one or more DER Providers, but not both; (3) an energy storage system may be enrolled in Block 1 only through a DER Provider, and a Site with an energy storage system enrolled in Block 1 may not have a Site Aggregator; and (4) an energy storage system at a Site enrolled by a Site Aggregator may participate in the VPP Interim Program as part of that Site but shall not be enrolled in, or receive compensation from, Block 1.

The Board **HEREBY ORDERS** each EDC to file with the Board, no later than February 12**,** 2027, a petition proposing its PowerUp NJ program consistent with those MFRs set forth in Attachment A and Attachment B and with the recommendations outlined in this Order. The Board **FURTHER ORDERS** that any EDC VPP Interim subprograms that were not part of the Triennium 2 DR portfolio shall be operational no later than October 1, 2027, and that VPP Interim sub-programs migrating from the Triennium 2 DR portfolio shall be operational no later than October 1, 2027, in each case subject to Board approval of the EDC's Filing, and that the programs shall run through September 30, 2029.

The Board **HEREBY ORDERS** that the VPP Interim Program be designed as a clean energy, technology-neutral program open to all DER types capable of delivering dispatchable demand reduction on a reliable, event-driven basis, with a minimum aggregation size of ten (10) kW per EDC Dispatch Event. Until the Board orders otherwise, a Host Customer with a solar-only system on a NEM tariff may not enroll that solar system in the VPP Interim Program.

The Board **HEREBY ORDERS** that each EDC's Block 1 Program shall be operational within sixty (60) days of the date the Board approves that EDC's Block 1 Program. The Program shall provide a maximum performance-based incentive of $200/kW per year for ten (10) years for up to 150 MW of New Storage and a maximum performance-based incentive of $100/kW per year for ten (10) years for up to 100 MW of Existing Storage, with the exact incentives for participating resources calculated pursuant to the methodology described in Attachment E to this Order. The Board **HEREBY FINDS** that all customers eligible to take BGS-RSCP supply who install BTM energy storage systems shall be eligible to participate as Host Customers in the Block 1 program, regardless of whether they receive BGS supply or obtain generation services from a TPS, subject to the rules on anti-double counting specified within this Order.

The Board **HEREBY ORDERS** that each EDC pay Block 1 incentives to DER Providers by direct monetary payment, and that the DER Providers pass Host Customers' share of Block 1 incentive payments on to their Host Customers pursuant to their relevant agreements.

The Board **HEREBY ORDERS** that 150 MW of Block 1 capacity of New Storage be allocated

among the EDCs based on each EDC's share of total New Jersey residential sales. The initial allocation is seventy-three (73) MW for PSE&G, fifty-two (52) MW for JCP&L, twenty-one (21) MW for ACE, and four (4) MW for RECO.

The Board **HEREBY ORDERS** that 100 MW of Block 1 capacity of Existing Storage be allocated among the EDCs based on each EDC's share of total New Jersey residential sales. The proposed allocation is forty-nine (49) MW for PSE&G, thirty-four (34) MW for JCP&L, fourteen (14) MW for ACE, and three (3) MW for RECO. As part of each EDC's filing, EDCs shall provide an estimate on a nameplate capacity basis for how much eligible Existing Storage it anticipates may enroll within its territory. The Board **HEREBY DIRECTS** Staff to recommend adjustments to these allocations on the basis of these EDC estimates, which the Board may then incorporate into the Orders approving the EDCs' Block 1 program designs.

If during the enrollment period, one EDC's Block 1 capacity is filled and/or becomes oversubscribed while another EDC's capacity remains undersubscribed, the Board **HEREBY DIRECTS** Staff to reallocate any unused capacity as needed to support the ongoing enrollment of BTM storage resources in Block 1.

The Board **HEREBY ORDERS** the EDCs to process interconnection requests for both export-capable standalone storage and solar-plus-storage systems with an export-capable storage component in accordance with the Board's regulations set forth at N.J.A.C. 14:8-5.1 through N.J.A.C. 14:8-5.13. The Board **FURTHER ORDERS** the EDCs to allow exports from both standalone storage systems and the storage components of solar-plus-storage systems in accordance with Staff's recommendations. The Board **FURTHER ORDERS** EDCs to allow customers with existing standalone storage and the storage components of existing solar-plus-storage systems to obtain permission to export by submitting new interconnection requests. In accordance with the Board's interconnection rules set forth at N.J.A.C. 14:8-5.1 through N.J.A.C. 14:8-5.13, the Board **FURTHER ORDERS** EDCs to consider any existing and proposed export capacity limitations in determining whether new studies are needed when processing interconnection requests from existing solar plus storage systems seeking permission to export from their storage components.

The Board **HEREBY FINDS** that kWh discharged from an energy storage system that is paired with onsite solar array and exported to the grid are eligible for NEM credits if (1) the discharged energy was stored solar energy sourced entirely from the onsite solar array and (2) the onsite solar array is eligible for NEM. The Board **HEREBY ORDERS** the EDCs to credit all kWh exports from a customer with a NEM-eligible solar-plus-storage system at the applicable NEM rate provided the storage component is configured to operate in a NEM integrity mode that ensures any kWh the storage component exports to the grid are sourced exclusively from the onsite solar array. The Board **HEREBY CLARIFIES** that customers with existing solar-plus-storage systems that are currently net metered and lack permission to export from the storage component of their system remain eligible to receive NEM credit for their solar exports regardless of whether the storage component of their system is configured to operate in a NEM integrity mode. However, if such customers obtain permission to export from the storage component of their solar-plus-storage systems, they must then operate the storage component of their systems in a NEM integrity mode in order to continue receiving NEM credits for their exports. The Board **FURTHER ORDERS** the EDCs to file any tariff revisions needed to implement these NEM directives and clarifications for solar-plus-storage systems within sixty (60) days of the effective date of this Order.

The Board **HEREBY ORDERS** that, until the Board approves a tariff or issues a new Order directing otherwise, BTM standalone storage systems shall not receive any state-level

compensation for kWh exports other than the compensation provided by the Block 1 program. The Board notes that this is an interim measure until the Board can determine the appropriate compensation rate for kWh exports from standalone storage systems on the basis of a more developed record. To the extent the EDCs need to specify a tariff compensation rate in the interim period for kWh exports from standalone storage systems to enable them to export, the Board **FURTHER ORDERS** the EDCs to file tariff revisions that specify a zero-compensation rate for kWh exported from a standalone storage system within sixty (60) days of the effective date of this Order.

The Board **HEREBY ORDERS** that all costs of the PowerUp NJ Program shall be recovered as an Operating Expense as defined in this Order, with the exception of any capital investment an EDC demonstrates is needed to support the program and which the Board specifically approves. Customer incentive amounts are a sub-category of Operating Expense. Recovery of Operating Expense is subject to a prudence standard and annual reconciliation. The Board does not anticipate the need for capital investment to stand up the PowerUp NJ Program established in this Order; however, the EDCs may provide a detailed description of any necessary capital costs and their proposed recovery treatment, subject to applicable law and Board approval. The Board **HEREBY RESERVES** the authority to recalibrate the recovery mechanism at the Midterm Review based on observed performance and avoided-cost data.

The Board **FURTHER ORDERS** that EDCs shall calculate and report avoided costs using the methodologies and unit values each EDC proposes under Section V of Attachments A & B and the Board approves in the order approving that EDC's petition.

The Board **HEREBY ORDERS** that each EDC either propose a peak demand reduction target of no less than three-and-one-half percent (3.5%) of service-territory peak load for the PowerUp NJ Program in the aggregate, of which no less than three percent (3%) shall be contributed by the VPP Interim Program, or justify any deviation below those levels, and propose cost savings targets for each category of savings described in this Order.

The Board **HEREBY ORDERS** that load reduction compensated under Block 1 or under a Triennium program shall not simultaneously be counted toward the VPP Interim Program peak demand reduction target and vice versa. The Board **HEREBY ORDERS** that the VPP Interim Program budgets set forth in Table 3 serve as guidance, and that an EDC proposing a budget deviating by more than fifteen percent (15%) from the applicable figure must provide a detailed written justification in its filing for the deviation.

The Board **HEREBY ORDERS** that no single device shall be enrolled in both the VPP Interim Program and Block 1 at the same time. At a Site with an energy storage system enrolled in Block 1, the EDC shall measure VPP Interim Program performance at the retail meter after removing the energy storage system's charge and discharge, as measured by the energy storage system's meter, from both the baseline and the event load. A Host Customer may leave either program at any time without an early-exit penalty.

The Board **FURTHER ORDERS** that the budget for Block 1 set forth in Table 4 serve as guidance for the incentive budget for Block 1 storage resources, and that the EDCs propose a budget for the Block 1 resources that they anticipate can be enrolled by September 30, 2029, in addition to an EDC administration budget that is no more than three percent (3%) of the total incentive budget, unless the EDC can specifically demonstrate in their filing why the budget needs to be higher.

The Board **HEREBY ORDERS**, as it pertains to the VPP Interim Program, that each EDC measure performance at the Site's retail meter and compensate participants as follows: (1) for a

Site enrolled through one or more DER Providers, the EDC shall pay the Host Customer, directly or through the EDC's contractor, based on the Site's net load reduction, and shall separately pay each DER Provider under its contract with the EDC; and (2) for a Site enrolled by a Site Aggregator, the EDC shall pay the Site Aggregator per kW delivered. The Board **FURTHER ORDERS** that any VPP Interim compensation paid to a Host Customer be made by direct monetary payment, such as check, electronic funds transfer, or gift card, and not as a credit on the Host Customer's electric bill, and that each EDC require the same of Site Aggregators in its EDC–Site Aggregator contracts. The Board **FURTHER ORDERS** that in designing the VPP Interim Program compensation the value of the incentive should remain consistent with the companion storage incentive ($100-$200/kW).

The Board **HEREBY ORDERS**, as it pertains to the VPP Interim Program, that any competitive procurement by an EDC be limited to its own systems and implementation services, which may include VPP Provider(s) or edge DERMS Provider(s), and that such procurement shall not limit participation by any other VPP Provider that meets the program requirements; that EDC-Site Aggregator-contracts be performance-based; that EDC-DER Provider contracts compensate DER Providers for reliably providing device data and carrying out dispatch signals; that all EDC-VPP Provider contracts include the compensation, cost-effectiveness, and contracted MW commitment provisions described herein; that each EDC disclose its VPP Provider contract values, pass-through requirements, and double-payment safeguards in each Annual Report described in this Order; and that all such contracts include a transition clause and a parallel-operation period of no less than twelve (12) months.

The Board **HEREBY ADOPTS**, for the VPP Interim Program, a non-binding goal that Site Aggregators pass through to Host Customers no less than seventy percent (70%) of the compensation they receive under EDC–Site Aggregator contracts, and **DIRECTS** each EDC to report actual pass-through in its Annual Report.

The Board **FURTHER ORDERS** that the EDCs shall develop an enrollment protocol for VPP Providers, including a standard application and participation agreement, that provides a simple mechanism for VPP Providers that meet the VPP Provider requirements, including eligibility, technical, and performance requirements, and that each EDC include this protocol in its petition.

The Board **HEREBY DIRECTS** the EDCs to continue their Triennium 2 DR programs without interruption, consistent with the Program Year 7 Order, until the VPP Interim Program is operational, at which time those programs and their associated cost recovery shall migrate into the VPP Interim Program as approved by the Board.

The Board **HEREBY ORDERS** that where an EDC's approved VPP Interim Program filing does not contain the full operational details of a proposed VPP Interim subprogram, the EDC shall provide Staff with those details before launching the subprogram, and shall not launch such a subprogram until Staff has reviewed those details to ensure they are consistent with the program design approved by the Board and the sub-program advances the purposes of this Order. The Board **HEREBY AUTHORIZES** Staff to direct the EDCs to proceed with any such VPP Interim sub-program if, following this review, Staff determines that the sub-program is consistent with the program design approved by the Board and advances the purposes of this Order. The Board **FURTHER DIRECTS** each EDC to identify in its filing any element it expects to develop after approval.

The Board **HEREBY ORDERS** that VPP Interim EDC Dispatch Events follow the parameters in Section II.B.iv, including a maximum duration of three (3) hours per event and no more than thirty-five (35) EDC Dispatch Events per calendar year, unless an EDC justifies a different parameter in its filing and the Board approves it.

The Board **HEREBY DIRECTS** each EDC to describe in its filing how it will report a PSA plan, that includes the VPP enrolled devices, to PJM for the load reduction its VPP Interim Program is forecasted to deliver, and to identify any impediment to doing so. The Board **HEREBY ORDERS** that each EDC may set PSA-specific dispatch parameters within the event limits set in this Order, or as justified in its filing, and shall submit a PSA for the portion of its VPP Interim Program and any other demand response program (excluding its Block 1 Program) it manages that can meet PJM's PSA requirements. The Board **FURTHER ORDERS** that each EDC shall file its PSA plan, or its successor, with PJM by the earlier of September 10 of each year or the PJM-established deadline for PSA plan submission for the relevant year, starting in 2027. The Board **FURTHER ORDERS** that the filing shall include a description of which resources shall be included in the 2027 PSA plan, as well as include a list of any demand response resources the EDC manages which cannot be included in the PSA plan and an explanation of why those resources cannot meet PJM's PSA requirements. The Board **HEREBY DIRECTS** the EDCs to provide any assistance or data Staff needs to ensure PJM fully incorporates the impacts of the Block 1 Program into its load forecast. The Board **HEREBY ORDERS** that it shall retain the authority to direct the EDCs to transition their Block 1 Programs into PSA plans or similar structures if and when amendments are made to PJM's governing documents that render such pathways viable for BTM storage and the Board determines such a transition is in the best interest of New Jersey ratepayers.

The Board **HEREBY ORDERS**, for the VPP Interim Program, that each EDC file the quarterly Reports, Event-Level Reports, and Annual Reports described in this Order, with the Year 1 Annual Report serving as the Midterm Report. Each EDC shall file these reports on the schedule set out in this Order. The reports shall measure the EDC's performance against the QPIs approved for the utility. All public reports relevant to the VPP Interim Program should be filed as specified in the body of this Order, and Event-Level Reports shall be submitted to Staff on a confidential basis.

The Board **HEREBY ORDERS**, for Block 1, that each EDC to provide an Annual Report within ninety (90) days of the end of the relevant performance year, as described above in this Order, measured against the QPIs approved for the utility. The Board **HEREBY ORDERS** that EDCs shall submit a Preliminary Report, no later than thirty (30) days from after the end of a Performance Year as described above in this Order. All reports relevant to Block 1 should be filed as specified in the body of this Order. The Board **FURTHER ORDERS** that after two annual performance-year reports have been submitted by the EDCs, Staff shall release an Interim Report to evaluate Block 1 and make recommendations regarding the modification and/or expansion of Block 1.

The Board **HEREBY DIRECTS** Staff to begin the process of retaining an independent evaluator to calculate program savings, and **FURTHER DIRECTS** Staff to conduct or cause to be conducted the Midterm Review of the VPP Interim Program, covering the first twelve (12) months of operation and based on each EDC's Midterm Report. The Board will then consider the findings of the Midterm Review to determine whether the programs should be modified, expanded, or phased out in favor of the long-term framework.

The Board **HEREBY DIRECTS** Staff to review the petitions the EDCs file in response to this Order and to present recommendations for Board action in a timeframe that supports program launch by the dates ordered herein.

The Board **HEREBY DIRECTS** Staff to begin a public education campaign on PowerUp NJ, including development of marketing and branding materials and a logo and branding standard to be shared with the EDCs, prior to program opening, so that ratepayers understand how the programs can lower energy costs for participants and for other ratepayers.

The Board **HEREBY DIRECTS** Staff, working with the GridFlex workgroup, to develop and issue for stakeholder comment, a straw proposal on the long-term open-access VPP tariff, and **FURTHER DIRECTS** Staff to develop, for future Board consideration, the DER Aggregator licensing framework and Code of Conduct, the DER Registry structure, and the cybersecurity and data-access standards described herein, so that these market support structures are in place when the long-term framework launches.

The Board **HEREBY DIRECTS** the EDCs to develop plans to revise their PLC calculation and reporting methodologies to account for negative PLC and NSPLC, and file summaries of those plans with the Board by no later than February 12, 2027.

The Board **HEREBY DIRECTS** Staff to prepare recommended clarifications that the Board can incorporate into a future Order regarding how the Board's interconnection rules set forth at N.J.A.C. 14:8-5.1 through N.J.A.C. 14:8-5.13 apply to FTM energy storage facilities. The Board **FURTHER DIRECTS** Staff to work expeditiously on this issue so that EDCs can begin processing FTM energy storage facility interconnection applications with the benefit of this guidance in parallel to the development of the tariffs that will govern charging rates and discharge compensation for FTM energy storage facilities.

The Board **HEREBY DIRECTS** Staff and the EDCs to coordinate the PowerUp NJ Program with the Board's parallel proceedings – including the Triennium proceedings, the PSUP proceeding, the AMI data access rules, NEM reform, Grid Flexibility proceeding, and managed EV charging programs – to prevent duplicative compensation for the same service, ensure consistent technical requirements, and better understand how New Jersey DERAs can access wholesale market revenue streams and meet PJM participation deadlines for auctions following the necessary PJM Tariff revisions expected to be completed by February 1, 2028.

The Board **HEREBY ORDERS** Staff to work with stakeholders to convene the PowerUp NJ Working Group and all relevant subgroups upon the approval of the EDC filings. The Board **HEREBY ORDERS** Staff to convene the EM&V subgroup to develop the shared EM&V metrics and methodology. Those metrics and methodology shall be proposed to Staff for approval within sixty (60) days of Board approval of the EDC petitions. Staff shall approve, deny, or deny in part the proposal within twenty-one (21) days.

The Board **HEREBY NOTES** that it will consider, in due course, any and all proposals contained within the EDCs' petitions. Unless stated otherwise herein, the Board **HEREBY APPROVES** all recommendations made by Staff above. This Order shall not be construed to pre-approve any cost recovery, which shall be addressed upon Board review of the EDCs' individual filings.

The Board **HEREBY ORDERS** that all EDC petitions shall be filed as new matters and in the PowerUp NJ Docket, No. QO26100658.

The Board **FURTHER ORDERS** that all provisions of this Order shall apply for the full term of the PowerUp NJ Program except as modified by subsequent Order.

The EDCs' costs, including those related to the PowerUp NJ Program, will remain subject to audit by the Board. This Decision and Order shall not preclude or prohibit the Board from taking any actions determined to be appropriate as the result of any such audit.

This Order shall be effective on November 12, 2026.

DATED: November 12, 2026

BOARD OF PUBLIC UTILITIES
BY:

BEN HERTZ-SHARGEL
PRESIDENT

CHRISTINE GUHL-SADOVY
COMMISSIONER

MICHAEL BANGE
COMMISSIONER

EMMA REBHORN
COMMISSIONER

JOSEPH COVIELLO
COMMISSIONER

ATTEST:

SHERRI L. LEWIS
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 ESTABLISHING THE POWERUP NEW JERSEY PROGRAM**
**DOCKET NO. QO26100658**

**IN THE MATTER OF ADVANCING VIRTUAL POWER PLANT (VPP) PROGRAM IN THE STATE OF NEW JERSEY**
**DOCKET NO. QO26030099**

**IN THE MATTER OF THE GARDEN STATE ENERGY STORAGE PROGRAM – PHASE 2 DISTRIBUTED STORAGE**
**DOCKET NO. QO26040116**

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**ATTACHMENTS**

A. Minimum Filing Requirements for Virtual Power Plant Interim Program

B. Minimum Filing Requirements for Block 1

C. Responses to the VPP Straw Comments

D. Responses to the Block 1 Program Straw Comments

E. Block 1 Incentive Payment Calculation Example

F. Interim VPP – Benefit-Cost Analysis Methodologies and Assumptions

G. Block 1 – Annual Block 1 Benefit-Cost Analysis Methodologies and Assumptions

H. Block 1 – Benefit-Cost Analysis

# Attachment A

In the Matter of Establishing the PowerUp New Jersey Program, Docket No. QO26100658

In the Matter of Advancing a Virtual Power Plant (VPP) Program in the State of New Jersey Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program – Phase 2 Distributed Storage, Docket No. QO26040116

MINIMUM FILING REQUIREMENTS FOR THE VIRTUAL POWER PLANT INTERIM PROGRAM PETITION UNDER N.J.S.A. 48:3-98.1

The Virtual Power Plant ("VPP") Interim Program is a component program of the PowerUp NJ Program established by the Order to which this Attachment is appended (the "Order"). Terms defined in Section II.A.ii of the Order have the same meaning in this Attachment. Each electric distribution company ("EDC" or "utility") shall file a petition proposing its PowerUp NJ Program no later than February 12, 2027. This Attachment sets the minimum filing requirements ("MFRs") each petition shall include with respect to the VPP Interim Program. The MFRs for Block 1 are set forth in Attachment B.

Program parameters referenced in these requirements – including the event dispatch parameters, peak demand reduction goals, program budgets, cost recovery treatment, and VPP Provider contract requirements – are established in the Order and are not restated here. The utility applies the cost test methodologies and assumptions provided by Staff in the Order and Attachment F to the Order, and proposes any other values, for Board approval, under Section V. For purposes of this Attachment, "performance year" means October 1 through September 30, except that the first performance year begins on the date the first VPP Interim sub-program becomes operational, and the last performance year ends September 30, 2029.

## I. General Filing Requirements

a. The utility shall provide a table of contents and page number for each filing.

b. The utility shall provide with all filings, information and data pertaining to the specific program proposed, as set forth in applicable sections of N.J.A.C. 14:1-5.11 and N.J.A.C. 14:1-5.12.

c. All filings shall contain information and financial statements for the proposed program(s) in accordance with the applicable Uniform System of Accounts that is set forth in N.J.A.C. 14:1-5.12. The utility shall provide the accounts and account numbers that will be utilized in booking the revenues, costs, expenses, and assets pertaining to each proposed program so that they can be properly separated and allocated from other regulated and/or other programs.

d. The utility shall provide supporting explanations, assumptions, calculations, and work papers as necessary for each proposed program and cost recovery mechanism petition filed under N.J.S.A. 48:3-98.1. The utility shall provide

electronic copies of such supporting information, with all inputs and formula intact, where applicable.

e. The filing shall include testimony supporting the petition, including all proposed programs and subprograms.

f. For any proposed program, the utility shall be subject to the requirements in this and all subsequent Sections. If compliance with Section V or Section VI of this Attachment would not be feasible for a particular program or sub-program, the utility may request an exemption but must demonstrate why such exemption should be granted. Examples of historical situations that have qualified for exemption include pilot programs, programs that had an educational or policy goal rather than resource acquisition focus, and programs that introduced novel ideas where documentation supporting estimated costs/benefits may not be easily produced. No exemption is available from the cost recovery showings required by Section IV.

g. If the utility is filing for an increase in rates, charges, etc. or for approval of a program that may increase rates/charges to ratepayers in the future, the utility shall include a draft public notice with the petition and proposed publication dates.

## II. Program Description

a. The utility shall provide a detailed description of each proposed program for which it seeks approval, including, if applicable:

   i. Program description/design, including a narrative explaining how the proposed program meets the objectives of the VPP Interim Program established in the Order, how the proposed cost savings goals will be achieved, and how the program is positioned to transition to the long-term VPP Program framework.

   ii. Target market segment – including eligible customer class(es), eligible distributed energy resource (“DER”) types, eligible DER numbers, the average DER nameplate capacity (in kW), and how the utility will apply the minimum aggregation size of ten (10) kW per EDC Dispatch Event established in the Order – and eligibility requirements and enrollment processes. A battery may be enrolled individually only in Block 1, through a DER Provider, and is addressed in Attachment B (“Block 1 MFR”). A battery may be included in the VPP Interim Program only as part of a Site enrolled by a Site Aggregator, as provided in Section II.A.iii of the Order. Until the Board orders otherwise, a solar-only system on a NEM tariff may not be enrolled in the VPP Interim Program, as the Order provides. Consistent with the Order, the VPP Interim Program is designed as a clean energy, technology-neutral program, and the eligible DER devices the utility proposes shall be consistent with that design. The utility shall also provide its terms of enrollment, including the terms a Host Customer and a VPP Provider must accept to enroll; how the utility will accept enrollments on a

first-come, first-served basis; and the point at which it will pause new enrollments as it reaches its program budget, including how it will notify Host Customers and VPP Providers of a pause.

iii. Existing incentives, including any incentive an enrolled Host Customer may receive under an existing Triennium 2 demand response ("DR") program, Block 1, an electric vehicle ("EV") charging program, or any other Board-approved program, and the safeguards preventing double-payment for the same resource or the same performance. For any Triennium interest-free residential storage loan that requires the storage system to respond to utility dispatch events, the utility shall identify the loan program, the number of systems and kW enrolled, and when each dispatch obligation ends, as the Order requires.

iv. Proposed incentive structure or incentive ranges for each VPP Provider path described in Section II.A.i.i of the Order, including the determination method, form of payment (which shall be direct monetary payment and not a bill credit, as the Order requires), incentive payment processes, and timeframes for each path, and:

    1. For Sites enrolled through DER Providers, the performance payment to the Host Customer for the Site's net load reduction ; and

    2. For Sites enrolled by a Site Aggregator, the per-kW payment to the Site Aggregator.

v. Contractor requirements and role:

    1. The utility shall provide a description of the extent to which it intends to utilize employees, contractors, or both to deliver the program(s), including the role of any Implementation Contractor ("IC").

    2. The utility shall also provide a description of contractor requirements to ensure competitive bidding, including common application elements and training requirements

vi. Estimated number of Host Customers, Sites, VPP Providers, and enrolled devices, by year.

vii. Projections for peak demand savings, number of enrolled devices (by device type), and financial savings generated, and associated metrics for each performance year relative to the quantitative performance indicators in Section VII

viii. Program budget, by year, stated separately from the GSESP Block 1 budget, together with:

    1. A detailed written justification for the proposed VPP Interim Program budget, explaining how the budget was developed and

how it supports the proposed program design, participation, and peak demand reduction projections. The justification shall tie to the projected program costs in item ix;

2. A comparison of the proposed budget to the budget guidance established for the utility in the Order, showing the dollar and percentage difference; and

3. If the proposed budget deviates by more than fifteen percent (15%) from the budget guidance, a separate, detailed written justification for the deviation.

ix. Projected program costs, by year, broken down into the following categories and each with a detailed description, further breakdown, and justification of the amount, as applicable:

1. Capital cost

2. Utility administration and program implementation

3. Marketing and outreach

4. Outside services with a detailed description of those costs

5. Customer incentives paid by the utility, or its contractor, directly to Host Customers

6. Payments to VPP Providers, stating separately performance-based payments to Site Aggregator and contract payment to Site Aggregators and contract payments to DER Providers

7. Inspection and quality control

8. Evaluation, measurement, and verification (“EM&V”)

The Order provides that program costs are treated as Operating Expense unless the Board expressly approves a demonstrated capital investment that is necessary to implement the program. If the utility proposes any cost for capital treatment, it shall identify that cost separately and provide a detailed justification. To the extent that the New Jersey Board of Public Utilities (“Board” or “BPU”) directs New Jersey’s Clean Energy Program (“NJCEP”) to report additional categories, the utility shall provide additional categories, as applicable.

x. Event dispatch protocol and notification timeline, together with a demonstration that the proposed protocol conforms to the event dispatch parameters established in the Order or a justification for any proposed deviation. The utility shall also describe the capability of its dispatch platform to segment enrolled resources by substation, feeder, technology

type, and response capability. The utility shall also define the conditions that qualify as a grid stress event and explain how it will decide day-ahead or in real time to call one, as the Order requires, and any PSA-specific dispatch parameters described under the PSA item below. The EDC shall develop dispatch protocols that maximize the opportunity for ratepayer savings.

xi. Enabling infrastructure and technical integration requirements: the DERMS or other dispatch platform the utility will use; the integration methods it will support for devices and VPP Providers, including open-standard protocols, VPP Provider application programming interfaces ("APIs"), or both; the technical requirements a device or VPP Provider must meet to integrate with that platform; documentation of existing dispatch communication capabilities, including those of DR program partners and any Implementation Contractor; the estimated number of enrolled devices and eligible customer accounts; and any gaps or constraints limiting near-term program scale. The utility's integration requirements shall be consistent with the technology-neutral design established in the Order and shall not limit the type or number of eligible devices or VPP Providers.

xii. Engagement model with VPP Providers: the respective roles of the utility, any Implementation Contractor, any DERMS Provider, Site Aggregators, DER Providers, and any third-party supplier; and a description of how the utility will offer the Site Aggregator and DER Provider pathways to Host Customers as required by the Order

xiii. VPP Provider solicitation plan: the solicitation form, evaluation criteria, and associated fees; the anticipated number of VPP Providers by resource type and/or customer segment; the utility-established interim qualification criteria for Site Aggregator and DER Provider participation; a description of how the utility will classify each VPP Provider, including original equipment manufacturers ("OEMs"), third-party suppliers, and other organizations, as a Site Aggregator or a DER Provider, consistent with Section II.A of the Order; a description of how current Triennium 2 DR vendor and OEM relationships will transition into the program; and a timeline ensuring selected VPP Providers can begin enrollment

xiv. VPP Provider contract requirements and disclosures: a demonstration that the utility's VPP Provider contracts will satisfy the contracting requirements established in the Order for Site Aggregators and DER Providers, and confirmation that the utility will disclose to the Board, in each Annual Report required by the Order, the total contracted value with Site Aggregators and DER Providers, stated separately and broken down by payment type; the Host Customer pass-through reporting requirements and methodologies imposed by contract on Site Aggregators, together with the utility's actual pass-through by Site Aggregators measured against the seventy (70) percent non-binding goal established in the Order; and the contractual safeguards preventing double-payment with co-enrolled Triennium 2 DR programs

xv. Peak demand reduction target: a proposed target, expressed in MW, for the first full operating year and each subsequent performance year, stating separately the contribution of the VPP Interim Program and the projected contribution of Block 1 (as filed under Attachment B) toward the aggregate PowerUp NJ Program goal established in the Order, or accompanied by a justification for a lower target, and in either case accompanied by the assumptions underlying the proposed target and the peak-load basis used. The VPP Interim Program contribution shall be measured as the verified load reduction during PJM's 5CP hours, calculated under Section VII(b)(iv). The utility shall also state the load reduction it expects to deliver during the transmission 1CP hour. Load reduction from winter-season, grid stress, and distribution-level events does not count toward this target; it is reported under Section VII(b)(ix) and reflected in the cost savings targets under Section II(a)(xvi).

xvi. Cost savings target for each savings category identified in the Order, and for any additional category the utility proposes, including a detailed narrative of how the utility proposes to achieve said savings.

xvii. Forecast table: a table, by program and by year, presenting forecasted values for the number of Host Customers and Sites; total load under management (kW or MW); load reduction during PJM's five (5) coincident peaks ("5CP") hours (kW or MW), stated as a single value calculated the same way as Section VII(b)(iv); program budget; cost to achieve ($/kW); percent peak shaving (load dropped divided by total peak); and forecasted verified savings by avoided-cost line item as specified in Section V(c).

xviii. Planning and operations integration: a description of how the utility will incorporate VPP-provided grid services into its distribution planning and operations during the VPP Interim Program period, including its plan to test localized DER dispatch, how its planning and operations teams will be involved in that testing, and coordination with its proactive distribution planning.

xix. Transition strategy:

1. confirmation that VPP Provider contracts will include a transition clause and the proposed parallel-operation period of no less than twelve (12) months required by the Order, and a description of how the utility will carry enrolled Host Customers' enrollment and device data forward, with Host Customer consent, so that customers do not need to re-enroll once the Board adopts a long-term open-access tariff, subject to the terms of that tariff. The utility shall update this description after the Board adopts the long-term tariff; and

2. a description of how dispatch authority, AMI data provisioning, PJM communication, and marketing and enrollment will transition from the utility or its Implementation Contractor to VPP Providers over time

xx. Implementation schedule with key milestones from Board approval through program launch, demonstrating that all VPP Interim sub-programs, including those migrating from the utility's Triennium 2 DR portfolio will be operational by October 1, 2027.

xxi. A description of how the program will comply with the applicable standards and guidelines established by the Board, including those governing information sharing and transparency, the DER registry, DER Aggregator conduct, cybersecurity, and marketing and public outreach

xxii. Identification of any element of the proposed program the utility expects to develop after Board approval, together with the utility's acknowledgement that it will return to the Board with that detail before launching the affected sub-program

xxiii. Peak shaving adjustment ("PSA") plan. The utility shall submit a PSA plan to PJM in each year of the program term for the load reduction the VPP Interim Program is expected to deliver. In its filing, the utility shall describe:

1. Deadline: how the utility intends to meet the Board-imposed September 10 deadline, as well as PJM's PSA deadline: the utility shall submit its PSA plan to PJM by September 10 of each year, beginning in 2027. If PJM sets an earlier deadline for that year, the utility shall meet PJM's deadline instead. If PJM changes its deadline, the utility shall notify the Board in writing within ten (10) business days of the change.

2. First PSA: how its PSA plan will include the load reduction from its Triennium 2 DR and VPP pilot programs that migrate into the VPP Interim Program, informed by the most recent measured event performance of those programs, together with projected VPP Interim Program forecast.

3. Later PSAs: how each later PSA plan will reflect the verified load reduction from the prior performance year plus load reduction expected from the new enrollment.

4. PSA dispatch parameters: the temperature-humidity index (THI) trigger, event hours, and notification process the utility will use to meet PJM's peak shaving requirements,[1] and either a showing that these parameters fit within the event limits in the Order or a justification for any deviation. The utility shall also identify the

[1] PJM Interconnection, L.L.C., PJM Manual 19: Load Forecasting and Analysis (2026), https://www.pjm.com/-/media/DotCom/documents/manuals/m19.pdf

portion of its VPP Interim Program it will include in each PSA, including any barriers and how it proposes to resolve them.[2]

5. Forecast: the estimated forecast reduction in its peak load contribution from each PSA plan.

6. Sharing with the Board: the utility shall file a copy of each PSA plan with the Board on the same day it submits the plan to PJM. If the plan contains confidential information, the utility may request confidential treatment under applicable rules.

b. The utility shall provide the following information about the proposed portfolio:

i. Quality assurance and control standards and remediation policies: The utility shall provide a detailed description of the process(es) for ensuring the quality of the programs and resolving any customer complaints related to the program(s).

ii. Customer access to current and historic energy usage data, including the process and timeframe by which the utility will make such data available to a Host Customer's authorized VPP Provider.

iii. Total budget summary, including an annual budget summary and joint budgets with partner utilities.

iv. Benefit-cost analysis (as defined in Section V).

v. The utility shall list its forecasted average cost to achieve each unit of peak demand savings in each sector.

vi. Marketing plan:

1. The utility shall provide a description of where and how the proposed portfolio will be marketed or promoted to the sectors served by the utility's customer base. This shall also include the marketing plan to outreach to low- and moderate-income (LMI) and overburdened communities. Furthermore, the description shall address coordinated customer outreach on programs with other utilities and the utility's use of the PowerUp NJ branding.

2. This plan shall include an explanation of how the specific services, along with prices, incentives, and energy bill savings for the proposed portfolio, will be conveyed to customers, where available and applicable.

3. The marketing plan shall also include a description of any known market barriers that may impact implementation and strategies to address known market barriers.

[2] Id. At 39.

vii. Cybersecurity and customer data privacy: The utility shall provide a description of the standards, controls, and incident-response procedures applicable to its dispatch and DER management systems and to any VPP Provider or DERMS Provider interfacing with those systems, together with the customer consent and data-privacy protections applicable to enrolled customer data.

## III. Co-enrollment and Double-Compensation Safeguards

a. For any customer enrolled in the VPP Interim Program whose premise also has a resource in net energy metering, Block 1, another Board-approved storage incentive program, or a PJM wholesale market program, the utility shall propose the method for treatment of the associated revenue stream(s) and shall describe the safeguards that prevent double-compensation for the same service.

b. The utility shall describe the contractual and systems controls that give effect to the anti-double-counting directive in the Order, under which load reduction compensated under Block 1 or under a Triennium program may not simultaneously be counted toward the VPP Interim Program peak demand reduction target, and load reduction counted toward that target may not be compensated under Block 1 or a Triennium program.

c. A single device may not be enrolled in both the VPP Interim Program and Block 1. Where a Site has a battery enrolled in Block 1 and other devices enrolled in the VPP Interim Program through DER Providers (e.g., a smart thermostat), the utility shall describe how it will measure VPP Interim Program performance at the retail meter after removing the battery's charge and discharge, as measured at the battery, from both the baseline and the event load, as Section II.A.iii of the Order requires, consistent with the attribution method in Section VI(e). The utility shall also describe how a Host Customer may leave either component program to enroll in a future program without penalty, as the Order provides.

## IV. Cost Recovery Mechanism

The Order provides that all costs of the PowerUp NJ Program shall be recovered as an Operating Expense; that no cost shall be recorded to or recovered as capital investment unless the Board expressly approves a demonstrated capital investment that is necessary to implement the program; that no return shall be earned on Operating Expense; that customer incentive amounts are a sub-category of Operating Expense; and that recovery of Operating Expense is subject to a prudence standard. This Section specifies the showings the utility must make to support recovery on that basis.

a. The utility shall provide appropriate financial data for the proposed program(s), including estimated revenues and expenses for each year of operations and at the beginning and end of each year. The utility shall include pro forma income statements for the proposed program(s) for each year of operations and actual or estimated balance sheets at the beginning and end of each year of the program period.

b. The utility shall provide an express confirmation that no cost of the proposed program(s) is proposed for capital treatment. If the utility proposes any cost for capital treatment notwithstanding the Order, it shall identify that cost separately, state the amount, and provide a detailed justification why the investment is necessary to implement the program.

c. Operating Expense reporting schedule. The utility shall report its proposed and actual program costs in a single schedule using Operating Expense as the sole recovery category, with the following sub-categories reported beneath it:

    i. program administration and implementation;

    ii. customer incentives;

    iii. evaluation, measurement, and verification (“EM&V”);

    iv. marketing; and

    v. Other Operating Expenses, separately identified.

    The schedule shall be filed with the petition and updated in each Quarterly Report and Annual Report required by the Order. It shall disaggregate costs by sub-program, by performance year, and by whether the cost is incurred by the utility, by an Implementation Contractor, or by a third-party VPP Provider. For each cost sub-category, the utility shall provide a comparison of budgeted and actual expenditures, an explanation of material variances, and identification of costs shared with other Board approved programs. Amounts paid to each VPP Provider, and amounts paid directly to Host Customers, shall be separately identified and broken down by payment type. Each cost recovery filing shall also identify amounts recovered from ratepayers and reconcile those recoveries with actual program expenditures, including any resulting over or under recovery.

d. The utility shall provide detailed spreadsheets of the accounting treatment of the proposed cost recovery, including describing how costs will be amortized, which accounts will be debited or credited each month, and how the costs will flow through the proposed program cost recovery method. Consistent with the Order, Operating Expense shall be recovered in the same year it is paid out. Any proposed deferral, amortization period, or carrying cost is limited to Board-approved capital investment and shall be shown in a separate recovery schedule with supporting justification.

e. The utility shall provide a detailed explanation, with all supporting documentation, of the recovery mechanism it proposes to utilize for cost recovery of the proposed

program(s), which the Order provides shall be the applicable EDC component of the N.J.S.A. 48:3-98.1 recovery clause, together with any other mechanism the utility proposes. The utility shall state the proposed filing cadence and true-up procedure for Operating Expense.

f. The utility's petition for approval, including proposed tariff sheets and other required information, shall be verified as to its accuracy and shall be accompanied by a certification of service demonstrating that the petition was served on the New Jersey Division of Rate Counsel simultaneous to its submission to the Board.

g. The utility shall provide a rate impact summary by year for the proposed program(s) and a cumulative rate impact summary by year for all approved and proposed programs showing the impact of individual programs, based upon a revenue requirement analysis that identifies all estimated program costs and revenues for each proposed program on an annual basis. Such rate impacts shall be calculated for each customer class. The utility shall also provide an annual bill impact summary by year for each program, and an annual cumulative bill impact summary by year for all approved and proposed programs showing bill impacts on a typical customer for each class. Consistent with the Order, the bill impact analysis shall:

    i. Show gross costs only, without netting benefits, for the proposed customer class(es) over the life of the program costs; and

    ii. Be accompanied by a separate year-by-year showing of projected benefits, revenue requirement impacts, and bill impacts, including when savings are expected to flow through to customers.

h. The utility shall provide, with supporting documentation, a detailed breakdown of the total costs for the proposed program(s), identified by cost segment, consistent with the program cost categories enumerated in Section II(a)(ix) and the Operating Expense sub-categories in Section IV(c). This shall also include a detailed analysis and breakdown and separation of the embedded and incremental costs that will be incurred to provide the services under the proposed program(s), with all supporting documentation. Embedded costs are costs that are provided for in the utility's base rates or through another rate mechanism. Incremental costs are costs associated with or created by the proposed program that are not provided for in base rates or another rate mechanism.

i. The utility shall provide a detailed revenue requirement analysis that clearly identifies all estimated annual program costs and revenues for the proposed program(s).

j. If the utility is seeking carrying costs on any deferred balance associated with the proposed program(s), the filing shall include a description of the methodology, capital structure, and capital cost rates used by the utility, together with (i) a calculation of its current capital structure and the capital structure approved by the Board in its most recent electric base rate case, and (ii) a statement as to its allowed overall rate of return approved by the Board in that case. A utility not seeking carrying costs is not subject to this requirement.

k. The utility shall not include utility lost distribution revenue in the revenue requirement or cost recovery showings for these programs. Recovery of forgone revenue, if any, is governed by the mechanisms addressed in the Board's energy efficiency proceedings.

## V. Benefit-Cost Analysis

a. The utility shall conduct a benefit-cost analysis of each proposed program and of the portfolio using all six (6) benefit-cost tests: the Ratepayer Impact Measure ("RIM"), Total Resource Cost ("TRC"), Societal Cost Test ("SCT"), Program Administrator Cost Test ("PACT"), Participant Cost Test ("PCT"), and New Jersey Cost Test ("NJCT"), as those tests are defined in the Board's most recent cost test guidance under the Energy Efficiency dockets and, for any test not addressed in that guidance, in the current National Standard Practice Manual, as modified by the methodologies and assumptions Staff provides in Attachment F to the Order. RIM is the primary test. If the utility concludes that a specific test does not apply to a proposed program, it shall explain why, as the Order provides.

b. The utility must demonstrate how the results of the tests in Section V(a) support Board approval of the proposed program(s), including how each proposed program is designed to achieve a benefit-to-cost ratio greater than 1.0 under the primary test. If a proposed program does not reach 1.0, the utility shall explain why the program is nonetheless in the public interest, consistent with the Order.

c. Benefit items. The utility shall quantify and report each benefit line item listed in Table A-1, for each proposed program and for the portfolio. For each line item the utility shall report a value under every test in which the item applies, as shown in Table A-1. Where the utility concludes that a line item is not applicable to a proposed program, it shall report zero (0) and state the reason; it shall not omit the line item. For a line item marked "excluded," the checkmarks show the tests in which the item would normally apply; the utility shall report zero (0) for that item in every test.

Table A-1. Benefit line items and the tests in which each applies

| Benefit line item | NJCT | TRC | SCT | PACT | RIM | PCT |
|---|---|---|---|---|---|---|
| Avoided wholesale electric energy | ✓ | ✓ | ✓ | ✓ | ✓ | _ |
| Avoided wholesale electric ancillary services | ✓ | ✓ | ✓ | ✓ | ✓ | _ |
| Avoided wholesale electric capacity | ✓ | ✓ | ✓ | ✓ | ✓ | _ |
| Avoided electric transmission | ✓ | ✓ | ✓ | ✓ | ✓ | _ |

| Benefit line item | NJCT | TRC | SCT | PACT | RIM | PCT |
|---|---|---|---|---|---|---|
| Avoided electric distribution | ✓ | ✓ | ✓ | ✓ | ✓ | – |
| Electric energy DRIPE | ✓ | ✓ | ✓ | ✓ | ✓ | – |
| Electric capacity DRIPE (excluded) | ✓ | ✓ | ✓ | ✓ | ✓ | – |
| Avoided $CO_2$ damages | ✓ | – | ✓ | – | – | – |
| Avoided $NO_x$ damages | ✓ | – | ✓ | – | – | – |
| Avoided $SO_2$ damages | ✓ | – | ✓ | – | – | – |
| Non-energy benefit adder (excluded) | ✓ | – | ✓ | – | – | – |
| Low-income adder (excluded) | ✓ | – | ✓ | – | – | – |
| Participant incentive received | – | – | – | – | ✓ | ✓ |
| Participant bill savings | – | – | – | – | – | ✓ |

For each line item the utility shall state separately: (1) the quantity it reports, expressed in kW, kW-year, MWh, or tons as applicable; (2) the unit value (e.g., $/kW-year, $/kWh, or $/ton) applied; (3) the methodology used to derive that unit value and the source of every input to it; (4) the calculation method, including any coincidence factor, loss factor, line-loss adjustment, or performance adjustment applied; and (5) the test or tests in which the resulting value is included, with all supporting work papers.

d. Valuation. Attachment F to the Order sets out the cost test methodologies and assumptions for the VPP Interim Program. Where Attachment F prescribes an assumption, the utility shall use it. Where Attachment F provides an assumed value, the utility shall use that value or propose a different value with justification. For any benefit line item in Table A-1 or cost line item in Table A-2 that Attachment F does not address, the utility shall propose the methodology and the unit value it will apply. All proposed values are subject to Board approval as part of the petition, and the four (4) EDCs shall coordinate before filing so that, where possible, proposed values are common across utilities. For each proposed value, the utility shall provide:

    i. the derivation, with all inputs, formulas, and work papers, in electronic form with formulas intact;

    ii. the source of each input, identified by publication, date, and page or table;

    iii. the period the value covers, the escalation applied, and the discount rate applied, stated separately for any test that uses a different discount rate;

iv. the basis for any coincidence factor, loss factor, line-loss adjustment, or performance adjustment; and

v. a sensitivity showing the effect on each test result of a reasonable high and low value for that line item. Where a value is drawn from a source the Board has already approved, including the Board's most recent New Jersey Cost Test guidance, the utility shall identify that source rather than derive the value anew. Where two (2) or more utilities propose materially different values for the same line item, each shall explain the difference.

e. Cost items. The utility shall quantify and report each cost line item listed in Table A-2, for each proposed program and for the portfolio, on the same basis required by Sections V(c) and V(d). Program costs reported under this Section shall tie to the Operating Expense sub-categories reported under Section IV(c), and the utility shall provide a reconciliation between the two. As the Order provides, utility lost distribution revenue shall not be included as a program cost in any of the six (6) tests, and is shown in Table A-2 as excluded from every test. Any other line item marked "excluded" in Table A-2 shall be reported as zero (0) in every test.

For purposes of Table A-2:

i. Participant incentive payments are the amount paid to a Host Customer, either directly by the utility or its contractor or, for a Site enrolled by a Site Aggregator, as the portion of the utility's payment that the Site Aggregator passes through to the Host Customer;

ii. Program operating and implementation costs are the total Operating Expense reported under Section IV(c), comprising all five (5) sub-categories, less the amount reported as Participant incentive payments, and is not limited to the sub-category in Section IV(c)(i); and

iii. Participant incremental cost is the out-of-pocket cost borne by the Host Customer, net of any incentive reported as Participant incentive payments, and is not a program budget item. For the VPP Interim Program, participant incremental cost is treated as zero, because enrolled devices are already installed or are incentivized through other Board-approved programs.

iv. Rate of return: VPP Interim Program costs are recovered as Operating Expense with no return, so no rate of return is included in any test (Table A-2). If the Board approves a capital investment under Section IV(b), the utility shall show any associated return separately.

Table A-2. Cost line items and the tests in which each applies

| Cost line item | NJCT | TRC | SCT | PACT | RIM | PCT |
|---|---|---|---|---|---|---|
| Participant incentive payments | – | – | – | ✓ | ✓ | – |

| Cost line item | NJCT | TRC | SCT | PACT | RIM | PCT |
|---|---|---|---|---|---|---|
| Program operating and implementation costs | ✓ | ✓ | ✓ | ✓ | ✓ | – |
| Participant incremental cost (excluded) | ✓ | ✓ | ✓ | – | – | ✓ |
| Rate of return | – | – | – | – | – | – |
| Utility lost distribution revenue (excluded) | – | – | – | – | – | – |

f. Basic Generation Service ("BGS") auction flow-through showing: the utility shall demonstrate how reduced capacity and transmission costs attributable to the proposed program(s) flow through to customers by way of BGS auction offers. This showing explains how the capacity and transmission benefits in Table A-1 reach customer bills. It is not an additional benefit line item and shall not be added to any test. The showing shall specify:

   i. the load forecast and capacity obligation inputs used in the utility's BGS-related filings for the periods compared;

   ii. how the forecast peak demand reduction from the proposed program(s) is reflected in those inputs;

   iii. the period over which the reduction is expected to be reflected in BGS pricing and the reason for any lag;

   iv. the estimated bill impact on a typical residential customer resulting from the flow-through; and

   v. all supporting documentation and work papers. Where the utility cannot quantify a portion of the flow-through, it shall say so and explain why.

g. Worksheet**:** The utility shall provide a budget and benefit-cost worksheet that allocates the proposed program budget across the Operating Expense sub-categories in Section IV(c) and demonstrates, with all underlying math, assumptions, and justification, that each proposed program achieves the benefit-to-cost ratio required by Section V(b). The worksheet shall also include a crosswalk, in a single table, showing for each performance year how every projected dollar maps across the three (3) views used in this Attachment: the projected cost categories in Section II(a)(ix), the Operating Expense sub-categories in Section IV(c), and the cost line items in Table A-2. Each view shall reconcile to the same total. Any amount reported as capital cost under Section II(a)(ix)(1) shall be shown separately, with the justification required by Section IV(b).

h. Forecast peak demand and capacity savings shall be calculated using the most recent Technical Reference Manual ("TRM") approved by the Board. Verified savings shall be measured using the baseline methodology in Section VI(b). To the extent that a protocol does not exist or an alternative protocol is proposed for a

filed program, the utility must submit a savings methodology for the program or contemplated measure for approval by the Board.

i. For calculation of energy and capacity savings, as well as for benefit-cost calculations, the utility shall apply the applicable net-to-gross ("NTG") ratio and realization rates provided in the current TRM. To the extent that a NTG value does not exist or an alternative NTG value is proposed for a filed program, the utility must submit a NTG value for the program or contemplated measure for approval by the Board.

j. The utility may also provide any additional benefit-cost analysis that it believes appropriate with supporting rationales and documentation.

## VI. Evaluation, Measurement, and Verification ("EM&V")

a. **Description.** The utility shall describe the methodology, processes, and strategies for monitoring and improving program and portfolio performance related to the utility's targets established pursuant to the Quantitative Performance Indicators ("QPIs") in Section VII. The utility shall confirm that these methodologies, processes, and strategies conform with the current New Jersey EM&V guidance documents and standards. The utility shall also provide an EM&V budget consistent with those guidance documents and standards;

b. **Baseline.** The utility shall provide its proposed Site baseline methodology, including the number of reference days, the method of weather normalization and whether it applies to all customer classes, the treatment of Sites with seasonal load profiles, and the treatment of Sites with on-site generation or storage, including, for a Site with a battery enrolled in Block 1, the removal of the battery's charge and discharge from both the baseline and the event load. The methodology shall also explain how the baseline accounts for load changes caused by time-of-use rates or other programs, so that only reductions caused by VPP dispatch are counted. The utility's approved methodology applies until Staff approves the shared EM&V metrics developed by the EM&V subgroup, as the Order provides;

c. **Event definition and call protocol.** The utility shall state what constitutes an EDC Dispatch Event for measurement purposes, how event hours are recorded, and how test calls are distinguished from EDC Dispatch Events in the performance record;

d. **Measurement interval and data granularity.** The utility shall state the interval at which performance is measured, the data granularity retained, and the retention period for event-level performance data;

e. **Attribution.** The utility shall describe the method by which performance is attributed where more than one program serves the same Site or the same device, including where a device receives an incentive under Block 1, a Triennium program, or an electric vehicle charging program. The method shall give effect to the anti-

double-counting directive in the Order. Because a Site enrolled through DER Providers may have more than one DER Provider, and the utility pays the Host Customer for the Site's net load reduction and pays each DER Provider under its contract, the utility shall describe how it will measure the Site's load reduction at the retail meter and how it will track each DER Provider's reliability in providing device data and carrying out dispatch signals;

f. **Verification.** The Order provides that verification of program savings shall be performed by an independent evaluator retained by the Board. The utility shall describe the data, systems access, records, and personnel it will make available to that evaluator; the format and cadence in which it will supply event-level and settlement data; and its records retention practice. The utility shall not condition the evaluator's access on confidentiality terms that would prevent the evaluator from reporting its findings to the Board; and

g. **Program Midterm Review**. The utility shall describe how it will support the Midterm Review described in the Order, which covers the first twelve (12) months of operation, as defined in the Order, relies on the utility's Midterm Report required by the Order, and will assess program cost-effectiveness and performance against the peak demand reduction target established for the utility.

## VII. Quantitative Performance Indicators ("QPI")

a. The utility shall propose quantitative performance indicators ("QPIs") for the VPP Interim Program, consistent with the QPI framework the Board has adopted for the utility's energy efficiency and peak demand reduction programs.[3] For each proposed QPI the utility shall state the definition, the unit of measurement, the data source, the measurement frequency, and, for each target QPI marked "target" in Section VII(b), the proposed target for each performance year. QPIs are reporting and accountability measures. They are not compliance thresholds and carry no financial consequence;

b. At a minimum, the utility shall propose QPIs covering the following. Items marked "target" require a target for each performance year; items marked "tracking" are reported without a target:

    i. number of enrolled devices, Sites, and Host Customers, by DER type and VPP Provider path (tracking);

    ii. number of enrolled devices and enrolled kW by ZIP code and, where the utility has identified them, on constrained circuits, aggregated to protect customer privacy (tracking).

    iii. MW of load under management, meaning the total controllable load, expressed in MW, of enrolled devices available for dispatch (target);

[3] In re the Implementation of P.L. 2018, c. 17, the New Jersey Clean Energy Act of 2018, Regarding the Second Triennium of Energy Efficiency and Peak Demand Reduction Programs, BPU Docket No. QO23030150, Order dated May 24, 2023.

iv. MW of verified load reduction during PJM's five (5) coincident peaks hours ("5CP"), calculated as the average of the verified load reduction in each 5CP hour, with a value of zero (0) for any 5CP hour in which no event was called, measured once per performance year after PJM publishes the 5CP hours (target);

v. percent peak shaving, calculated as the verified load reduction reported under Section VII(b)(iv) divided by the utility's service-territory peak load, using the same peak-load basis as the target under Section II(a)(xv) (target);

vi. cost to achieve, expressed in dollars per kW and calculated as the total program costs for the performance year, as reported under Section IV(c), divided by the verified load reduction reported under Section VII(b)(iv) (target);

vii. event response rate (verified kW delivered divided by kW dispatched) and Host Customer opt-out rate (the number of enrolled devices whose Host Customer opts out of or overrides the event at any time during the event, divided by the number of enrolled devices dispatched for that event; a device that does not respond because of a communication or equipment failure is not an opt-out and is reflected in the event response rate), each reported for every EDC Dispatch Event, including events reported under Section VII(b)(ix) (tracking);

viii. The number and percentage of enrolled customer accounts held by low- and moderate-income ("LMI") customers and by customers in overburdened communities ("OBC"), using enrollment in an income qualified program as the LMI indicator and the overburdened community designation of the customer's service address, or another proxy the utility proposes (tracking);

ix. MW of verified load reduction for each EDC Dispatch Event and duration that does not include a 5CP hour, as determined after PJM publishes the 5CP hours, including winter-season events, grid stress events, and events called to address distribution-level constraints, reported by event and by event type, and not counted toward the QPIs in Section VII(b)(iv) – (vi) (tracking); and

x. Average verified load reduction across the PSA hours in the performance year, meaning all hours in which the trigger in the utility's PSA plan under Section II(a)(xxiii)(4) was met, plus any pre-trigger window that the PSA plan defines consistent with PJM requirement, with a value of zero (0) for any PSA hour in which no event was called, reported together with the forecast reduction in the utility's PSA plan under Section II(a)(xxiii)(5) (tracking).

c. The utility shall state how each proposed QPI target relates to the peak demand reduction and cost savings targets proposed under Sections II(a)(xv) and II(a)(xvi) and to the forecast table required by Section II(a)(xvii).

## VIII. Reporting Plan

The reporting requirements for the VPP Interim Program, including the Quarterly Report, the Event-Level Report, and the Annual Report (the first of which is also the Midterm Report), are set forth in the Order.

# Attachment B

In the Matter of Establishing the PowerUp New Jersey Program, Docket No. QO26100658

In the Matter of Advancing a Virtual Power Plant (VPP) Program in the State of New Jersey Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program – Phase 2 Distributed Storage, Docket No. QO26040116

MINIMUM FILING REQUIREMENTS FOR THE GARDEN STATE ENERGY STORAGE PROGRAM, PHASE 2 BLOCK 1 UNDER N.J.S.A. 48:3-87.8

The Garden State Energy Storage Program ("GSESP") Phase 2, Block 1 Program ("Block 1") is a component program of the Power Up NJ Program established by the Order to which this Attachment is appended ("Order"). Each electric distribution company ("EDC" or "utility") shall file a petition proposing its Power Up NJ Program no later than February 12, 2027. This Attachment sets the minimum filing requirements ("MFRs") each petition shall include with respect to the Block 1. The MFRs for the VPP Interim Program are set forth in Attachment A.

Program parameters referenced in these requirements – including the event dispatch performance-based incentives, cost recovery, event dispatch parameters– are established in the Order and are not restated here.

## I. General Filing Requirements

a. The EDC shall provide a table of contents and page numbering for each filing.

b. The EDC shall provide with all filings, information and data pertaining to the specific program proposed, as set forth in applicable sections of N.J.A.C. 14:1-5.11 and N.J.A.C. 14:1-5.12.

c. All filings shall contain information and financial statements for the proposed program(s) in accordance with the applicable Uniform System of Accounts that is set forth in N.J.A.C. 14:1-5.12. The EDC shall provide the accounts and account numbers that will be utilized in booking the revenues, costs, expenses, and assets pertaining to each proposed program so that they can be properly separated and allocated from other regulated programs and/or other programs.

d. The EDC shall provide supporting explanations, assumptions, calculations, and work papers as necessary for each proposed program and cost recovery mechanism petition filed. The EDC shall provide electronic copies of such supporting information, with all inputs and formula intact, where applicable.

e. The filing shall include testimony supporting the petition, including all proposed programs.

f. For any proposed program, the EDC shall be subject to the requirements in this and all subsequent Sections. If compliance with Section V or Section VI of this

Attachment would not be feasible for a particular program or sub-program, the EDC may request an exemption but must demonstrate why such exemption should be granted. Examples of historical situations that have qualified for exemption include pilot programs, programs that had an educational or policy goal rather than resource acquisition focus, and programs that introduced novel ideas where documentation supporting estimated costs/benefits may not be easily produced. No exemption is available from the cost recovery filing requirements in Section IV.

g. If the EDC is filing for an increase in rates, charges, etc. or for approval of a program that may increase rates/charges to ratepayers in the future, the EDC shall include a draft public notice with the petition and proposed publication dates.

II. **Program Description**

a. The EDC shall provide a detailed description of how it will implement and administer the Block 1 program in compliance with the Board-established program framework including;

i. **Program Description/Design**: The EDC shall describe how it will implement and administer the Block 1 program within its service territory, including organizational responsibilities, administration of Board-established program requirements, and overall approach to program delivery. The filing shall include all proposed implementation documents, forms, agreements, notices, and procedures necessary to administer the Block 1 program.

ii. **Target Market Segment:** Describe the procedures the EDC will use to verify compliance with all Board-established eligibility requirements including but not limited to customer eligibility, project eligibility, technical requirements, operational requirements, interconnection requirements, device level metering, and participation structures involving Host Customers, DER Providers (as defined in the Order), and other authorized representatives.

iii. **Existing Incentives and Programs:** Describe how the EDC will coordinate with the VPP Interim Program, manage the transition from Triennium II programs to the Block 1 program, prevent duplicative compensation, and establish procedures governing transitions between Block 1 and other Board-approved programs.

iv. **Proposed Incentive Structure:** Describe how the EDC will administer the Board-established performance-based incentive framework, including but not limited to the calculation of annual incentive payments, verify Awarded Storage Capacity and Performance Factors, disburse payments, and administer payment dispute resolution procedures.

v. **Participant Ownership and Contractual Agreements:** The EDC shall facilitate and monitor the relationship between the various parties participating in Block 1. Specifically, the EDC shall:

a) Describe how the EDC will administer participation by Host Customers, DER Providers, and other authorized representatives, including the documentation required to demonstrate customer authorization, operational control, enrollment authority, incentive payment rights, customer disclosures, and responsibility for customer communications and support.

b) Describe how the EDC will monitor Host Customer rate and supply arrangements, including enrollment under Basic Generation Service – Residential Small Commercial Pricing, Third Party Supply, Time of Use rates, and other applicable tariff structures, and how such information will be incorporated into program administration.

vi. **Contractor Requirements and Role:** The EDC shall provide a description of the extent to which the EDC intends to utilize employees, contractors, or both to deliver the Block 1 program. The EDC shall also provide a description of contractor requirements, including common application elements and training requirements.

vii. **Estimated Program Participation by Year:** The EDC shall provide annual forecasts of applications, deployed capacity, number of Host Customers participating in Block 1, and any other metrics necessary for the Board to evaluate the EDC's implementation of the Block 1 program. The EDC shall also provide its own estimate of how much existing storage capacity within its service territory can be enrolled in the program to the extent that it disagrees with the existing storage capacity allocation recommended by Staff.

viii. **Peak Demand Savings:** The EDC shall provide projections for peak demand savings, enrolled systems, financial savings generated, and associated metrics for each program year relative to the quantitative performance indicators in Section VII.

ix. **Program Budget, by Year:** The EDC shall provide an annual budget for administration of Block 1, including but not limited to program administration, dispatch event notification, performance verification, customer engagement, information technology systems, incentive payments, interconnection support activities, reporting, and other associated program costs.

x. **Program Costs:** The EDC shall provide program costs, by year, broken down into the categories listed below and include with each a detailed description, further breakdown, and justification of the amount, as applicable: To the extent the EDC proposes capital investments necessary to administer Block 1, the filing shall describe the proposed investment, demonstrate why the investment is required to administer the Board-approved program, explain how the investment is aligned with the EDC's Proactive System Upgrade Plan ("PSUP"), identify

alternatives considered, and describe the proposed accounting and ratemaking treatment. The filing shall explain the basis for each cost category and demonstrate that the associated expenditures are reasonable and necessary.

a) Capital Cost if the EDC proposes capital investments

b) Utility administration and program implementation administration

c) Marketing and customer engagement

d) Outside services with a detailed description of such costs

e) Incentive payments, including performance measurement and verification activities

f) Inspection and quality control

g) Evaluation, measurement, and verification ("EM&V")

h) Any other costs associated with implementation and administration of the program.

xi. **Event Dispatch Protocol and Notification Timeline**: The EDC shall demonstrate that its proposed event dispatch protocol and notification timeline conform to the EDC Dispatch Event parameters established in the Order or justify any proposed deviation **by** specifying how the proposed deviation will result in greater ratepayer savings than the parameters established in the Order. The EDC shall also describe the capability of its dispatch platform to segment enrolled resources by locational node, technology type, and response capability.

xii. **Enabling Infrastructure:** The EDC shall provide a description of the infrastructure, systems, and capabilities necessary to administer GSESP Phase 2, Block 1, including performance measurement methodology, device-level data collection capabilities, dispatch communication methods, Participant notification systems, and interconnection and cybersecurity requirements. The filing shall also identify any infrastructure constraints that could limit program implementation or deployment of the EDC's allocated Block 1 capacity and any planned investments or system enhancements needed to support the administration and objectives of Block 1, and any infrastructure constraints that might limit a Block 1 participant from transitioning to a future VPP program. EDCs proposing capital investments shall provide supporting justification demonstrating why such investments are necessary to administer the program. EDCs shall also clearly note and separate out the cost of any enabling infrastructure that the EDC is recovering or will recover outside of Block 1.

xiii. **Dispatch Event Plan:** The EDC shall provide a detailed plan outlining the methodology an EDC will use to forecast PJM's Capacity 5 Coincident Peaks and Transmission 1 Coincident Peak periods and establish Dispatch Events in order to effectively reduce capacity and transmission costs to the zone, as well as the types of distribution-level events for which the EDC intends to dispatch Block 1 resources for.

xiv. **Net Metering (NEM) and Export Capability:** The EDC shall describe how it will implement the requirements outlined in the Order regarding the interconnection and operation of export-capable energy storage systems, including, standalone storage systems and those paired with onsite solar, consistent with the Board's interconnection regulations set forth at N.J.A.C. 14:8-5.1 through N.J.A.C. 14:8-5.13. The filing shall explain the process by which new and existing behind-the-meter storage resources may obtain authorization to export energy to the grid, including through the submission of new interconnection requests where applicable. The EDC shall further demonstrate how eligible solar-plus-storage systems configured in accordance with the Order's requirements, including systems operating in "NEM Integrity" mode, will be permitted to export energy and receive net metering credits. EDCs should describe the anticipated time, cost, and process for interconnection reviews for existing resources. The EDC shall also propose a streamlined interconnection review process for existing solar-plus-storage systems that seek permission to export from their storage component and propose to use export controls to limit the system's total export capacity to their currently studied export capacity. This process should waive the requirement for such an existing system to undergo a new interconnection study unless the EDC explains why not conducting new interconnection studies for such systems could endanger the safe and reliable operation of the distribution system.

xv. **Performance Measurement Plan:** Additionally, the EDC should describe their proposed procedures for collecting, analyzing, and validating device-level performance data; calculating Dispatch Event Minimum Output, system Performance Factors, and annual incentive payments; administering audits and disputes; and verifying compliance with program requirements.

xvi. **Peak Demand Reduction Target:** If the EDC disagrees with the Peak Demand Reduction Values suggested by Staff, the EDC should provide a new target, expressed in MW, for each Performance Year of the Block 1 program. The EDC must justify any alternative Peak Demand Reduction target it proposes and include the assumptions underlying its proposed target. If the EDC does not provide a new target, it shall abide by the targets set forth in this Order.

xvii. **Forecast Table:** A table, organized by year, presenting forecasted values for the number of enrolled Host Customers; total energy storage capacity under management (kW or MW); projected average energy storage discharge in kW across Capacity 5 Coincident Peaks and Transmission 1 Coincident Peak; program budget; cost to achieve

($/kW); percent peak shaving (energy storage discharge divided by total peak); and forecasted verified savings by avoided-cost line item as specified in Section V(c).

xviii. **Implementation Schedule:** A schedule, with key milestones from Board approval through the final Performance Year of the program demonstrating that the program will be open for enrollment no later than sixty (60) days following Board approval of each EDC's petition. Key milestones should include program launch date, dispatch and performance verification readiness, timelines for interconnection of storage assets, dates for achieving the capacity allocation amounts outlined in the Board Order, and any other relevant milestones needed to ensure successful, timely implementation and administration of the program. For each major milestone, the EDC should provide the target date, and corrective actions if the milestone is missed.

xix. **Applicable Standards:** A description of how the program will comply with the applicable standards and guidelines established by the Board, including those governing information sharing and transparency, Participant conduct, cybersecurity, and marketing and public engagement.

b. **Portfolio-level Administrative Requirements:** Each EDC shall also provide the following portfolio-level information;

i. **Quality Assurance, Control, and Remediation:** The EDC shall provide a detailed description of the process(es) ensuring the Block 1 program meets its stated objectives and for resolving any customer complaints related to the program.

ii. **Market Participation and Contracting Opportunities:** The EDC shall describe how it will support participation by DER Providers, underrepresented and disadvantaged workers, and other market participants involved in the deployment and operation of energy storage systems under the Block 1 program. The filing shall describe any contractor engagement strategies, procurement processes, and workforce development considerations needed to implement and administer the Block 1 program. Additionally, the EDC shall describe how it intends to ensure an easy to navigate experience for participation beginning with enrollment and interconnection through program operations.

iii. **Host Customer Access to their System's Performance Data:** The EDC shall describe the process and timeframe by which the EDC will make system performance data available to both the Host Customer and the DER Provider.

iv. **Total Budget Summary:** The EDC shall include an annual budget summary and, if applicable, joint budgets with partner utilities.

v. **Benefit-Cost Analysis:** The EDC shall include benefit-cost analyses that meet the requirements specified in in Section IV.

vi. **Forecasted Average Cost:** The EDC shall state its forecasted average cost to achieve each unit of peak demand savings.

vii. **Marketing and Outreach Plan:**

a) The EDC shall describe how it will educate and engage DER Providers and Host Customers regarding Block 1 participation and program requirements. The filing shall include a plan for coordinating with DER Providers on customer acquisition and enrollment strategies, developing customer education materials, identifying customer points of contact, and resolving customer complaints.

b) The marketing plan shall include an explanation of how the specific program offerings and incentives, as well as other benefits of installing energy storage, will be communicated to potential Host Customers. The marketing plan shall also include a description of how the EDC plans to communicate the benefits of the Block 1 program to non-participants.

c) The marketing plan shall also include a description of any known market barriers that may impact implementation and strategies to address known market barriers.

viii. **Cybersecurity and Customer Data Privacy:** The EDC shall provide a description of the standards, controls, and incident-response procedures applicable to its dispatch and notification systems and to any third-party operator interfacing with those systems, together with the customer consent and data-privacy protections applicable to enrolled customer data.

III. **Cost Recovery Mechanism**

a. **Financial Data:** The EDC shall provide appropriate financial data for the proposed program(s), including estimated revenues, expenses, and incentive obligations and payments, and capital investments, if applicable, for each Performance Year of the full anticipated program life. The EDC shall include pro forma income statements for the proposed program(s) for each Performance Year and actual or estimated balance sheets at the beginning and end of each year of the program period.

a. **Accounting Treatment:** The EDC shall provide detailed spreadsheets describing the accounting treatment that will be used to record and track all Block 1 costs, revenues, incentive payments, administrative expenses, and capital investments. The filing shall identify the applicable accounts, accounting procedures, reconciliation procedures, and cost-tracking methodologies that will be used to separately account for Block 1-related activities. Block 1 costs and revenues shall be separately identifiable from VPP

Interim costs and revenues, Triennium program costs and revenues, base rates, and other recovery mechanisms. For shared expenditures, the EDC shall identify the allocation methodology and supporting cost drivers and demonstrate that no expenditure is recovered more than once.

b. **Cost Recovery Framework and Timeline:** The EDC shall describe how it will implement the Board-approved cost recovery framework, including proposed recovery through a separately identified Block 1 component within its applicable Board approved recovery clause established within its RGGI Rider. The filing shall describe the proposed recovery structure, reconciliation process, and any tariff modifications necessary to recover approved program administration and incentive costs. The EDC shall also provide a detailed timeline for recovery of all Block 1 costs. Utilities will describe how incentive costs will be recovered in the Performance Year in which costs are incurred so as to avoid the need for carrying costs. The EDC shall demonstrate that the same cost is not already recovered through base rates, Triennium programs, VPP budgets, AMI approvals, grid-modernization proceedings, or another mechanism.

c. **Petition for Approval:** The utility's petition for approval, including proposed tariff sheets and other required information shall be verified to its accuracy and shall be accompanied by a certification of service demonstrating that the petitions were served on the New Jersey Division of Rate Counsel simultaneous to its submission to the Board.

d. **Rate and Bill Impacts:** The EDC shall provide projected rate and bill impacts associated with recovery of Block 1 costs, including estimates by customer class and a description of the assumptions used to develop those projections. The EDC shall also provide an annual bill impact summary by year for all approved and proposed programs showing bill impacts on a typical customer for each class.

e. **Total Costs:** The EDC shall provide a detailed breakdown of the total costs of the Block 1 program, identified by cost segment, consistent with the program cost categories enumerated in Section II – x. above. This shall include detailed analysis and breakdown and separation of the embedded and incremental costs that will be incurred to provide the services under the proposed program, with all supporting documentation. Embedded costs are costs that are provided for in the utility's base rates or through another rate mechanism. Incremental costs are costs associated with or created by the proposed program that are not provided for in base rates or another rate mechanism.

f. **Revenue Requirement Analysis:** The EDC shall provide a detailed revenue requirement analysis that clearly identifies all estimated annual program costs and revenues for the Block 1 program, including effects upon rate base and pro forma income calculations.

g. **Capital Structure:** While the program design seeks to avoid the need for capital costs, if the EDC proposes recovery of capital investments with a return or carrying costs calculated using its cost of capital, the EDC shall provide, with supporting documentation: (i) a calculation of its current capital structure, as

well as its calculation of the capital structure approved by the Board in its most recent electric and/or gas base rate cases, and (ii) a statement as to its allowed overall rate of return approved by the Board in its most recent electric and/or gas base rate cases.

h. **Carrying Costs:** While the program design seeks to avoid the need for carrying costs as a mechanism to minimize total program costs, should the EDC seek carrying costs for the program, the filing shall include a description of the methodology, capital structure and capital cost rates used by the utility, as well as a justification for doing so.

IV. **Benefit-Cost Analysis**

a. The EDC shall conduct a benefit-cost analysis of the Block 1 program, using the methodologies detailed in Attachment G. This includes six tests with assumptions and methodologies specific to GSESP Phase 2 Block 1: the Ratepayer Impact Measure ("RIM"), the Total Resource Cost ("TRC"), the Societal Cost Test ("SCT"), the Program Administrator Cost Test ("PACT"), the Participant Cost Test ("PCT"), and the New Jersey Cost Test ("NJCT").

b. For the most part, the EDC will compute BCAs using assumptions prescribed by Staff based on publicly available information and determinations based on program design. For certain assumptions, however, Staff has provided assumed values that the EDC may propose to modify where they are better positioned to develop more accurate estimates, subject to reasonable justification. Where the EDC proposes its own assumptions, it shall:

    i. Provide a sensitivity showing the effect on each test result of a reasonable high and low value for that line item; and

    ii. Provide the assumption's derivation methodology, including the source and workpapers with all inputs and formulas in electronic form with formulas intact.

c. The EDC shall demonstrate how reduced energy, capacity, and transmission costs attributable to the proposed program(s) flow through to customers. The showing shall specify:

    i. the load forecast and capacity obligation inputs used in the utility's BGS-related filings for the periods compared;

    ii. how the forecast peak demand reduction from the proposed program(s) is reflected in those inputs;

    iii. the period over which the reduction is expected to be reflected in BGS pricing and the reason for any lag;

    iv. the estimated bill impact on a typical residential customer resulting from the flow-through; and

v. where the EDC cannot quantify a portion of the flow-through, it shall say so and explain why.

d. The EDC must demonstrate how the results of the tests in Section IV(a) support Board approval of the Block 1 program, including how the program is designed to achieve a benefit-to-cost ratio greater than or equal to 1.0 when using the RIM test. The RIM test shall serve as the primary BCA test for the Program. Results from the other BCA tests are intended to provide additional perspectives on program costs and benefits and should not be interpreted in isolation as determining whether the Bock 1 Program is beneficial to New Jersey ratepayers, supports the objectives of PowerUP NJ, or advances the transition to a future Virtual Power Plant (VPP) framework. Accordingly, an individual test result below 1.0 does not, in itself, indicate that the Program lacks overall value or should not proceed.

e. If the proposed program does not reach 1.0, the EDC shall explain why the program is nonetheless in the public interest, consistent with the Order.

f. Benefit items: The utility shall quantify and report each benefit line item listed in Table B-1, for each proposed program. For each line item the utility shall report a value under every test in which the item applies, as shown in Table B-1, and shall follow the methodology described in Attachment G.

g. The EDC may also provide any additional benefit-cost analysis that it believes appropriate with supporting rationales and documentation.

h. A summary of the relevant cost/benefit categories is found in Tables B-1 and B-2 below, with detailed definitions and methodologies explained in Attachment G.

Table B-1. Benefit line items and the tests in which each applies

| **Benefit line item** | **NJCT-** GSESP | **TRC-** GSESP | **SCT-** GSESP | **PACT-** GSESP | **RIM-** GSESP | **PCT-** GSESP |
|---|---|---|---|---|---|---|
| Avoided wholesale electric energy | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Avoided wholesale electric ancillary services | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Avoided wholesale electric capacity | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Avoided electric transmission | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Avoided electric distribution | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |

| **Benefit line item** | **NJCT-** GSESP | **TRC-** GSESP | **SCT-** GSESP | **PACT-** GSESP | **RIM-** GSESP | **PCT-** GSESP |
|---|---|---|---|---|---|---|
| Electric energy DRIPE | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Electric capacity DRIPE | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Avoided CO2 damages | – | – | ✓ | ✓ | – | – |
| Avoided NOx damages | – | – | ✓ | ✓ | – | – |
| Avoided SO2 damages | – | – | ✓ | ✓ | – | – |
| Non-energy benefit adder | – | – | – | – | – | – |
| Low-income adder | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* |
| Participant incentive received | – | – | – | – | ✓ | ✓ |
| Participant bill savings | – | – | – | – | – | ✓ |
| Avoided wholesale natural gas and delivered fuel | ✓ | ✓ | ✓ | ✓ | ✓ | – |
| Avoided RPS REC purchase costs | – | ✓ | ✓ | ✓ | ✓ | – |
| Avoided wholesale volatility costs | – | ✓ | ✓ | ✓ | – | – |
| Job and savings multiplier benefits | – | – | ✓ | – | – | – |
| Participant avoided retail natural gas | – | – | – | – | – | ✓ |
| Participant time-value of loan repayments | – | – | – | – | – | ✓ |
| | | | | | | |

Table B-2. Cost line items and the tests in which each applies

| Cost line item | NJCT-GSESP | TRC-GSESP | SCT-GSESP | PACT-GSESP | RIM-GSESP | PCT-GSESP |
|---|---|---|---|---|---|---|
| Participant incentive payments | ✓ | ✓ | – | ✓ | ✓ | – |
| Program administration and implementation costs | ✓ | ✓ | ✓ | ✓ | ✓ | – |
| Participant incremental cost | – | – | – | – | – | ✓ |
| Rate of return | – | – | – | – | – | – |
| Utility lost distribution revenue | – | – | – | – | ✓ | – |
| Time-value of loan repayments | – | – | – | ✓ | ✓ | – |
| Cost-to-service loans | – | – | – | – | – | – |

V. **Evaluation, Measurement, and Verification ("EM&V")**

a. The EDC shall describe the methodology, processes, and strategies for monitoring and improving program and portfolio performance related to the EDC's targets established pursuant to the Quantitative Performance Indicators ("QPIs") in Section VI. The EDC shall confirm that these methodologies, processes, and strategies conform with the current New Jersey EM&V guidance documents and standards. If the EDCs find that these methodologies, processes, and strategies are not applicable to the Block 1 program, they should provide a written justification as to why they are not applicable. The EDC shall also provide an EM&V budget consistent with the current New Jersey EM&V guidance documents and standards.

VI. **Quantitative Performance Indicators**

a. The EDC shall propose quantitative performance indicators ("QPIs") for Block 1, consistent with the framework set forth below. For each proposed QPI, the utility shall state the definition, the unit of measurement, the data source, the measurement frequency, and the proposed target for each program year;

b. At a minimum, the utility shall propose QPIs covering:
   i. Number of enrolled energy storage systems and enrolled customer accounts as well as total applicants;

ii. Length of time for applicants to receive interconnection approval;

iii. MW of energy storage capacity under management;
iv. MW of verified energy storage discharge during PJM's coincident peaks, both capacity and transmission;

v. Cost to achieve, expressed in dollars per kW of verified energy storage discharge during PJM's coincident peaks, both capacity and transmission;

vi. Event response rate and customer opt-out rate;

vii. Capacity obligation and transmission charge reductions resulting from verified coincident peak load reductions due to energy storage discharge, and the resulting estimated avoided costs to customers.

viii. Avoided distribution system costs attributable to program performance

c. The EDC shall state how each proposed QPI target relates to the peak demand reduction proposed under Section II(a)(xiii) and to the forecast table required by Section II(a)(xiv), in line with the targets outlined in the Board Order.

VII. **Reporting Plan**

a. The EDC shall comply with the reporting requirements as outlined in the body of this order.

# Attachment C

In the Matter of Establishing the PowerUp New Jersey (PowerUp NJ) Programs

Docket No. QO26100658

In the Matter of Advancing a Virtual Power Plant (VPP) Program in the State of New Jersey

Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program Pursuant to P.L. 2018, c. 17

Docket No. QO22080540

Staff released a VPP Straw Proposal on July 15, 2026, under the docket No. QO26030099, with a 30-day comment period. Comments were due at 5 P.M. on August 17, 2026. The Board received a total of 75 comments from stakeholders. The stakeholders who commented on the Straw Proposal have been organized into the following categories. Staff assigned each commenter to one category. Where a commenter identified its role or sector in its comments, Staff used that self-identification. Where it did not, Staff assigned a category based on publicly available information about the organization, such as its public website. Where a commenter could fit more than one category, Staff placed it in the category that best reflects its primary role and comments in this proceeding.

Categories of stakeholders:

A. Utilities and Utilities Association – 6 commenters
   1. Atlantic City Electric Company (“ACE”)
   2. Jersey Central Power & Light Company (“JCP&L”)
   3. New Jersey Natural Gas Company (“NJNG”)
   4. New Jersey Utilities Association (“NJUA”)
   5. Public Service Electric and Gas Company (“PSE&G”)
   6. Rockland Electric Company (“RECO”)

B. Division of Rate Counsel – 1 commenter
   7. New Jersey Division of Rate Counsel (“Rate Counsel”)

C. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.) – 34 commenters
   8. Calibrant Energy (“Calibrant”)
   9. DCO Energy, LLC (“DCO”)
   10. Edge Zero
   11. Edgeli Inc. d/b/a CapacitiMap (“Edgeli”)
   12. Electrify America, LLC (“Electrify America”)
   13. EnergyHub, Inc. (“EnergyHub”)

14. ev.energy
15. Foley, Incorporated (“Foley”)
16. Honeywell Technologies (“Honeywell”)
17. Koolbridge Energy, Inc. (“Koolbridge”)
18. Logical Buildings
19. Lunar Energy, Inc. (“Lunar”)
20. ModernElectric Inc. (“ModernElectric”)
21. Nexamp
22. NJR Clean Energy Ventures Corporation (“NJRCEV”)
23. Oracle
24. PACE AI
25. Piclo, Inc. (“Piclo”)
26. Recurve Analytics, Inc. (“Recurve”)
27. Renew Home
28. RExChain LLC (“RExChain”)
29. RIC Energy
30. Solar Landscape
31. Soltage
32. Steffes, LLC (“Steffes”)
33. SunStrong Management, LLC (“SunStrong”)
34. Tesla, Inc. (“Tesla”)
35. Tri-State Energy, Inc. (“Tri-State”)
36. Turtle & Hughes, Inc. (“Turtle & Hughes”)
37. Uplight
38. UtilityAPI, Inc. (“UtilityAPI”)
39. Virtual Peaker, Inc. (“Virtual Peaker”)
40. Voltus, Inc. (“Voltus”)
41. WeaveGrid

D. Trade Associations – 9 commenters
42. Advanced Energy United
43. BTM Coalition (Sunrun, GoodLeap, Tesla, IGS Energy, EnergyHub, Enphase, Generac, and Scale Microgrids)
44. ChargEVC
45. Solar Energy Industries Association, Coalition for Community Solar Access, and New Jersey Solar Energy Coalition (“SEIA/CCSA/NJSEC”)
46. Energy Efficiency Alliance of New Jersey (“EEA-NJ”)
47. Mission:data Coalition (“Mission:data”)
48. New Jersey Clean Capacity Coalition (“NJCCC”)
49. Smart Thermostat Coalition
50. Vehicle-Grid Integration Council (“VGIC”)

E. Advocacy Groups – 10 commenters
   51. American Council for an Energy-Efficient Economy (“ACEEE”)
   52. Ceres, Inc. (“Ceres”)
   53. Climate Jobs New Jersey (“CJNJ”)
   54. Evergreen Action and the Environmental Defense Fund (“Evergreen Action and EDF”)
   55. New Jersey Environmental Justice Alliance (“NJEJA”)
   56. New Jersey League of Conservation Voters (“New Jersey LCV”)
   57. NJ Electrification Coaching Network (“NJECN”)
   58. Northeast Energy Efficiency Partnerships (“NEEP”)
   59. Sierra Club
   60. Vote Solar

F. Program Implementers and Administrators – 5 commenters
   61. Ampion, PBC (“Ampion”)
   62. Energy Solutions
   63. MaGrann Associates (“MaGrann”)
   64. Michaels Energy
   65. Power TakeOff

G. Third-Party Suppliers – 2 commenters
   66. Base Power Company (“Base Power”)
   67. NRG Energy, Inc. (“NRG”)

H. Government Agencies – 1 commenter
   68. South Monmouth Regional Sewerage Authority (“SMRSA”)

I. Financial Services – 1 commenter
   69. Syntropic Capital Partners, LLC (“Syntropic”)

J. Individuals and Academic Institutions – 6 commenters
   70. Bill Beren
   71. Cammie Croft
   72. Michael Winka
   73. Satya Vithala of Digital Verity LLC (“Digital Verity”)
   74. Evaporcool Solutions LLC d/b/a Peak+ (“Peak+”)
   75. University of Delaware EV Group (“UDelaware”)

The commenters’ feedback was categorized into the following topics, based on the applicable section(s) of the VPP Straw Proposal:

1. **Program Foundation & Objectives**: *Straw Proposal Executive Summary, § 1.1–1.4, § 2.1; Stakeholder Comment No. 1*
2. **Eligibility & Enabling Technology**: *Straw Proposal § 2.2, § 2.3, § 4.6; Stakeholder Comment Nos. 2, 3, 26*
3. **Budget, Targets & Cost-Effectiveness**: *Straw Proposal § 2.1(i), § 2.4, § 2.6, § 2.7, § 2.9(iii), Appendix A; Stakeholder Comment Nos. 4, 5, 6, 8, 9*
4. **Dispatch & Operations**: *Straw Proposal § 2.5, § 2.6; Stakeholder Comment No. 7*
5. **EDC-Aggregator Relationships and Interim Filings**: *Straw Proposal § 2.2(i), § 2.8, § 2.9; Stakeholder Comment Nos. 10, 11, 12, 13*
6. **Long-Term Transition, Tariff & Compensation**: *Straw Proposal Section 3 introduction, § 3.1–3.7; Stakeholder Comment Nos. 14, 15, 16, 17, 18, 19, 20*
7. **Cross-Program Coordination**: *Straw Proposal § 3.2, § 4.1–4.5, § 4.7–4.9; Stakeholder Comment Nos. 22, 23, 24, 25, 27, 28, 29*
8. **Cost Recovery & EDC Ownership**: *Straw Proposal § 3.8, Section 5; Stakeholder Comment Nos. 21, 30*
9. **Consumer Protection, Data & Equity**: *Straw Proposal § 6.1–6.5; Stakeholder Comment Nos. 31, 32, 33, 34, 35, 36, 37, 38*
10. **Marketing, Timeline & Process**: *Straw Proposal § 7.1–7.3, Section 8; Stakeholder Comment Nos. 39, 40, 41*

Following the topic outline above, this document summarizes and responds to stakeholder feedback, grouped by stakeholder category.

# 1. Program Foundation & Objectives

***Straw Proposal section(s):*** *Executive Summary, § 1.1–1.4, § 2.1*

**Summary of Comments:** Stakeholders supported a statewide VPP program that reduces peak demand, improves reliability, and lowers costs for ratepayers. Most of the stakeholders also supported the two-phase structure, in which the Interim Program builds on existing demand response ("DR"), energy efficiency ("EE"), and electric vehicle ("EV") programs and serves as a learning period for the long-term program. The utilities asked that experience from the Interim Program guide the long-term framework and that EDCs keep a central role in defining grid stress and calling events. Many commenters asked the Board to define grid stress conditions in advance using clear, objective criteria. Technology providers and trade associations stressed the need to move quickly, to measure technology neutrality by performance, and to include on-site generation and bidirectional EVs. Several commenters proposed new objectives, including emissions reduction, increased clean energy, wholesale-market readiness, locational capacity, and winter flexibility. Advocacy groups asked that technology neutrality apply only to clean resources, while NJNG, DCO, and Foley sought a role for gas-fired and other on-site generation. Rate Counsel generally supported the Interim Program as a limited test with

safeguards but asked the Board to first show a need and verified net savings for ratepayers, and it was extremely skeptical of the long-term framework.

**i. Utilities and Utilities Association**

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, RECO, and NJNG

ACE, JCP&L, NJUA, and PSE&G all supported the phased approach and agreed that the Interim Program should build on existing utility DR programs, pilots, and customer participation. JCP&L, however, questioned whether the proposed budget accounts for the cost of maintaining those existing programs, and suggested that the Board should clearly distinguish between maintaining existing peak demand reduction and achieving new reductions when setting targets and budgets. ACE, JCP&L, NJUA, PSE&G, and RECO all agreed that experience from the Interim Program should guide the design of the long-term program, with ACE describing the Interim Program as a bridge and learning period, and NJUA and PSE&G describing it as the primary way to learn which operational models and market structures work..

**Staff Response:** Staff acknowledges that the VPP Interim Program is designed to build upon the existing demand response programs, the EDCs will have to propose budgets that reflect that. Staff notes that the long term VPP tariff, which is already being worked on through the Grid Flex workgroup under the Grid Modernization Forum in Docket No. QO26030059 will provide additional pathways for participation. Staff also notes that the start date of the program outlined in the Order is October 1, 2027.

NJUA stated that the EDCs have already invested in DR, managed EV charging, and DER integration, which give VPPs a strong base. It listed five principles: (1) build the Interim Program on existing utility programs; (2) set clear performance, cost-to-achieve, and target-population expectations before program development; (3) keep the Interim Program flexible and data-driven; (4) coordinate with existing markets rather than compete with them; and (5) let operational experience guide the long-term framework. NJUA asked the Board to resolve several foundational issues before the EDCs prepare their filings. It stated that the interim objectives may internally conflict and lack appropriate analytical support, such as potential studies specific to each EDC. NJUA supported a resource-neutral, technology-inclusive design focused on measurable performance. On technical barriers, NJUA asked the Board to clarify how distribution-level

objectives, such as non-wires alternatives and local reliability, fit into an Interim Program whose main target is a statewide PJM coincident peak reduction, since the resources and hours that best reduce the PJM peak may not provide the most distribution value. NJUA also stated that no single technology provider offers seamless interoperability across all DER devices. It asked that the Interim Program not require universal connectivity or technical requirements beyond commercially available capabilities, and that utilities be allowed to use existing utility systems, customer-authorized third-party platforms, and other qualified data sources for measurement, verification, and operational visibility.

**Staff Response:** Staff thanks the commenter for the comment and notes that the EDC-administered VPP Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. The VPP Interim program will expand the demand response programs, build the market and lower peak demand while the Board stands up the long-term tariff. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff. The Order provides the guidelines for the program but provides flexibility for the EDCs to propose additional metrics with explanation. The Order details all the goals and expects the EDCs to craft programs to meet all of them. Although the Interim program sets its 3% peak reduction target around coincident peak reduction, this objective does not necessarily outweigh other objectives, such as reducing transmission and distribution costs. The Order also calls for a Midterm Report which will help establish best practices for future programs.

JCP&L based its comments on five principles: (1) build on existing customer participation, utility investments, and operational capabilities; (2) clearly separate existing and incremental impacts when setting targets, budgets, baselines, and evaluation, measurement, and verification (EM&V) requirements; (3) align performance expectations, baselines, and budgets through a common framework based on technical, economic, achievable, and programmatic potential; (4) complement, rather than reduce, participation in PJM markets; and (5) let operational experience guide the long-term framework. JCP&L asked the Board to set clear cost-effectiveness, baseline, and evaluation methods before the EDCs finalize their program designs.

**Staff Response:** Staff thanks commenter for the comment and notes that the EDC-run Interim Program is designed as a bridge from the

existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff. The Order provides the guidelines for the program but provides flexibility for the EDCs to propose additional metrics with explanation. Staff notes that the benefit-cost methodology is detailed in the order and its attachments, and that each EDC will propose its baseline methodology in its filing until the EM&V subgroup's metrics are approved.

PSE&G encouraged the Board to treat VPPs as one part of an "all-of-the-above" resource adequacy strategy. It stated that EE and EV programs are building blocks for VPP participation, noting that more than 30,000 EV drivers are enrolled in its EV charging program and more than 1,000 of them have joined its Grid Flex DR program.

**Staff Response:** Staff appreciates the comment and notes that the Order directs the EDCs to build the VPP Interim Programs on existing devices funded through, for example, DR, EE, and EV programs. Staff expects that enrolling more of these existing customers is one of the fastest ways to reach the peak demand reduction target.

ACE, PSE&G, and RECO all stated that the EDCs should have the central role in defining grid stress and calling events. ACE recommended a statewide, utility-validated method based on feeder loading, voltage, contingency analysis, and reliability indicators, along with PJM 5 Coincident Peaks ("5CP"), Peak Load Contribution ("PLC"), and Network Service Peak Load ("NSPL")forecasts. ACE also recommended device-level data for performance measurement and settlement, standardized baselines across the VPP, GSESP Phase 2, Triennium DR, and GridFlex programs, and a distribution-first dispatch hierarchy. PSE&G stated that EDCs should be allowed to propose their own grid stress definitions and coordinate with PJM on market-based drivers. RECO stated that EDCs must keep the authority to call events in both phases, including when they expect a system or local peak, as utilities do in New York.

**Staff Response:** Staff acknowledges the comments and notes that, under the Order, dispatch events are called during periods of high grid stress as determined by the EDC in coordination with PJM. Events are informed by a forecast of PJM's 5CP hours but may also be called for

distribution-level constraints and other qualifying grid stress conditions. Each EDC must define in its filing the conditions that qualify as a grid stress event and how it will decide in real time to call one. Under the PowerUp NJ Working Group's EM&V subgroup, it will recommend shared EM&V metrics and methodology, including the baselines, after the EDC proposed filing are approved by the Board.

ACE and RECO both recommended treating the Interim Program objectives as guiding principles for the long-term program, to be confirmed after Interim Program results are known. ACE stated that applying the objectives to the long-term tariff should depend on DERMS Tier 2 capability, approved PSUP filings, final GridFlex service definitions, AMI data access standards, and the 12-month Interim Program evaluation. RECO asked for enough time between the two phases to assess results and make changes.

**Staff Response:** Staff recognizes the role of the VPP Interim Programs' results in shaping the long-term VPP framework and notes that the Order provides for a Midterm Review of the first twelve (12) months of each EDC's VPP Interim Program, after which the Board will determine whether the program should be continued, modified, expanded, or phased out in favor of the long-term framework. Over the same period, the EDCs are expected to work with Staff on the Proactive System Upgrade Plan (PSUP) proceedings, a GridFlex-based compensation tariff, and DERMS planning.

RECO supported many of the Interim Program objectives. On Objective "iv", it stated that much of the customer education the objective contemplates already occurs through existing programs. RECO also stated that a single, technology-agnostic program structure could limit the ability to address the different characteristics, customer value, and market maturity of each DER technology.

**Staff Response:** Staff thanks commenter for the comment and notes that the Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services. The Straw Proposal also calls for hardware incentives to remain in their existing EE and EV programs, the VPP Interim Program structure provides a way to compensate those devices for their service to the grid. EDCs have the ability to propose programs that offer different values for different devices.

NJNG supported deploying DERs to address supply gaps and grid constraints while meeting the State's emissions, reliability, and affordability

goals. It recommended a technology-inclusive framework that uses the existing gas distribution system and customer-owned equipment, such as fuel cells, linear generators, microturbines, combined heat and power (CHP), hybrid heating, and natural gas backup generators, to provide firm, dispatchable power. NJNG also recommended evaluating duration, dispatch certainty, operational continuity, customer experience, participation, and satisfaction, in addition to peak reduction and cost-effectiveness. NJNG cited other jurisdictions that include customer-sited natural gas backup generation in grid-support programs, including California's Demand Side Grid Support Program and Emergency Load Reduction Program and DTE Energy's residential home generator pilot in Michigan. It cited these examples as support for a flexible, performance-based framework that does not decide at the outset that only one class of resource can provide VPP value.

**Staff Response:** Staff thanks commenter for the comment. The technology-neutral framework envisioned in the Straw Proposal was designed as a clean energy, technology-neutral program.

**ii. Division of Rate Counsel**

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel stated that the threshold question is whether, where, and how much additional VPP capacity is needed and cost-effective for ratepayers. It did not oppose customer-sited resources, DR, storage, or managed charging, but asked the Board to identify the system need, the loads causing it, and whether VPPs cost less than reasonable alternatives. Rate Counsel also stated that the Straw Proposal's summary of the June 16, 2026 roundtable did not capture its position that, under cost causation, ordinary ratepayers should not pay for VPP programs.

**Staff Response:** Staff notes that the Order provides details on the benefit-cost analysis indicating a benefit-to-cost ratio (BCR) of 1.16 across the state, indicating that the program will provide benefits to all ratepayers. This BCR is based on the RIM cost test, which focuses on financial costs and benefits rather than the additional emissions and societal benefits. Staff also notes that the VPP Interim Program is designed to build upon existing DR programs to quantify the savings that VPPs can produce on the distribution, transmission, and capacity level. Staff also notes that the proposed program does not fund devices themselves, but rather provides compensation for providing a benefit to the grid by curtailing energy use during specific events.

Rate Counsel identified three main gaps: no New Jersey-specific method to project and verify net savings; no evaluation of VPPs against existing ratepayer-funded DER, DR, rate design, efficiency, grid, and bulk-power programs; and no test of whether total compensation from all sources exceeds the value delivered. It asked the Board to close these gaps before approving binding budgets, targets, long-term compensation, or enabling investments.

**Staff Response:** Staff acknowledges the concerns and notes that the Order and attachments includes several provisions that address them: common benefit and cost line items so the four EDC filings are computed on the same basis; verification of savings by an independent evaluator retained by the Board; a requirement that each EDC identify existing incentives and separate embedded from incremental costs; safeguards against double compensation across NEM, Block 1, Triennium programs, and PJM markets. The budgets in the Order intend to serve as guidance, and each EDC's proposed budget, targets, benefit-cost results, and justifications will be subject to Board review in its petition.

Rate Counsel conditionally supported the two-year Interim Program as a transitional means of testing VPP concepts using existing utility, aggregator, AMI, and demand-response capabilities and enrolled customers, while reserving judgment on individual program designs, budgets, compensation mechanisms, and performance targets until the EDCs submit their MFR filings. It questioned whether the three-percent peak-reduction target could reasonably be achieved by July 1, 2027, under the proposed schedule and recommended accountability measures once the Board establishes the need for and cost-effectiveness of the target. Rate Counsel supported collecting operational data comparing local distribution needs with broader system events and DER availability; facilitating customer education and market development; testing communications, performance-measurement, and reporting standards across the EDCs; establishing competitive EDC-aggregator contracting; prioritizing pay-for-performance compensation while minimizing fixed enrollment payments; and quantifying retail peak-load reductions and distribution-level grid-service values. It recommended using the Ratepayer Impact Measure ("RIM") as the primary cost-effectiveness test and including all associated costs, including distribution upgrades, interconnection, and the original costs of implementing AMI. Although Rate Counsel recommended carrying these measurement and cost-effectiveness objectives into any long-term program, it stated that the Interim Program should not create an entitlement to future budgets, tariffs,

or compensation and expressed skepticism regarding unresolved cost-allocation, cost-effectiveness, and ratepayer-savings issues in the long-term framework.

**Staff Response:** Staff appreciates the comments and notes that the Order treats the VPP Interim Programs as transitional. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out, and long-term compensation will be addressed in a separate tariff proceeding. The Order has multiple reporting requirements, including performance-based EDC-aggregator contracts, separate reporting of load reduction during 5CP hours, annual submission of a peak shaving adjustment (PSA) plan to PJM, definition of grid stress events, and use of the RIM as the primary cost test to access the cost-effectiveness of the program.

**iii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, Edge Zero, EnergyHub, ev.energy, Foley, Honeywell, Koolbridge, Logical Buildings, Lunar, ModernElectric, Nexamp, Oracle, Piclo, Recurve, Renew Home, RExChain, Solar Landscape, Steffes, SunStrong, Tesla, Tri-State, Turtle & Hughes, Uplight, UtilityAPI, Voltus, and WeaveGrid

EnergyHub, ev.energy, Renew Home, Solar Landscape, SunStrong, Tesla, and Uplight all expressed general support for the Interim Program objectives. Honeywell, Koolbridge, Logical Buildings, Piclo, and WeaveGrid all supported the two-phase structure. EnergyHub added that VPP eligibility should not be tied to PJM requirements or FERC Order No. 2222, noting that ConnectedSolutions in New England has delivered wholesale value without it.

**Staff Response:** Staff thanks the commenters for the comments and notes that the two-phase structure is supported in the Order. Requirements that align with PJM or FERC Order No. 2222 are intended to open additional stackable revenue streams in the future, with strong anti-double-counting provisions. A VPP provider under the Order does not need to be registered with PJM to participate.

Calibrant, DCO, ev.energy, Honeywell, Koolbridge, Logical Buildings, ModernElectric, Nexamp, Steffes, and Uplight all supported a technology-neutral program. Steffes and Koolbridge both recommended defining eligibility by measured performance rather than by device type. Steffes

proposed a common performance screen based on verified peak reduction, dispatchability, duration, telemetry, persistence, interoperability, customer protection, and cost-effectiveness. Koolbridge recommended measuring performance at the revenue meter. DCO stated that neutrality must work in practice and asked the Board to recognize microgrids that combine CHP, solar, and storage as eligible resources. Calibrant cited the technology-neutral goal in asking Staff to confirm that behind-the-meter (BTM) batteries are eligible in both phases whether the host facility connects at the distribution or transmission level.

**Staff Response:** Staff thanks the commenters for the comments, and notes that device flexibility and interoperability are embedded in the design of the program and that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

Uplight and ev.energy both asked the Board to define grid stress conditions with consistent, objective criteria so aggregators can plan dispatch in advance. Uplight also requested that these definitions distinguish between enrolled, available, committed, dispatched, and delivered capacity. Uplight recommended designing the framework around lowering the total cost of serving New Jersey customers. It also recommended defining the peak reduction objective in advance and, for Phase 1, measuring the percentage peak-demand reduction against PJM's actual 5CP hours. For distribution-level needs, Uplight recommended testing VPP performance without imposing a separate percentage or MW reduction target and instead establishing a target for the number and diversity of distribution areas or constraints addressed. It recommended that EDCs identify qualifying thermal constraints, local congestion, and other grid-stress conditions in advance where practicable and report the capacity available, dispatched, and delivered during each event and whether the response successfully addressed the identified need. Uplight also recommended accounting for customer opt-outs, device constraints, and EDC overrides when measuring performance and making demonstrable net ratepayer benefits a core program requirement rather than merely an evaluation item. ev.energy recommended building on the customer trust established in existing programs and adding a wholesale-market-readiness objective to the long-term program so PJM-compatible data is collected from the start.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order requires the EDCs to define grid stress events and contains specific dispatch requirements.

DCO supported a durable, performance-based framework that lowers capacity and infrastructure costs, improves reliability, and pays DERs for verified grid services. It stated that CHP should count as net demand reduction even without export, and recommended an Interim Program demonstration pathway for commercial, industrial, and institutional CHP microgrids.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

Edge Zero took no position on compensation or market structure but supported a phased, data-driven design. It stated that the long-term framework depends on distribution visibility that EDCs are not required to develop. Edge Zero stated that real-time, transformer-level monitoring would help utilities use more hosting capacity, find constrained circuits faster, defer capital spending, and improve dispatch data.

**Staff Response:** Staff thanks the commenters for the comment.

Foley recommended expanding eligibility to existing non-residential, BTM on-site generation, such as standby, prime power, and CHP units at hospitals, factories, cold storage facilities, and data centers. It stated that these resources provide firm, dispatchable capacity during severe weather, grid stress, and outages, when residential devices may not be available.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw Proposal indicates that the VPP Interim Program is the first step in building out a robust market for storage and grid services.

Honeywell recommended starting with a limited set of verified services: peak demand reduction, critical-hour response, and resource availability. It recommended readiness-based stage gates rather than fixed dates for program launch and expansion. Honeywell also asked the Board to preserve EDC authority over distribution operations, operating limits, and official records, while allowing qualified aggregators and providers to perform defined functions under clear controls.

**Staff Response:** Staff thanks the commenters for the comment and notes that many of these requirements and metrics are contained in the Order.

Koolbridge supported the Straw Proposal's cost-effectiveness grounding. It asked the Board to direct the EDCs to include in their December 31, 2026 filings one comparative demonstration of about 50 to 100 homes. The demonstration would measure whole-home coordination through intelligent electrical panels against device-level control, with multiple technology providers and independent measurement and verification.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

Logical Buildings supported the Straw Proposal's focus on affordability and its move toward an open-access long-term market. It asked for practical provisions for homeowners, renters, and multifamily buildings, including portfolio-level enrollment. Logical Buildings recommended measuring success by verified grid value and customer outcomes.

**Staff Response:** Staff thanks the commenters for the comment.

Lunar stated that it plans to participate as an aggregator, DERMS provider, and battery manufacturer. It identified five areas that need refinement: (1) the Interim Program design and aggregator framework; (2) long-term compensation and EDC ownership; (3) coordination with GSESP Phase 2 and Triennium 3; (4) access for low- and moderate-income (LMI) customers; and (5) customer trust as an evaluation criterion.

**Staff Response:** Staff thanks the commenters for the comment and notes that the VPP Interim Program and Block 1 MFRs are attached to the Order, and work will continue through the Grid Modernization Forum proceeding *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)* to develop the long-term compensation.

ModernElectric supported an aggregator-open, technology-neutral program that produces measurable ratepayer savings. It recommended treating residential storage as a dispatchable, customer-authorized resource class that provides verified local capacity. ModernElectric also recommended adding an objective to turn customer-sited DERs into locational capacity that EDCs rely on in grid planning and settlement.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw Proposal indicates that the VPP Interim Program is just

the first step in building out a robust market for storage and grid services.

Oracle recommended preserving an explicit utility-administered pathway for DR, customer engagement, and behavioral demand response (BDR) in both the interim program and the long-term VPP framework, alongside competitive third-party aggregators. It stated that resources should qualify for the retail and distribution peak reduction they provide, even when that value is not tied to PJM compensation.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order outlines the role for EDCs in the Interim program.

Piclo supported Objectives iv and vi on building aggregator capacity and a competitive contracting framework but stated that these objectives would fail if the Interim Program's contracting framework is bespoke to each EDC. It asked the Board to read Objective v as a mandate for cross-EDC standardization and to add an explicit objective to generate operational evidence on open procurement mechanisms, citing Great Britain's experience. Piclo also recommended a shared, neutral flexibility marketplace across all four EDCs rather than allowing four incompatible EDC portals to emerge by default.

**Staff Response:** Staff thanks the commenters for the comment and notes that the VPP Interim Program is designed to build upon the EDC's demand response programs, bringing standardization where possible while the Grid Modernization Forum *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)* designs the compensation-based tariff. Staff also notes that the PowerUp NJ Working Group will also help establish consistency across programs.

Recurve stated that building the Interim Program on the existing Triennium DR, EE, and EV asset base is the fastest, lowest-cost path to scale. It recommended a phased, evidence-based approach to setting targets.

**Staff Response:** Staff thanks the commenters for the comment, and notes that the VPP Interim Program is designed to build upon the existing demand response programs.

Renew Home estimated more than 1.5 GW of untapped residential flexible capacity statewide. It recommended recognizing OEM-led and aggregator-led enrollment, noting that more than 200,000 New Jersey customers have enrolled in its Energy Shift program but have no approved pathway into

utility or PJM programs. Renew Home also recommended device-level enrollment and settlement using randomized controlled trials, with a sample of AMI data as a backstop check.

**Staff Response:** Staff thanks the commenters for the comment, the VPP Interim program is designed to build upon the existing demand response programs by providing a path to participation.

RExChain supported an open-access framework that includes independent aggregators from adjacent DER markets, such as solar and SREC management. It stated that these aggregators can build near-term enrollment and data connections and move customers toward dispatchable storage over time.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

Steffes supported a framework that procures measurable grid services without unnecessarily limiting the technologies that may provide them. It asked the Board to make winter flexibility an explicit objective, noting that PJM forecasts winter peak demand to grow faster (2.7% per year) than summer peak demand (2.4% per year).

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order includes winter events in the dispatch protocol.

SunStrong supported the core objectives and limited its comments to two design choices it viewed as affecting the viability reaching the 3% target by July 1, 2027. First, it recommended allowing opt-out enrollment where an aggregator already holds the customer's contractual authorization, noting that 81% of customers in Puerto Rico's Customer Battery Energy Sharing program enrolled through an opt-out pathway. Second, it recommended a minimum contract term with locked-in incentive values, noting that Massachusetts, Rhode Island, Connecticut, Maine, and Colorado provide multi-year incentive certainty.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order requires EDCs to provide a transition plan to a long-term tariff.

Tesla recommended pairing VPP programs with PSA plans, or similar load-forecast adjustments under PJM Manual 19, as the main way to capture

capacity value and lower zonal capacity obligations. Tesla stated that curtailment during a few potential 5CP hours has little effect on PJM's load forecast, while a PSA lowers zonal obligations about nine months after plan submission and can use Temperature-Humidity Index (THI) dispatch triggers. It asked that PSAs proceed in parallel so the Interim Program is not delayed.

> **Staff Response:** Staff notes that the Order requires each EDC to submit a PSA plan by September 10 of each year after, beginning in 2027.

Tri-State agreed that VPPs are a cost-effective alternative to traditional peaking plants. It stated that residential programs must combine all technologies, EE, financing, and demand-savings incentives, and that commercial customers will participate if there is a financial incentive.

> **Staff Response:** Staff thanks the commenter for the comment and notes that the Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

Turtle & Hughes supported a statewide VPP program as essential to long-term affordability, reliability, and grid modernization. It viewed the move from traditional DR to a competitive DER marketplace as a practical way to improve grid performance and create new opportunities for customers to manage energy.

> **Staff Response:** Staff thanks the commenter for the comment and notes that the Order reflects the evolution from traditional DR to a more robust grid service compensation.

UtilityAPI supported the Straw Proposal, stating that VPPs provide fast, cost-effective grid flexibility as PJM capacity costs rise. It stated that streamlined electronic access to customer interval and account data is essential to both the Interim and long-term programs.

> **Staff Response:** Staff thanks the commenter for the comment.

Voltus stated that the Straw Proposal reflects substantial progress, especially on data access. It asked the Board to take a more ambitious approach on the dispatch trigger, peak reduction targets, and the Triennium 2 grandfather clause, and to make sure the program creates grid services beyond those already available through PJM.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The Order includes dispatch requirements and peak shave targets.

WeaveGrid viewed the two phases as a step toward a bottom-up, grid-aware framework. It recommended using the Interim Program to collect detailed performance, distribution-system, and cost data.WeaveGrid also asked the Board to preserve EDC flexibility to test designs suited to each service territory and to avoid service gaps for enrolled customers. WeaveGrid emphasized grid-aware Edge DERMS capabilities and diverse DER portfolios, including active managed EV charging as a foundational near-term resource. It recommended retaining AMI as an important measurement, verification, settlement, and data-access component of the VPP framework while accepting validated device-level telemetry as a complementary pathway. It further recommended that benefit-cost analyses account for the time- and location-dependent value of DERs, including avoided or deferred distribution investments.

**Staff Response:** Staff thanks the commenters for the comment and notes the Order includes a variety of metrics and reporting to help determine best practices for future programs.

**iv. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, Mission:data, NJCCC, SEIA/CCSA/NJSEC, Smart Thermostat Coalition, and VGIC

Advanced Energy United and the BTM Coalition urged the Board to ensure that the program begins delivering results in 2027, while ChargEVC called for expeditious implementation without recommending a specific launch date. Advanced Energy United stated that the program should have a meaningful impact on ratepayer bills beginning in summer 2027 and recommended viable commercial and technical participation pathways for all key DER types currently deployed on the grid. The BTM Coalition recommended a single event-based, pay-for-performance program for all BTM storage, modeled on ConnectedSolutions, that is operating by July 1, 2027 and designed to fold into the long-term program. ChargEVC recommended starting with simple, easy-to-explain, efficient-to-implement designs and not letting “the perfect be the enemy of the good”.

**Staff Response:** Staff notes that meaningful ratepayer impacts require PJM to reflect the savings in its load forecast, which requires the EDCs

to submit PSA plans, which is a requirement of this Order. Participants will see savings in the form of payments for participation when EDCs begin calling events. Additional savings will come from properly reported PSA plans and as EDCs begin to quantify the savings realized at the distribution, transmission and capacity levels as part of the EM&V process through the PowerUp NJ Working Group.

SEIA/CCSA/NJSEC and Advanced Energy United both recommended defining grid stress conditions in advance. SEIA/CCSA/NJSEC recommended using PJM peak-risk forecasts, EDC system constraints, emergencies, or other documented triggers. It further recommended that performance be measured by device-level telemetry or, where that is not available, a Board-approved baseline and interval data, followed by timely settlement. Advanced Energy United recommended including weather-driven, reliability-triggered dispatch rather than relying only on 5CP hours. SEIA/CCSA/NJSEC also supported goals that produce measurable peak reductions, lower capacity and transmission costs, and improve reliability, and recommended carrying the same goals into the long-term program. It commended Staff for drafting the Straw Proposal in just over four months.

**Staff Response:** Staff thanks the commenters for the comment and notes that the VPP Interim Program is referenced as an interim step to gather learnings, build customer understanding of VPP programs, and achieve ratepayer savings. Staff also notes that the Order requires the EDCs to define their grid stress events.

The BTM Coalition supported a range of technologies but stated that technology neutrality does not mean every technology must follow the same program mechanics. It stated that storage operates differently from traditional DR and suggested its own participation pathway. BTM Coalition also recommended that wholesale market participation should not be a requirement.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order includes differing metrics for the VPP Interim Program and Block 1.

Advanced Energy United recommended that the Board define a third-party-supplier pathway to implement the Executive Order's contemplated supplier role. It observed that the Interim Program's service-delivery pathways, long-term open-access tariff, and licensing framework are structured exclusively around DER aggregators. Advanced Energy United proposed defining "third-party supplier" separately from "aggregator";

recognizing existing Board-issued supplier licenses; providing equal treatment for supplier-enrolled load; applying disclosure-based consumer protections instead of the 70-percent pass-through requirement, which presumes a program payment that suppliers do not make; and evaluating double counting by the service compensated rather than the channel through which a resource participates.

**Staff Response:** Staff thanks the commenters for the comment. Under the Order, a VPP provider is defined by the function it performs rather than by entity type, so a third-party supplier that aggregates and dispatches customer DERs may participate as a VPP provider. Staff also notes that the Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

EEA-NJ supported having customers who enroll after approval of the VPP Programs enter directly under the VPP framework. It also supported migrating existing Triennium demand-response and VPP pilot programs into the VPP Interim Program to preserve program continuity and avoid redundant enrollment and administrative processes.

**Staff Response:** Staff thanks the commenters for the comment. The Order requires the EDCs to provide a transition plan for existing Triennium demand response customers and notes that when the VPP Interim Program opens it will become the EDC's demand response program option.

Mission:data supported the objective of non-discriminatory, timely, and automated customer data access through application programming interfaces (APIs). It stated that this access is needed to manage hundreds of thousands of residential participants.

**Staff Response:** Staff thanks the commenters for the comment.

NJCCC stated that front-of-the-meter, distribution-connected (FTM-D) battery storage is essential to meeting the State's goal of 2 GW of storage by 2030, Executive Orders No. 1 and 2, and peak-shaving targets. It expressed concern that the Straw Proposal largely omits FTM-D storage. NJCCC also supported the comments of the Associations for Clean Technology (SEIA, Advanced Energy United, and CCSA).

**Staff Response:** Staff recognizes that front-of-the-meter storage can play a significant role in building a more flexible grid and notes that the

Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

The Smart Thermostat Coalition supported the Straw Proposal's technology neutrality, its near-term reliance on installed residential devices, and its path toward a long-term market. It recommended that the main objective of the Interim Program be keeping the existing enrolled base from the Triennium programs without re-enrollment, while also accommodating newer OEM-led participation models.

**Staff Response:** Staff acknowledges the comment and notes that the Order directs the EDCs to use their existing DR programs and enrolled customer bases as the foundation of the VPP Interim Programs. Existing Triennium aggregator and OEM relationships may continue without a new solicitation, and each EDC must describe in its filing how those relationships will transition.

VGIC commended the Board for using customer-owned DERs, including thermostats, batteries, EV chargers, and bidirectional chargers, to provide grid services. It identified EVs as the largest long-term source of flexible demand and urged full integration of bidirectional EV charging into the Interim Program (2027–2029) to meet Executive Order No. 2 goals and lower customer bills.

**Staff Response:** Staff views V2G technology as a form of storage that should be compensated as such as part of the long-term tariff contemplated in the Straw Proposal.

**v. Advocacy Groups**

Commenter(s) Referenced in This Summary: ACEEE, Ceres, CJNJ, Evergreen Action and EDF, NEEP, New Jersey LCV, NJECN, NJEJA, Sierra Club, and Vote Solar

Ceres and New Jersey LCV both supported a statewide VPP program as a way to lower costs, improve reliability, and reduce reliance on fossil-fueled power plants. Ceres stated that VPPs are a fast, scalable alternative to central generation that can also make New Jersey more competitive for data centers, manufacturing, and logistics. It urged clear policy direction and a phased rollout that starts with pilots and scales over time. New Jersey LCV recommended establishing measurable statewide peak-demand-reduction targets for 2030 and 2035 to provide accountability, track progress, and ensure that the program develops at a scale capable of

addressing growing loads, reducing peak demand, and deferring transmission and distribution investments.

**Staff Response:** Staff thanks the commenters for the comment.

Evergreen Action and EDF, NJECN, and Sierra Club all asked the Board to keep fossil-fueled generation out of the program. Evergreen Action and EDF recommended limiting technology neutrality to zero-emission and non-emitting resources. NJECN recommended excluding any DER whose power source does not meet New Jersey's Renewable Portfolio Standard (RPS), such as gas, diesel, or gasoline backup generators. NJECN and Sierra Club both asked the Board to make increasing clean energy a stated objective of the program. Sierra Club also urged the Board to finalize a real long-term VPP program quickly.

**Staff Response:** Staff thanks the commenters for the comment and notes this the VPP Interim Program was designed as a Clean Energy, technology-neutral program.

Evergreen Action and EDF supported the two-phase structure with three changes: (1) set a firm outside date for the transition rather than relying only on milestones; (2) design the Interim Program for migration from the start; and (3) preserve customer continuity across phases. They supported all eight guiding principles and recommended a ninth on reducing greenhouse gas and criteria pollutant emissions, especially in overburdened communities. They recommended that each EDC publish objective criteria for grid stress conditions in its December 2026 filing and that performance data be independently verifiable. They also asked the Board to add objectives on distribution planning, non-monetary benefits, and customer experience; to treat coordination with related proceedings as a guiding principle; and to carry these objectives into the long-term program. Evergreen Action and EDF recommended evaluating VPPs on equal footing with traditional capital investments.

**Staff Response:** Staff thanks the commenters for their comments and notes that the milestones outlined in the Straw Proposal are important to developing a strong market and the Straw Proposal indicates when Staff anticipates each of these happening. Staff also notes that the Order calls for the EDCs to clearly describe the transition plan in their filings, both from the existing programs and from the VPP Interim Program to the long-term tariff that is stood up. The Order also directs Staff to evaluate, following the Midterm Review, a potential

performance incentive or shared-savings mechanism tied to verified savings.

ACEEE stated that the purpose of a VPP is to meet customer electricity needs while displacing more expensive traditional supply investments. It noted that the Interim Program allows New Jersey to move from basic connected DR (a Level 1 VPP) to enhanced DR (a Level 2 VPP) and to build the capabilities needed to displace peaker plants.

**Staff Response:** Staff thanks the commenter for the comments and notes that the VPP Interim Program will build upon existing DR programs.

CJNJ argued that a voluntary, market-driven, bring-your-own-device approach alone would not deploy DERs quickly or broadly enough to address New Jersey's affordability emergency and PJM capacity shortfall. It identified three shortcomings: customer-driven deployment may not place resources where they provide the greatest grid value; upfront costs may exclude LMI households, renters, and other high-energy-burden customers; and exclusive reliance on customer-owned resources may forgo opportunities to create an in-state union industry. CJNJ proposed a utility-led, union-built Networked Power Program based on four principles: faster fleet-scale deployment, strategic siting, utility-financed access and host benefits for underserved customers, and development of a skilled union workforce. The Board would allocate capacity targets among EDCs based on load share and review utility plans for cost-effectiveness and compliance with defined performance standards and timelines.

**Staff Response:** Staff recognizes that there are specific use cases where utility-owned and operated infrastructure, including storage, may be the quickest, most cost-effective method. The Board is currently looking at how to better define those use cases in future proceedings.

NEEP supported using existing DR programs in the Interim Program while planning for the long-term program. It recommended utility business model reforms, performance goals for the long-term program, and deployment of DERs in areas with grid constraints. NEEP recommended that the Board and utilities conduct a planning process to establish Long-Term VPP performance goals, using existing distribution-system planning forums such as the Grid Mod Forum and the Integrated Distribution and DER System Planning ("IDDER") workgroup.

**Staff Response:** Staff thanks the commenters for the comment and notes that this is reflected in the Order and the Straw Proposal.

NJEJA asked the Board to build environmental justice safeguards into every part of the program. It proposed a "Three-Pillar Energy Justice Framework": (1) a Community DER Overlay; (2) performance-based regulation with equity metrics; and (3) binding community governance through a Community Advisory Board. NJEJA stated that this framework would make the program a public asset that builds community wealth.

**Staff Response:** As the Straw Proposal notes, there are many moving parts to developing a strong VPP program and a market that relies on compensation for the value DERs bring to the grid. Providing opportunities for LMI families to participate and encouraging equity-based programs will be part of the long-term vision of the VPP. The VPP Interim Program relies heavily on existing devices participating as grid services. For the VPP Interim Program, each EDC must describe how its program will reduce barriers to participation for LMI customers and customers in overburdened communities and must report participation by these customers.

Vote Solar expressed concern that the Interim Program largely repackages existing Triennium DR programs without clear open-access pathways for non-Triennium devices, battery storage, or front-of-the-meter (FOM) resources. It recommended a bring-your-own-device (BYOD), pay-for-performance structure similar to the ConnectedSolutions program, with GSESP in a complementary role providing upfront incentives, tailored compensation for FOM, and specialized storage projects not captured by a ConnectedSolutions-like VPP. Its proposed near-term objectives were a BYOD roadmap, near-term FOM compensation, a community storage and community solar-plus-storage rulemaking, and an immediate avoided cost and value of storage study.

**Staff Response:** Staff thanks the commenter's comment and views the proposed VPP Interim Program as a bring-your-own-device program. Staff acknowledges that the VPP Interim Program is designed to build upon the existing demand response programs but notes that the long term VPP tariff, which is already being worked on through the Grid Flex Workgroup will provide additional pathways for participation. However, the Interim program can provide opportunities for savings and encourage market development while the tariff is stood up.

**vi. Program Implementers and Administrators**

Commenter(s) Referenced in This Summary: Ampion, Energy Solutions, MaGrann, Michaels Energy, and Power TakeOff

Ampion proposed that the Interim VPP framework include a "VPP Settlement Administrator" (VSA), a defined, licensed role responsible for settlement, measurement, reconciliation, and verification. It argued that the Straw Proposal describes these functions but does not assign them to an independent party, leaving them to fall to EDCs. Ampion contends that this arrangement is in tension with the aim of neutrality. Ampion recommended defining the VSA in § 1.2, licensing VSAs under a framework modeled on DER aggregator licensing, and using a single Board-approved settlement method for all VSAs to promote competition on cost and service. It further suggested that EDC systems and the DER Registry should be required to interoperate with any licensed VSA.

> **Staff Response:** Staff thanks the commenter for the comment and notes that licensing was included in the Straw.

Energy Solutions supported the phased approach, the July 1, 2027 milestone, and the technology-neutral design. It recommended building from existing DR, EE, and flexible load programs rather than creating a separate VPP structure from scratch, and emphasized coordination between existing programs. For the long-term framework, Energy Solutions supported preserving participation pathways for both aggregators and utility-administered participation models.

> **Staff Response:** Staff thanks the commenters for the comment notes that the EDC run Interim Program is designed as a bridge from the existing small demand response programs to a long term open market compensation based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff.

MaGrann encouraged program guidelines that support multifamily participation and reduce barriers to DER adoption in multifamily housing.

> **Staff Response:** Staff thanks the commenters for the comment.

Michaels Energy generally supported the Interim Program objectives and recommended adding four minimum filing requirement (MFR) objectives: (1) resource diversity, including commercial and industrial (C&I) demand flexibility such as thermal storage, controlled refrigeration, building controls, and industrial process loads; (2) engineering readiness, including screening, feasibility, baselines, controls integration, commissioning, and

post-event troubleshooting; (3) performance validation, including measured kW, response time, duration, availability, recovery, and net energy; and (4) early technology qualification. It stated that the long-term program must stay open to new hardware and controls that provide cost-effective grid services.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order and the MFR touch on these elements. The VPP Interim Programs intend to open to diverse DER types that can deliver grid value such as dispatchable demand response or load control. Each EDC must describe its enabling infrastructure, standards, and baseline methodology. Each EDC must also report verified load reduction, event response rates, and other relevant reports to the board and the public as described in the Order and the MFR. New devices may join over the program period, and the long-term framework is planned to be technology neutral.

Power TakeOff supported a market-based VPP to improve reliability and affordability. It stated that EE provides persistent, passive demand reduction and should serve as the foundation of any VPP.

**Staff Response:** Staff thanks the commenters for the comment and they reflect the language in the Straw and Order

**vii. Third-Party Suppliers**

Commenter(s) Referenced in This Summary: Base Power and NRG

NRG supported the proposed objectives of reducing peak demand, improving reliability, lowering customer costs, and enabling customer participation in DER programs. It recommended making customer participation the primary objective, relying on competitive markets to drive results, applying uniform statewide rules, and using the Interim Program as a bridge to a durable long-term market.

**Staff Response:** Staff thanks the commenters for the comment. Staff acknowledges that participation should be simple and attractive. The Order's objectives also include peak shaving, enabling customer familiarization and trust-building with VPP participation, creating an enrolled customer base from which the long-term, aggregator-led market can grow.

Base Power stated that Executive Order No. 2 calls for VPPs administered by both EDCs and third-party suppliers and recommended that the Board

set up an explicit third-party supplier pathway. It recommended aligning the program with Data Center Fair Share Act obligations, including Peak Shaving Adjustment Plans ("PSAs") and recognition of negative peak load contributions ("PLCs"). Base Power stated that third-party supplier VPPs can scale quickly and reduce peaks without tariff payments if billing systems allow negative PLCs.

**Staff Response:** Staff thanks the commenter for the comment. Under the Order, a VPP provider is defined by the action it performs rather than by the type of entity performing it, and third-party electricity suppliers are among the entities that may qualify. An EDC shall not restrict participation to a single type of VPP provider or limit the number of VPP providers that may participate. Each EDC must also file its PSA plan with PJM by the earlier of September 10 of each year or PJM's deadline, starting in 2027. However, there is currently no method by which the zonal load reductions provided by BTM storage exports can be captured in a PSA plan. Consistent with the policy goal of fostering more market-based VPP frameworks for retail customers, the Order directs each EDC to develop a plan to revise its PLC calculation and reporting methods to account for negative PLCs, and to file a summary of that plan with the Board by February 12, 2027. Each summary must describe any technical or legal issues the change might raise and how those issues could be solved. This change could enable business models in which third-party suppliers offer their retail customers rate reductions or other financial benefits in exchange for installing and operating BTM storage to reduce peak load, outside of an EDC-managed structure such as Block 1.

### viii. Government Agencies

Commenter(s) Referenced in This Summary: SMRSA

SMRSA supported efforts to improve reliability and maximize DER value through dispatchable renewable generation. It stated that wastewater treatment plants are critical public infrastructure that operate around the clock, and that their public health and resilience benefits should be recognized in program design and evaluation SMRSA asked the Board to examine demand-response baseline methodologies that could disadvantage facilities that had already invested in continuously operating distributed generation by reducing their recognized event-based response. It also recommended coordinating VPP policy with New Jersey's food-

waste diversion, methane-reduction, renewable-energy, and resilience objectives.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

**ix. Financial Services**

Commenter(s) Referenced in This Summary: Syntropic

Syntropic stated that its recommendations are intended to ensure broad, equitable adoption of the VPP and to avoid a regressive wealth transfer from lower- and middle-income households to wealthier households. It identified upfront capital as the main barrier for LMI customers and called for regulated third-party financing to broaden access while ensuring consumer protection.

**Staff Response:** Staff thanks the commenter for the comment and notes that the VPP Interim Program compensates grid services from devices customers already own and does not fund hardware. The Order identifies equity and LMI access as a market support structure.

**x. Individuals and Academic Institutions**

Commenter(s) Referenced in This Summary: Bill Beren, Cammie Croft, Digital Verity, Michael Winka, Peak+, and UDelaware

Bill Beren stated that the interim program appears focused on aggregators and asked the Board to recognize that individual homeowners can contribute directly as DERs. He emphasized that this could be done through solar and energy conservation technologies, but noted that current limits on residential solar would need to be addressed, such as by removing solar size caps tied to peak demand and creating tariffs that combine solar, heat pumps, and EVs. He also urged funding for NJ Transit solar and depot upgrades, reviving prior Orders requiring the installation of solar panels on utility poles and in parking-lots, and addressing Board rulemaking delays to meet proposed deadlines.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. Staff agrees that individual homeowners can contribute **]** as DERs, but acknowledges that interfacing through an aggregator, as opposed to

each homeowner interfacing with their EDC individually, can be a more accessible way to participate in a VPP. The respective limits on residential solar size are out of the scope of this Order**.**

Cammie Croft commended the Board and Staff for the depth and care of the Straw Proposal, which include market design, consumer protection, and equity provisions. The commenter recommended a "Community Benefit Virtual Power Plant" model, under the working name Common Current, that installs residential batteries with no upfront cost, debt, or clawback risk for the household, to reach low-income and energy-burdened families. Cammie Croft further stated that under the model, a mission-based owner-operator would aggregate the residential battery fleet into PJM markets and return the resulting value to participating households and communities.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

Michael Winka supported the eight guiding principles, especially ratepayer savings. The commenter recommended linking the long-term program to a new utility business model, specifically a utility-managed Distribution Service Operator (DSO) that procures local grid services, rather than limiting the long-term design to PJM markets under FERC Order No. 2222. Michael Winka also stated that limiting the Interim Program to peak reduction misses a chance for market transformation. The commenter recommended that the MFRs direct each EDC to test compensation for a separate grid service through a small sandbox pilot of a few thousand customers.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

Digital Verity supported building the Interim Program on customer-owned devices, such as thermostats, water heaters, EV chargers, solar, and storage, for speed and affordability. It recommended funding an independent, university-hosted threat modeling study during system design to assess the combined cyber risk across these private devices. It further requested that such a study's findings be made available to the VPP Implementation Working Group to aid in development of technical rules.

**Staff Response:** Staff thanks the commenter for the comment. The PowerUp NJ Working Group will evaluate how best to address the program's ongoing evaluation needs, including what studies would be most appropriate.

Peak+ stated that VPPs must serve as a bridge to reduce extreme loading caused by weather, data center growth, and industrial demand.

**Staff Response:** Staff thanks the commenters for the comment and notes that EDCs have the ability to define grid stress events in their filings

UDelaware stated that controlling battery storage, including controlled charging of battery and EVs , provides about ten times the grid value of simple load control. It noted that dual-use BTM storage costs less than 20% as much as purpose-built batteries. UDelaware recommended early sandbox demonstrations of EVs providing market grid services. As a separate point, it stated that sandboxes managing EVs are more likely to succeed if run by a VPP that already has experience controlling bidirectional EVs and qualifying them for EDC and PJM service markets.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. Staff views V2G technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw proposal.

## 2. Eligibility & Enabling Technology

***Straw Proposal section(s):*** *§ 2.2, § 2.3, § 4.6*

**Summary of Comments:** Most commenters supported technology-neutral eligibility based on measured performance. Many asked for clear pathways for battery storage, including exporting BTM batteries, C&I storage, and FOM storage, and for managed and bidirectional EV charging. Commenters differed on the minimum aggregation size. Several technology providers, trade associations, and advocates supported the 10 kW Interim threshold or no threshold at all, while Rate Counsel recommended 100 kW. Commenters also differed on whether to measure the threshold by enrolled or deliverable capacity, and on separate residential and C&I thresholds. Most supported the proposed communication standards but opposed requiring them at the device level, favoring the aggregator or cloud level. Many asked the Board to accept device-level telemetry alongside AMI data, to

resolve the 24-hour versus 48-hour data timing, and to require automated Green Button Connect data access.

**i. Utilities and Utilities Association**

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, RECO, and NJNG

ACE, NJNG, and NJUA all supported technology-neutral eligibility based on measured performance. ACE supported eligibility for any DER that can provide reliable, event-driven demand reduction, regardless of device class, vendor, platform, or ownership model. NJNG asked that customer-owned fuel cells, linear generators, microturbines, CHP, natural gas backup generators, hybrid heating, and waste heat to power be able to compete on the same performance criteria. NJUA stated that different DER types provide different value and that universal interoperability is not yet feasible. PSE&G asked that eligibility rules reflect differences in duration, response time, and telemetry, and that EDCs be allowed to propose new enabling hardware for LMI customers or new technologies.

**Staff Response:** Staff thanks the commenters for their comments and notes that the technology-neutral framework envisioned in the Straw Proposal was designed as a clean energy, technology-neutral program.

The utilities differed on the minimum aggregation size. PSE&G stated that no minimum is needed for the Interim Program, which focuses on territory-wide peak reduction, and that any long-term minimum should follow EDC analysis; it also asked the Board to define enrolled and deliverable capacity. ACE recommended measuring the 10 kW threshold as deliverable capacity, using AMI baselines and device-level data, with a separate 20 kW threshold for distribution services under the long-term tariff. It viewed 100 kW as a reasonable long-term starting point, subject to EDC-specific flexibility. RECO recommended basing the threshold on enrolled capacity, with deliverable performance verified through measurement and verification ("M&V"). ACE and RECO both stated that separate residential and C&I thresholds may be appropriate.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order retains a 10 kW minimum aggregation size per program event for the VPP Interim Program, which applies to the aggregation rather than to each device, while the 100 kW threshold remains contemplated for the long-term tariff.

ACE, PSE&G, and RECO all supported standards-based communication but opposed mandating specific protocols during the Interim Program. ACE supported requiring full compliance with OpenADR, IEEE 2030.5, and CTA-2045 only under the long-term tariff, with EDCs identifying supported protocols in their MFR filings. PSE&G recommended allowing functionally equivalent approaches, noting that residential DERs largely use proprietary APIs and that C&I standards still need work. RECO did not recommend any specific protocol for either phase yet, noting its use of DNP3 and ICCP for SCADA communication. JCP&L recommended deferring detailed telemetry, data-sharing, and DERMS requirements to later compliance filings or working groups, and scaling telemetry requirements to the value of the service.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order provides opportunities for flexibility if the EDC provides justification when proposing alternative parameters.

ACE, PSE&G, and RECO all stated that the AMI Data Access Standards will likely not be fully in place before the Interim Program ends. ACE stated that the Interim Program should not depend on them, noted that AMI alone cannot dispatch devices, and supported device-level telemetry through edge DERMS to supplement AMI, with recognition of limited integration costs. PSE&G stated that the utility meter and AMI system should remain the authoritative record for verification and settlement, and that any third-party data must meet EDC requirements.

**Staff Response:** Staff acknowledges the comments and notes that the VPP Interim Program does not depend on changes to the AMI data access rules. Performance is measured against a customer baseline using verified AMI interval data, and each EDC must propose its baseline methodology, including the treatment of accounts with on-site generation or storage. Each EDC must also describe its existing dispatch communication capabilities, including those of its DR program partners, and the EM&V subgroup of the PowerUp NJ Working Group will recommend shared EM&V metrics and methodology.

### ii. Division of Rate Counsel

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel stated that the 10 kW minimum aggregation size is too small and would raise overhead, noting that the 589 MW goal could mean up to 58,900 minimum-size aggregations. It recommended a 100 kW threshold

for both phases, no separate residential and C&I thresholds, and measurement based on capacity deliverable during an event. It also asked EDCs to separate nameplate, enrolled, committed, available, and verified deliverable capacity, and stated that non-coincident solar, batteries held for customer backup, and constrained resources should not be counted at full value.

**Staff Response:** Staff acknowledges the concerns. The Order retains a 10 kW minimum aggregation size per program event for the VPP Interim Program, which applies to the aggregation rather than to each device, consistent with the Interim Programs' reliance on existing customer devices such as smart thermostats, water heaters, and EV chargers. The 100 kW threshold remains contemplated for the long-term tariff. The Order and the MFR require each EDC to report enrolled devices, load under management, and verified load reduction as separate measures, and performance is measured against a customer baseline so that only delivered reduction is credited.

Rate Counsel supported encouraging the proposed communication standards in the straw, with exceptions for proprietary protocols that EDCs can adopt at little cost. It stated that ratepayers should expect AMI data access after paying for AMI, and that device or aggregator data can serve as a proxy where AMI data is unavailable. It opposed duplicative AMI or data-platform spending, asked EDCs to justify any new data function or meter upgrade, and asked the Board to resolve the 24-hour versus 48-hour settlement-data question on a technical record.

**Staff Response:** At this time, Staff expects that the EDCs to adhere to the Board's adopted requirements of the AMI data access rules and any subsequent Order establishing a process for Board staff to approve third parties as eligible to be authorized by customers to access AMI data. The AMI data access rules were adopted according to a rulemaking schedule initiated before this proceeding and represents a balance needed to prevent unnecessary investments and reflect uncertainty in energy market requirements for VPP programs at the time of drafting. Board staff continues to monitor the market and review if there is a need to propose an update to the rules. Staff will continue to assess actual operational and reporting requirements for VPP participation in wholesale markets and weigh the options to provide settlement data that reflect the most cost beneficial and technologically feasible means of doing so. The Interim program proposal does not contemplate that modification of the existing AMI data access framework is necessary for successful implementation and staff does

not presuppose that validated AMI data is necessary for successful implementation of the long-term program.

**iii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, Electrify America, EnergyHub, ev.energy, Foley, Honeywell, Koolbridge, Logical Buildings, Lunar, ModernElectric, Nexamp, NJRCEV, Oracle, PACE AI, Piclo, Recurve, Renew Home, RExChain, RIC Energy, Solar Landscape, Soltage, Steffes, Tesla, Tri-State, Turtle & Hughes, Uplight, UtilityAPI, Voltus, and WeaveGrid

Koolbridge, ModernElectric, Steffes, and Tri-State all asked that eligibility be broad and based on measured performance rather than device type. Koolbridge recommended defining eligibility by measured performance at the revenue meter. Steffes asked that electric thermal storage, standalone or paired with heat pumps, be expressly eligible and offered proposed rule language. Tri-State asked the Board to accept all viable solutions, including residential generators, mini-CHP, and mini fuel cells.

**Staff Response:** Staff thanks the commenters for the comment and notes that these are the path and criteria as outlined in the Straw and the Order. While this Order does not involve a formal APA rulemaking, Staff believes the eligibility criteria outlined in this Order is consistent with Steffes's proposed regulatory language.

Nexamp, NJRCEV, RIC Energy, Solar Landscape, and Soltage supported a pathway for FOM storage participation. Nexamp recommended allowing qualifying FOM resources to participate under clear, technology-neutral rules coordinated with GSESP Phase 2 to avoid conflicting requirements or duplicative compensation. It described FOM storage as a more standardized and scalable option than BTM storage for delivering locational grid services. Solar Landscape requested at least a limited FOM pathway during the Interim Program to generate representative operating and cost data. It further recommended issuing sufficiently detailed rules regarding future FOM eligibility, service and compensation architecture, and implementation timing early enough to support project development and financing, cautioning that the absence of FOM data from the Interim Program should not later be used to delay FOM eligibility. NJRCEV recommended prioritizing storage added to existing PJM wholesale solar sites with available interconnection capacity and evaluating eligibility based on the value provided by storage and firming technologies rather than

resource configuration alone. Soltage recommended avoiding an overly restrictive maximum threshold for large C&I systems and FOM assets connected to the distribution grid, citing their potential to provide T&D deferral and its experience with New York EDCs seeking distribution services from commercial-scale storage systems of up to 5 MW.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim Program is the first step in building out a robust market for storage and grid services. Staff also notes that the PowerUp NJ Program is limited to the behind-the-meter DERs, and FTM resources are currently not eligible for Block 1 resources, but that the Order does direct Staff to continue work on developing programs for other use cases, including FTM.

Calibrant, Electrify America, and Turtle & Hughes all supported BTM battery storage as an eligible resource. Calibrant asked Staff to confirm that BTM storage is eligible in both phases whether the host facility connects at the distribution or transmission level, and asked each EDC to define a C&I storage enrollment pathway in its MFR filing. Electrify America asked that thresholds not exclude storage at public charging sites. Turtle & Hughes indicated that the VPP program should encourage new batteries, intelligent controls, metering, and communications equipment, while ensuring that customers can evaluate the combined operational and economic benefits of those investments at customer sites.

**Staff Response:** Staff thanks the commenters for the comment and notes that BTM is included in the VPP Straw in both the Interim and long term which will allow for new technologies, controls and evaluation metrics to be evaluated.

Lunar, ModernElectric, Piclo, Recurve, and RExChain all supported the 10 kW Interim threshold, and ev.energy and Logical Buildings viewed the 10 kW and 100 kW thresholds as reasonable starting points. Honeywell, ev.energy, Lunar, ModernElectric, and Piclo all recommended measuring thresholds by capacity deliverable during an event rather than nameplate. Lunar asked the Board to codify the 10 kW and 20 kW thresholds in the MFR Order rather than leave them to each EDC and requested clarification on how the threshold is measured. ModernElectric, Piclo, and Logical Buildings stated that thresholds should apply to the aggregation, not to each device or premise. RExChain requested clarification that these thresholds may be met through aggregation across many individual small systems dispersed across a service territory. ev.energy suggested reconciling the 10 kW threshold with the 20 kW threshold and

recommended considering a threshold based on a percentage of feeder load. Honeywell recommended that thresholds be specific to each service pathway and that no wholesale minimum apply to resources providing only retail or distribution services.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order addresses these metrics in the MFRs. The Order sets a 10 kW minimum aggregation size per program event, which applies to the aggregation rather than to each device.

EnergyHub and Renew Home both recommended no minimum aggregation threshold, stating that thresholds have limited participation elsewhere. EnergyHub stated that each qualifying device should be able to enroll and be paid on its own performance. Renew Home recommended first seeing what enrolls in the Interim Program and, if a threshold is kept, using separate residential and C&I minimums measured at enrollment.

**Staff Response:** Staff thanks the commenters for the comment and notes that an individual customer can enroll in the Interim Program through the EDCs, their contracted aggregators, or their program administrators. Thresholds were designed to increase participation. Lack of guiding thresholds will create confusion for customers

Electrify America and Solar Landscape both stated that a single C&I site meeting the threshold should qualify without joining a multi-site aggregation. Electrify America also asked that the 100 kW long-term threshold track the FERC Order No. 2222 minimum and that the 20 kW distribution threshold be harmonized. Solar Landscape opposed thresholds based only on customer class and recommended that any separate C&I threshold not exceed 500 kW.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw Proposal only recommends a minimum aggregation size, not who must aggregate it. Staff notes that the long term tariff will be its own separate proceeding.

Foley recommended a separate size threshold for C&I on-site generation. It also asked the Board to direct the utilities to compile an inventory of existing BTM generation from interconnection records, cross-referenced with NJDEP permit data.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

EnergyHub, Renew Home, Tesla, and Uplight all opposed requiring specific communication protocols, noting that much of the market relies on secure proprietary OEM APIs. Tesla recommended relying on edge DERMS platforms to connect utility and device systems. Uplight recommended functional requirements, such as secure communications, telemetry availability, dispatch verification, customer consent, and M&V, while allowing proprietary integrations behind the utility-facing interface. EnergyHub recommended treating the standards as accepted pathways and allowing compliance to be shown through certification, third-party attestation, or vendor documentation.

> **Staff Response:** Staff thanks the commenters for the comment and notes that the Order establishes standards and provides opportunities for EDC input, especially through the PowerUp NJ Working Groups.

Honeywell, ev.energy, Koolbridge, Uplight, and Piclo supported the proposed interoperability standards as a baseline. Koolbridge asked the Board to require conformance and reject vendor-specific gateway requirements. For the Interim Program, Piclo recommended accepting any open-standard protocol currently supported by an EDC's platform, together with a published roadmap for convergence. For the long-term tariff, Piclo recommended mandating a single common dispatch-signal format across all four EDCs so that an FSP qualified in one territory would not need to re-engineer its integration for another. ev.energy recommended standards for each interface, including OCPP and ISO 15118 for EV charging, together with additional standards for bidirectional charging. Honeywell recommended staged compliance for existing devices. Uplight recommended that the Board avoid mandating a single protocol across every layer of the VPP architecture. Honeywell and Uplight asked EDCs to publish the protocols and interface requirements they support, while Turtle & Hughes recommended uniform communication protocols, interoperability requirements, equipment specifications, metering requirements, cybersecurity standards, and application processes across all four EDCs.

> **Staff Response:** Staff thanks the commenters for the comment and notes this is the process outlined in the Straw Proposal and the Order, which requires each EDC to accept devices using any communication protocol supported by its systems and to describe its roadmap for expanding protocol support.

Calibrant, EnergyHub, ev.energy, ModernElectric, Piclo, Renew Home, and WeaveGrid all asked the Board to accept device-level telemetry and/or

sub-metering for measuring performance. Calibrant recommended dedicated sub-metering for storage and asked how sub-minute services will be measured. EnergyHub supported AMI for C&I resources and device telemetry for residential BTM resources. Renew Home recommended randomized controlled trials using device telemetry, reviewed by an independent evaluator. Piclo recommended an accreditation and audit regime for approved measurement devices. WeaveGrid supported validated telemetry as a parallel option if the AMI Data Access Standards are not ready by completion of the VPP Interim Program. Calibrant and ev.energy both asked the Board to resolve the conflict between PJM's 24-hour settlement data and the 48-hour AMI validation timeline.

> **Staff Response:** Staff thanks the commenters for the comment and recognizes there are multiple technology paths. Each EDC proposes its baseline and measurement methodology in its filing, and the EM&V subgroup of the PowerUp NJ Working Group will recommend shared EM&V metrics and methodology.

Logical Buildings supported retaining utility AMI as the settlement backbone and audit reference while allowing validated complementary telemetry. Recurve recommended retaining AMI as the primary and required data source for baselining and M&V across all resource types, with supplemental device-level telemetry reported by aggregators or OEMs permitted for battery storage. Recurve stated that battery dispatch may occur at a resolution or on a timeline that AMI alone does not capture and recommended that supplemental battery telemetry be subject to specified minimum-resolution and reporting-latency requirements. Logical Buildings also recommended statewide service standards, including enrollment and unenrollment confirmation within five business days, validated event data within 48 hours, and a 24-hour pathway where required by PJM.

**Staff Response:** Staff thanks the commenters for the comment and notes this was contemplated in the Straw. The Order utilizes AMI settlement for the VPP Interim program.

UtilityAPI recommended that the Board direct EDCs to implement data-exchange platforms certified to the Green Button Connect standard. It identified three necessary platform functions: an objective third-party registration and approval process; customer authentication and authorization without requiring customers to share utility usernames or passwords; and availability of the interval-usage, rate-class, account, and other data needed for VPP and wholesale-market participation. Voltus

supported using New Jersey's AMI Data Access Standards as the VPP baseline but identified unresolved operational gaps involving third-party approvals, historical-data availability, and the optional use of Green Button Connect or Green Button Download. Voltus requested that the Board issue the implementing order under N.J.A.C. 14:5-10.6(b), establish objective approval criteria and a firm decision deadline—with 30 days offered as a reasonable benchmark—and coordinate that process with DER Aggregator licensing. It also requested at least 24 months of historical interval data and each customer's current Peak Load Contribution upon authorization and urged the Board to resolve the Green Button Connect-versus-Download issue because manual exports and differing EDC interfaces could impede enrollment and implementation.

**Staff Response:** The AMI Data Access rules were adopted according to a rulemaking schedule initiated before this proceeding and represents a balance needed to prevent unnecessary investments and reflect uncertainty in energy market requirements for VPP programs at the time of drafting. Staff continues to monitor the market and review if there is a need to update the rules. Staff also notes that the Green Button Data Standard is not the only available method for sharing customer data. The rules contemplate third party access to AMI Data through Electronic Data Interchange and access to flat files

WeaveGrid asked the Board to include active managed EV charging as a foundational Interim Program resource, including a Smart Charge Management-style offering at all four EDCs, and supported Edge DERMS platforms to coordinate customer-sited DERs, like EVs, batteries, and thermostats.

**Staff Response:** Staff thanks the commenters for the comment and notes this is one solution to address the MFRs through contracting with an Edge DERMS platform.

Oracle asked the Board to expressly include behavioral demand response and peak-time rebates as eligible VPP resources, noting that they reach renters, lower-income customers, and customers without compatible devices.

**Staff Response:** Staff thanks the commenters for the comment. The VPP is designed to compensate for services provided to the grid, and that the other programs may compliment this effort.

DCO asked the Board to list CHP, controllable customer-sited generation, and microgrids as eligible resources, and to allow resources that reduce net demand at the customer meter to qualify without exporting power. It offered proposed tariff language and cited the Middlesex College microgrid as an example.

**Staff Response:** Staff thanks the commenter for the comment and notes that the framework envisioned in the Straw Proposal was designed as a clean energy, technology-neutral program, and that the VPP Interim Program is the first step in building out a robust market for storage and grid services.

Lunar asked the Board to recognize meter socket adapters and other technologies that avoid costly electrical panel upgrades as eligible enabling technologies for LMI households, in both the Interim Program and GSESP Phase 2.

**Staff Response:** Staff thanks the commenters for the comment and notes the technology-neutral design will allow intelligent electrical panels participate as well as any new technologies that are brought to market as long as they meet the eligibility standards.

RExChain asked the Board to confirm a near- Interim Program role for solar-only portfolios, without treating them as dispatchable equivalents to storage, by recognizing behavioral and forecast-informed load shifting as an eligible use case, accepting portfolio-level solar production forecasting as an operational-data contribution, and accommodating a defined transition through which enrolled solar portfolios can add storage and become dispatchable over time.

**Staff Response:** Staff thanks the commenter for the comment and notes that, for now, customers with solar-only systems on a NEM tariff cannot include their solar systems in the VPP Interim Program, to avoid paying twice for the same value. These customers may still enroll other eligible devices, and each EDC proposes its eligible DER types in its filing. A solar customer may add storage can participate through Block 1, as set out in the Board Order and Block 1 MFR (Attachment B).

PACE AI stated that its AI-enabled HVAC retrofit controls are already incentivized under Triennium 2 and are suitable for VPP participation.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order contemplates a technology neutral program.

UtilityAPI cited a recent FERC order finding that barriers to interval meter data keep demand response from scaling in PJM, and stated that strong data access platforms are needed to reach target savings.

**Staff Response:** Staff thanks the commenter for the comment and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements, and metrics. Data access remains subject to the Board's AMI data access rules, and each EDC must describe the process and timeframe by which it will make customer data available to a customer's authorized aggregator.

**iv. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, Mission:data, NJCCC, SEIA/CCSA/NJSEC, Smart Thermostat Coalition, and VGIC

Advanced Energy United, the BTM Coalition, NJCCC, and SEIA/CCSA/NJSEC supported clearer participation pathways for battery storage, with SEIA/CCSA/NJSEC specifically focused on existing battery resources. Advanced Energy United requested firm participation pathways during 2027–2029 for exporting BTM storage, bidirectional EV charging systems, and FOM storage, noting that only approximately 150 of New Jersey's roughly 15,000 residential batteries can currently provide grid services. It recommended that both battery export and bidirectional EV charging be explicitly enabled and compensated. SEIA/CCSA/NJSEC requested a functional pathway for existing BESS that includes event-based compensation, workable aggregator participation, device-level performance measurement, and clear export and dispatch rules, warning that more than 79 MW of deployed residential and small-commercial storage could remain excluded if existing demand-response resources consume most ofthe 3% target. NJCCC asked the Board to confirm that FOM distribution-connected storage is eligible. The BTM Coalition suggested that storage should have its own program mechanics because it can be dispatched more often than traditional DR.

**Staff Response:** Staff notes that existing BTM residential storage is addressed in this Order. Staff views V2G technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw proposal. As indicated in the Order, the VPP Interim program is just the first step in building out a robust market for storage and grid services.

SEIA/CCSA/NJSEC and the Smart Thermostat Coalition both recommended no minimum aggregation threshold. SEIA/CCSA/NJSEC stated that storage programs enroll systems individually rather than as a fully fleshed out aggregation. They suggested that if a measure is kept it should be based on deliverable capacity with payment on actual performance. SEIA/CCSA/NJSEC further recommended that the total size should only be used for program tracking purposes. The Smart Thermostat Coalition recommended relying on aggregator licensing and performance standards instead.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order retains a 10 kW minimum aggregation size per program event for the VPP Interim Program, which applies to the aggregation rather than to each device.

EEA-NJ and VGIC both supported the 10 kW Interim threshold. EEA-NJ asked the Board to clarify that thresholds apply to aggregations, not individual devices, and supported separate residential and C&I thresholds. VGIC stated that a 100 kW threshold would hinder residential bidirectional chargers, which operate at about 10 kW.

**Staff Response:** Staff thanks the commenters for the comment and notes that the 10 kW aggregation minimum is in the Order.

Advanced Energy United, the BTM Coalition, and VGIC recommended applying required communication standards at the aggregator or cloud level rather than at the individual-device level to avoid additional hardware costs and vendor lock-in. SEIA/CCSA/NJSEC similarly stated that communication standards are useful for connecting head-end systems, such as aggregators and edge DERMS platforms, but generally should not be imposed on individual devices. It recommended outcome-oriented interoperability requirements rather than requiring every device to support every listed protocol at launch, including acceptance of OpenADR 2.0b during the Interim Program, support for OpenADR 3.0 and IEEE 2030.5 where commercially available, application of CTA-2045 only to compatible devices, and acceptance of secure equivalent APIs or vendor protocols that satisfy applicable testing, cybersecurity, telemetry, and dispatch requirements.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Straw Proposal indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services. The Order requires each EDC to accept devices using any

open-standard communication protocol supported by its systems and does not require a specific protocol at the device level.

The BTM Coalition, ChargEVC, the Smart Thermostat Coalition, and VGIC all supported device-level telemetry for measuring performance. The BTM Coalition recommended using device-level battery telemetry to determine participant performance and compensation, while reserving AMI-with-baseline methodologies for technologies that cannot provide direct measurement. It stated that AMI data could still support program-level EM&V and PJM capacity-savings allocation. ChargEVC stated that M&V should not require a secondary utility meter, and the Smart Thermostat Coalition supported randomized controlled trials alongside AMI baselines.

**Staff Response:** Staff thanks the commenters for the comment. Staff notes that the PowerUp NJ Working Group will help develop future metrics and protocols.

Advanced Energy United and VGIC requested explicit eligibility for bidirectional EV charging, while ChargEVC recommended treating managed charging and vehicle-to-grid ("V2G") systems as two distinct eligible DER types because they provide different grid services. VGIC asked that V2G resources and electric school buses be included in the Interim Program and that installed backup-only bidirectional systems be allowed to reconfigure for grid-parallel operation. ChargEVC explained that managed charging provides load reduction and load shifting, while V2G provides injectable energy and dispatchable capacity, and recommended that both services be eligible and compensated according to the value provided. ChargEVC also recommended that a transportable resource that neither exports to nor operates in parallel with the distribution system be exempt from utility interconnection approval, with access to a standardized and expedited review pathway if it later connects or exports. Advanced Energy United recommended updating interconnection rules to reflect the latest available standards, versions, and publication years; establishing workable pathways for grid-parallel bidirectional charging; exempting grid-islanded backup-only and load-only modes; and allowing future standards or supplements to be incorporated without reopening the applicable rules.

**Staff Response:** Staff views V2G technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw proposal.

Mission:data stated that the AMI rules at N.J.A.C. 14:5-10 allow either automated Green Button Connect or manual Green Button Download, while the Straw Proposal assumes automated access. It recommended aligning both to require automated Green Button Connect, citing a recent FERC finding that manual data access is inadequate.

**Staff Response:** The AMI Data Access rules were adopted according to a rulemaking schedule initiated before this proceeding and represents a balance needed to prevent unnecessary investments and reflect uncertainty in energy market requirements for VPP programs at the time of drafting. Board staff continues to monitor the market and review if there is a need to update the rules. Staff also notes that the Green Button Data Standard is not the only available method for sharing customer data. The rules contemplate third-party access to AMI Data through Electronic Data Interchange and access to flat files.

**v. Advocacy Groups**

Commenter(s) Referenced in This Summary: ACEEE, Ceres, Evergreen Action and EDF, NEEP, New Jersey LCV, NJECN, NJEJA, Sierra Club, and Vote Solar

Evergreen Action and EDF, NJECN, NJEJA, and Vote Solar all favored a low or no minimum aggregation threshold so smaller residential and lower-income participants are not excluded. Evergreen Action and EDF recommended setting thresholds by service and grid level rather than customer class, lowering the 20 kW distribution threshold to 10 kW, and tracking both enrolled and delivered capacity. NJEJA proposed reserving a 10 kW threshold for overburdened communities. NJECN questioned whether any minimum is needed. Vote Solar recommended no minimumthreshold for the Interim Program and the long-term retail market, though suggested basing minimum threshold on enrolled capacity if a threshold is kept, and possibly setting a separate, higher C&I threshold.

**Staff Response:** Staff thanks the commenters for the comment. The proposed 10 kW minimum aggregation size from the Straw Proposal remains in the Order, as do the communication standards.

Evergreen Action and EDF and NJEJA both supported open, non-proprietary communication standards. Evergreen Action and EDF stated that EDCs should have Green Button and EDI portals running by July 1, 2027, and asked the Board to approve telemetry-based measurement as an alternative. NJEJA proposed five-minute AMI data for all DERs and sub-

minute telemetry for small BTM assets in overburdened communities, funded by a DER surcharge rebated to LMI customers.

**Staff Response:** The AMI Data Access rules were adopted according to a rulemaking schedule initiated before this proceeding and represent a balance needed to prevent unnecessary investments and reflect uncertainty in energy market requirements for VPP programs at the time of drafting. Board staff continues to monitor the market and review if there is a need to update the rules. Staff also notes that the Green Button Data Standard is not the only available method for sharing customer data. The rules contemplate third party access to AMI Data through Electronic Data Interchange and access to flat files. Staff notes as well that the Order allows flexibility in addressing the standards and provides opportunities for EDCs to propose alternatives.

New Jersey LCV, Sierra Club, and Vote Solar all asked for clear pathways for battery storage, including exporting BTM batteries (including EVs) and FOM storage. New Jersey LCV supported a broad portfolio, including thermostats, EV and bidirectional chargers, and heat pumps, and asked the Board to start with customers already in State-supported programs. Vote Solar asked for pathways for existing non-Triennium batteries, community storage, and community solar-plus-storage. Sierra Club supported community solar and EV participation, asked the Board to remove limits that keep homeowners from installing solar beyond their peak demand, and recommended a protective data-sharing protocol built to handle retail choice transactions and settlements.

**Staff Response:** Staff thanks the commenters for their comments and notes that the VPP Interim Program is designed as a clean energy, technology-neutral program, and each EDC proposes its eligible DER types, such as thermostats, EV chargers, and heat pumps, in its filing. The Order directs the EDCs to build on their Triennium 2 DR programs, starting with customers already in State-supported programs. BTM residential and small commercial batteries, new or existing, participate through Block 1 and may export where interconnected to do so under N.J.A.C. 14:8-5. FOM storage, community storage, community solar, and solar system size limits are outside the scope of this Order, and V2G compensation will be considered in the long-term framework. Data access remains subject to the Board's AMI data access rules at N.J.A.C. 14:5-10. Staff also notes that the Straw indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

Ceres asked the Board to recognize managed EV charging and V2G as eligible resources, with clear enrollment pathways, metering standards, and compensation.

> **Staff Response:** Staff views V2G technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw proposal.

NJECN recommended adding third-party aggregators such as Sunrun and Tesla right away, adopting secure protocols such as IEEE 1547.3 and IEEE 2030.5-2023, and adding rail and bus fleets and electric school buses in future programs.

> **Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

NEEP supported technology-neutral rates and eligibility that enable demand flexibility across connected appliances and load-shifting technologies. For low-income customers, NEEP recommended bill protections or guarantees to avoid increased costs and identified additional options, including exemptions for certain vulnerable populations, a low-income rate class, or fixed charges adjusted to reflect income, depending on the program's rollout and rate design.

> **Staff Response:** Staff thanks the commenters for the comment, technology neutral compensation based on the service provided to the grid is a founding principal laid out in the Straw. The Straw also outlines how other mechanisms, including TOU can support these types of programs.

In response to Stakeholder Comment No. 14, ACEEE recommended using the Interim Program to begin transitioning New Jersey from connected demand response toward enhanced, multi-season demand flexibility, while using the Long-Term Program to progress toward automated and fully grid-integrated VPP capabilities. ACEEE stated that both phases should develop increasingly sophisticated operational capabilities, performance-evaluation and verification systems, and dispatch protocols so aggregated DERs can serve as reliable load-shaping resources and displace more expensive generation, transmission, and distribution investments. Citing the EnergyHub VPP Maturity Model, ACEEE identified progressively greater resource availability, more granular scheduling and telemetry, improved performance accuracy, increased locational integration, and

greater operational autonomy as capabilities associated with more mature VPP programs.

**Staff Response:** Staff appreciates ACEEE's discussion of the capabilities needed to develop increasingly mature VPP programs. The Interim Program is intended to establish operational experience with resource enrollment, communications, dispatch, performance measurement, and verification while informing development of the long-term open-access framework. Staff agrees that the long-term framework should build upon verified Interim Program experience. The VPP Interim program is just the first step in building out a robust market for storage and grid services.

**vi. Program Implementers and Administrators**

Commenter(s) Referenced in This Summary: Energy Solutions, MaGrann, Michaels Energy, and Power TakeOff.

Michaels Energy asked the Board to expressly list thermal energy storage, controlled refrigeration, and industrial process loads as eligible C&I resources, and offered proposed rule language It considered the proposed 10 kW Interim and 100 kW long-term minimums reasonable as initial aggregation-level thresholds but recommended against applying them as device-level or minimum-customer-count requirements. It also recommended establishing a transparent, rolling technology-qualification process that would permit qualifying technologies to enter during the Interim Program without waiting for the next full procurement cycle.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. Staff notes that an aggregation is the collection of distinct units or parts, neither the Order nor Straw defines how those units or parts need to be aggregated or from where and neither the Order nor Straw calls for a procurement cycle.

Energy Solutions supported technology neutrality in the VPP Interim program. It emphasized the importance of data standardization and interoperability so that devices from multiple manufacturers and platforms can work together. Energy Solutions suggested that standards for valuation and measurement would also be necessary as VPP portfolios begin providing multiple grid services, and recommended coordination across frameworks.

**Staff Response:** Staff thanks the commenter and notes that the Order requires each EDC to accept devices using any open-standard communication protocol supported by its systems, and that obtaining operational data, testing communication protocols, and establishing data standards between EDCs and aggregators are some of the objectives of the VPP Interim Programs.

MaGrann stated that individually metered multifamily buildings face barriers because owners lack incentives to make upgrades, and encouraged mechanisms that align incentives between owners and residents.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The Straw mentions the need to address specific use cases in the future to ensure a robust market that makes these services available to all ratepayers.

Power TakeOff recommended that the Board consider a centralized EDC-contracted AMI data analysis provider to perform functions that do not require customer-facing market competition. It proposed using AMI and customer data to identify and recruit customers best suited to VPP participation, including LMI customers most likely to benefit from enrollment and avoid adverse bill impacts. Under its proposed model, the provider could apply targeting parameters supplied by third-party aggregators, identify and contact suitable customers, and, with customer permission, connect them with an EDC-contracted aggregator-of-aggregators, an appropriate third-party aggregator, or a public offer-comparison platform. Power TakeOff emphasized that this pathway would supplement rather than replace aggregator-led marketing and enrollment. It also recommended that the EDC-contracted provider perform enrollment verification, impartial AMI-based event-performance measurement and M&V, and meter-data disaggregation capable of distinguishing the contributions of multiple devices at one premise, subject to contractual neutrality and nondiscrimination protections.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order allows each EDC to deliver its program through EDC staff and contracted implementation contractors. The Order and the MFR require each EDC to describe how it will attribute performance where more than one device or program services the same customer. Verification of

program savings will be performed by an independent evaluator retained by the Board.

### vii. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

NRG supported technology neutrality and found the 10 kW Interim threshold reasonable, measured on enrolled capability with performance verified during events. It asked the Board to account for existing device fleets when applying communication standards. NRG also asked the Board to move AMI data upgrades forward without delaying the program, and to fix the common release form, which conflicts with existing customer contracts, and PSE&G's meter settings for 15-minute data.

**Staff Response:** Staff thanks the commenters for the comment and notes that the 10 kW threshold is contained in the Order. The AMI Data Access rules were adopted according to a rulemaking schedule initiated before this proceeding and represents a balance needed to prevent unnecessary investments and reflect uncertainty in energy market requirements for VPP programs at the time of drafting. Board staff continues to monitor the market and review if there is a need to update the rules. Staff also notes that the Green Button Data Standard is not the only available method for sharing customer data. The rules contemplate third party access to AMI Data through Electronic Data Interchange and access to flat files. Staff notes as well that the Order allows flexibility in addressing the standards and provides opportunities for EDCs to propose alternatives.

Base Power asked that third-party suppliers be defined separately from DER aggregators and be made directly eligible for the distribution portion of the value stack. It asked that BTM batteries in third-party supplier VPPs be able to inject into the system. It asked the Board to make explicit that AMI interval registration and settlement apply to exports as well as consumption. It also asked that third-party suppliers receive customer-authorized AMI data access on the same terms and timelines as aggregators, including assigned PLC and NSPL values. Base Power further asked the Board to direct the EDCs to revise their PLC and NSPL methodologies to permit negative values for exporting customers.

**Staff Response:** Staff thanks the commenter for the comment. Under the Order, a VPP provider is defined by the action it performs rather than by the type of entity performing it, and third-party electricity

suppliers are among the entities that may qualify. The Order allows exports from BTM storage under Block 1. The Order also directs each EDC to develop a plan to revise its PLC calculation and reporting methods to account for negative PLCs, and to file a summary of that plan with the Board by February 12, 2027. Data access remains subject to the Board's AMI data access rules at N.J.A.C. 14:5-10. Distribution value for third-party suppliers will be considered in the long-term open-access VPP tariff.

**viii. Government Agencies**

Commenter(s) Referenced in This Summary: SMRSA

SMRSA asked the Board to recognize renewable biogas CHP at wastewater plants as an eligible resource in both phases of the VPP. It stated that treatment plants cannot curtail essential operations but can increase or export on-site generation. SMRSA suggested a narrowly designed pilot or tariff for renewable CHP to address this without creating an overly-broad or costly statewide program.

**Staff Response:** Staff thanks the commenters for the comment. Due to the timelines involved, Staff does not anticipate that a pilot program could be stood up in time to incorporate into the Interim program but notes that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

**ix. Financial Services**

Commenter(s) Referenced in This Summary: Syntropic

Syntropic recommended a technology-neutral, open-standards policy that would allow technologies achieving equivalent performance, which it stated would reduce equipment costs and broaden LMI access. It recommended defining the incentive base to include the cost of making a home capable of safely hosting storage, whether through a traditional electrical-service upgrade or a code-compliant power control system, in addition to storage-equipment costs. Syntropic cited UL 3141-listed power control systems as a potentially lower-cost alternative to a full service upgrade. It further supported defining eligibility by performance rather than device type to prevent vendor lock-in and preserve competition on equipment costs.

**Staff Response:** The VPP Interim Program and the long-term tariff are intended to be compensation for the service provided to the grid and

are not intended to be hardware or installation incentives, other programs may provide those complimentary incentives where the Board deems them appropriate.

**x. Individuals and Academic Institutions**

Commenter(s) Referenced in This Summary: Bill Beren, Cammie Croft, Digital Verity, Michael Winka, Peak+, and UDelaware

Bill Beren asked the Board to remove limits that keep homeowners from installing solar beyond their peak demand, create tariffs and incentives that combine solar with heat pumps and EVs, revive the utility pole and parking-lot solar orders, and adopt V2G tariffs for light-, medium-, and heavy-duty EVs.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. Staff views V2G technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw proposal.

Cammie Croft asked the Board to make third-party-owned residential batteries eligible, so incentives can flow to owner-operators, including nonprofits using federal elective pay. She also suggested adding an affordability band for households at 80–150% of area median income ("AMI") alongside a binding LMI floor and extension of a defined share to moderate-income households. Cammie Croft left determination of an exact ceiling to Staff. She also asked the MFR Order to assign each EDC responsibility, with a firm date, for residential interval-data settlement.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The Order also includes the MFRs for GSESP Block 1 program which provides a pay for performance opportunity for residential batteries.

Michael Winka supported the minimum threshold for residential customers based on enrolled capacity, but suggested moving to deliverable capacity as data allows. He also recommended higher thresholds for C&I customers. Michael Winka asked that all four EDCs use the same open communication standards rather than utility-specific systems, as contractors and aggregators will be working across utility territories.

**Staff Response:** Staff thanks the commenters for the comment, the Order requires the EDCs together through the Working Group to establish statewide standards on a variety of issues

UDelaware asked the Board to recognize open standards for AC V2G charging, including SAE J3072, SAE J3068, UL 1741-SC, and OCPP 2.1, along with IEEE 1547-2018.

**Staff Response:** Staff acknowledges the comment and notes that the Order does not create a separate definition or program for V2G. V2G-capable vehicles are treated as a form of customer-sited storage, and V2G compensation will be considered in the long-term framework. The protocols listed in the Order are not exclusive, and each EDC must describe its roadmap for expanding protocol support.

Digital Verity recommended evaluating aggregated bidirectional batteries as a utility-scale resource, noting that they respond in under a second and can swing twice their rated capacity when reversing, which creates aggregate risks that load-control devices do not.

**Staff Response:** Staff views bi-directional battery technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw proposal.

Peak+ recommended evaporative precooling of C&I air-cooled equipment, referred to as adiabatic precooling, as a permanent peak-reduction measure to save more power on the hottest days of the year. It stated that standard Wi-Fi thermostats do not work on many C&I systems and that a 10 kW threshold excludes small businesses with a single 5-ton unit. Peak+ also stated that selective shut-off of EV charging could leave drivers unable to charge. It stated that there will not be enough battery storage to have an impact by the program's in-service date, that using batteries for multiple demand response purposes may raise issues, and that battery telemetry must work and be on a Uninterruptible Power Supply ("UPS") or battery backup system. Peak+ stated that remote BMS activation shows promise, but that fewer than half of BMS systems are managed by someone who can set up a tailored curtailment plan, and that curtailment may cause tenant discomfort on the hottest days.

**Staff Response:** Staff thanks the commenter for the comment. The VPP Interim Program is technology-neutral and open to all DER types capable of delivering dispatchable demand reduction on a reliable, event-driven basis, and each EDC proposes its eligible device types in

its filing. The Order limits customer impacts through its event parameters, including a maximum event duration of three hours, advance notification, and customer opt-out rights for any individual event. Block 1 makes a separate performance incentive available to 100 MW of existing residential and small commercial storage, and participating systems must measure charge and discharge at the device level and report interval data to verify performance. Staff also notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

# 3. Budget, Targets & Cost-Effectiveness

***Straw Proposal section(s):*** *§ 2.1(i), § 2.4, § 2.6, § 2.7, § 2.9(iii), Appendix A*

**Summary of Comments:** Commenters were divided on the 3% target. Most utilities and several technology providers asked that it be a non-binding or EDC-specific planning benchmark, while several trade associations, advocates, and Rate Counsel treated it as a floor, and some proposed 10% or more. Many commenters, led by Tesla and the solar and storage associations, urged Peak Shaving Adjustments so that reductions lower zonal capacity obligations rather than only shifting costs through 5CP. Views on the budgets split: PSE&G, RECO, Uplight, and SEIA/CCSA/NJSEC found them too small, Rate Counsel found them too large relative to savings, and several commenters noted wide differences in funding per MW across EDCs. Most commenters asked to keep hardware incentives in their existing programs. Nearly all commenters other than Rate Counsel and ev.energy opposed using the RIM test as the primary cost-effectiveness test, favoring the TRC, NJCT, or PACT. Commenters also asked for location-specific avoided T&D methods tied to specific deferred projects, and for regular updates to the $60 million estimate.

### xi. Utilities and Utilities Association

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, RECO, and NJNG

ACE, JCP&L, NJUA, and RECO all asked the Board not to apply 3% as a uniform, binding target at the start. NJUA asked the Board to explain how the target was calculated, why it is uniform across EDCs, and how it relates to the budgets, noting the lack of EDC-specific potential studies. JCP&L recommended EDC-specific targets based on each territory's technical, economic, achievable, and programmatic potential and on realistic launch timelines. ACE viewed 3% as a statewide planning benchmark for the end of the Interim Program, with EDC-specific targets set through the MFR filings and lowered if the Board approves a smaller portfolio. RECO

recommended treating 3% as a non-binding reference beginning July 1, 2027, with a goal of reaching 3% by 2029.

**Staff Response:** Staff acknowledges the comments and notes that the Order sets a peak demand reduction goal for the VPP Interim Programs of no less than three (3) percent of each EDC's service-territory peak load, based on PJM Summer weather-normalized coincident peak data. In setting this goal, Staff considered many factors, including, but not limited to, the existing devices in each EDC's service territory that were already funded through prior EE and EV programs, and expects that enrolling a significant share of these devices will allow the goal to be met quickly. The budgets were set by reviewing existing DR program budgets and the maturity of each EDC's DR programs, with each EDC's allocation starting from its share of coincident peak and adjusted from program infrastructure already in place. The Order also requires each EDC to propose its own target in MW for each program year, with supporting assumptions, and to justify any target below this level. The VPP Interim Program runs from October 1, 2027 through September 30, 2029, and recovery of prudently incurred costs is not conditioned on achieving the target.

JCP&L and NJUA both stated that reductions from existing DR and pilot programs should count toward the target unless the Board defines the target as incremental and sets a baseline method for it. JCP&L asked the Board to decide whether targets are measured on enrolled, available, or verified delivered capacity. NJUA asked for clarity on baselines and on how participation in both distribution-level and wholesale DR programs should be reflected.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements, and metrics, including how to best quantify the savings that VPPs can produce at all levels. Staff notes that the target is measured as verified load reduction, and resources that migrate from the Triennium 2 DR programs into the VPP Interim Program may count toward it.

NJUA, PSE&G, and RECO all stated that the proposed budgets may not be enough to meet the target. PSE&G calculated that its $30 million budget would fund about 109 MW for one year at ConnectedSolutions incentive levels, against a 306.9 MW target, and noted that its Triennium 2 DR filing budgeted about $26 million for 95 MW. RECO modeled a portfolio delivering 62.2 MW over 2027–2029 at a cost of $8.79 million, against its

proposed $2 million. NJUA stated that the budget is lower than existing Triennium 2 DR budgets and that administrative costs may be underestimated, and asked for flexibility to move funds among offerings. JCP&L asked the Board to explain how the budgets relate to participation forecasts, cost to achieve, and expected impacts.

**Staff Response:** The Order has revised budgets that take into account stakeholder feedback, existing demand response and VPP programs, and the budget for those programs. The budgets in the Order serve as guidance, and an EDC may propose a different budget with a detailed written justification if it deviates by more than fifteen (15) percent.

ACE and RECO disagreed on hardware incentives. ACE recommended keeping them outside the VPP budget to avoid paying for the same device through GSESP Phase 2, Clean Transportation, and Triennium programs. RECO recommended including them in the VPP budget and moving Triennium hardware incentives into the VPP, stating that splitting costs across programs makes cost-effectiveness harder to assess.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that unlocking these multiple compensation streams while guarding against double payment is a long-term goal. Staff also notes that the Straw contemplates EE and EV hardware incentives remain within those proceedings and are not considering double payment, the straw also suggests looking at ways to encourage VPP participating with incentivized hardware. Staff also notes that the VPP program is intended to compensate for services to the grid, it is not intended to be a hardware or installation incentive.

ACE, PSE&G, and RECO all opposed using the RIM test as the primary cost-effectiveness test. ACE recommended the TRC and NJCT as primary tests, using avoided costs validated through the PSUP, and evaluating the full value stack. PSE&G stated that the RIM test measures lost sales rather than cost-effectiveness and recommended starting with a TRC that includes environmental and State policy benefits. RECO recommended the TRC or NJCT. NJUA recommended using the existing Triennium 2 TRC test for the Interim Program while better DER-specific methods are developed. JCP&L asked the Board to set cost-effectiveness, EM&V, and locational value methods before EDCs finalize program designs, to assess cost-effectiveness at the individual program level, and to avoid uniform statewide assumptions about distribution benefits.

**Staff Response:** Staff notes that the Straw Proposal indicated that this program should be reviewed based on the savings provided, not any additional social or environmental goals, which is why RIM test was selected. Staff also would prefer to develop new metrics that more readily reflect the true nature of these programs, which is what was requested in the Straw proposal. Staff acknowledges that in standing up these programs, it is important to align with the existing requirements and expects that the EM&V subgroup of the PowerUp NJ Working Group will continue to work to develop a more refined test in the future. The Order also excludes utility lost distribution revenue from all six (6) tests and requires each EDC to report results under all six cost tests.

PSE&G and RECO differed on the savings estimate. PSE&G stated that Table 1 in the Straw Proposal uses NSPL rather than the coincident peak that sets PLC, and recommended recalculating savings from PLC using the zonal scaling factor and forecast pool requirement. It also stated that the 91% capacity accreditation assumption is overstated, since storage is accredited at 58–78%, solar at under 10%, and EVs not at all, and that load shifting may not reduce zonal transmission obligations proportionally. RECO found the $60 million estimate and Table 1 figures reasonable, but recommended that underlying assumptions continue to be refined and validated. RECO recommended adding avoided T&D costs in the future, and preferred measuring maximum coincident peak reduction over average performance.

**Staff Response:** Staff thanks the commenters for their comments and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements, and metrics, including how to best quantify the savings that VPPs can produce at all levels. Staff notes that the Order therefore bases the reference values on PJM's Summer 2025 weather-normalized RTO coincident peaks rather than NSPL, and requires the EDCs to submit PSA plans to PJM to produce zonal reductions. Staff also included the Attachment F to this Order to further justify the use of the 5CP and NSPL values.

NJNG stated that the 3% target equals about 439 MW and that using 20% of New Jersey's roughly 2,224 MW of residential natural gas backup generation could provide about 445 MW. It recommended that evaluation focus on avoided capacity costs, deferred T&D investment, and measurable ratepayer savings.

**Staff Response:** Staff thanks the commenters for the comment and notes similar targets are reflected in the Order and the Straw. Staff also

notes that the VPP program was designed as a clean energy, technology-neutral program.

### xii. Division of Rate Counsel

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel supported the RIM test as the primary cost-effectiveness test because it shows whether non-participants' rates rise. It recommended that EDCs report the other tests as well and that continuation depend on actual, not forecast, RIM results. It cautioned that a program could pass the RIM test and still raise total bills if it duplicates existing resources or buys more capacity than needed.

**Staff Response:** Staff acknowledges the comments and notes that the Order makes the RIM test the primary test at the portfolio level and requires each EDC to report results under all six tests. Each EDC must also report annual benefit-cost ratios under all six tests using actual costs and verified savings, and the Midterm Review will assess program cost-effectiveness and performance. The Order further requires a bill impact analysis and prohibits counting the same load reduction under more than one program.

Rate Counsel stated that no New Jersey analysis shows VPPs are cheaper than alternatives such as gas plants, transmission, or distribution upgrades, and that the national estimate cited in the Straw Proposal does not reflect New Jersey conditions. It stated that the $60 million estimate is gross, excludes program costs, and falls to about $42.6 million at the 64% realization factor. Rate Counsel asked that analyses include all costs, including incentives, DERMS, AMI, interconnection and distribution upgrades, administration, and utility returns, and count wholesale revenues and avoided costs only when they reach customers. It also recommended New Jersey-specific baselines, sensitivity cases, benefits that materially exceed costs, and annual true-ups.

**Staff Response:** Staff acknowledges the concerns and notes that each EDC's filing will provide a New Jersey-specific analysis using the cost test methodologies and assumptions provided by Staff. The BCA (as shown in Attachment F) does not compare VPPs to a specific alternative, such as a gas plant. Instead, it counts avoided capacity, transmission, and distribution costs as benefits, and each EDC must show a benefit-to-cost ratio greater than 1.0 under the RIM test (the primary test). For each benefit and cost line item, the Order and the

MFR require the EDC to show the quantity, unit value, derivation, and input sources, along with a sensitivity showing the effect of reasonable high and low values. Each EDC must also show how capacity and transmission savings reach customer bills through the BGS auction. Program costs, including customer incentives and administration, are expected to be recovered as Operating Expense with no return and are subject to annual reconciliation. Additionally, this program is designed to meet the requirements set forth in EO 1 and EO 2 to begin development of a VPP program within 180 days and to move quickly to provide cost savings to ratepayers.

Rate Counsel questioned how the EDC budgets were set. Rate Counsel took issue with the Straw's estimated two-year savings of $122.6 million against about $68 million in budgets, leaving about 45% of savings for customers, with ACE's $20 million budget exceeding its $17 million in savings and RECO returning only 23%. It recommended including hardware incentive costs in the budget and focusing EDCs on low-cost measures, such as demand rates tied to PJM peaks. Rate Counsel also supported advancing Triennium programs without waiting for the VPP and placing all similar DR programs under the VPP Program.

**Staff Response:** Staff appreciates the comments and notes that the Order describes how the budgets were set: Staff reviewed existing DR budgets, the maturity of each EDC's existing programs, EDC comments, and other stakeholder input, and allocated the budgets starting from each EDC's share of coincident peak, adjusted for program infrastructure already in place. The budgets serve as guidance, and each EDC must demonstrate how its proposed program is designed to achieve a benefit-to-cost ratio greater than 1.0 under the RIM test. Hardware incentives remain under other Board-approved programs, and the Order directs the EDCs to use their Triennium 2 DR programs as the foundation of the VPP Interim Program. The VPP program, both short and long term is designed to provide compensation for the service provided to the grid, it was not designed in the Straw or Order as a hardware and installation incentive, the Straw did suggest that future hardware incentives in coordinating programs could require participation in a VPP to unlock the most value from the devices.

Rate Counsel questioned whether the 3% target and July 1, 2027 date are realistic given the filing and approval schedule and asked when the target applies and how it would lower rates. It also asked when, and by how much, the program would reduce New Jersey's capacity commitment, since the

PJM auctions for the 2029/2030 and 2030/2031 delivery years are scheduled for December 2026 and May 2027. It stated that 3% appears attainable and should be a floor, recommended meeting it by the end of year one with a higher target for year two, and recommended partial cost disallowance when an EDC misses its target.

**Staff Response:** As EO 1 and EO 2 point out, ratepayers deserve to see savings as quickly as possible. VPPs have the potential to unlock that savings quickly and effectively, waiting to study solutions that we know can provide meaningful impacts denies ratepayers relief, which is why the BPU proposed an interim program that provides an opportunity for EDCs to provide feedback and data on the impact of these programs quickly. Staff also notes that the Order sets the 3% peak shave as the expectation, with the VPP Interim Program running from October 1, 2027 through September 30, 2029, and directs Staff to evaluate a shared-savings mechanisms for EDCs that exceed that target. Recovery of prudently incurred costs is not conditioned on achieving the target.

Rate Counsel questioned crediting VPPs with avoided T&D costs, noting that a 240 kW reduction at a substation serving 4,000 customers is likely a rounding error and that a resource called for a system event may not be available for a local event the same day. It recommended adding T&D benefits only on a project-specific basis after a VPP has shown it delivers them.

**Staff Response:** Staff acknowledges the concerns and notes that each EDC must support any avoided transmission or distribution value it claims with its methodology, unit value, and input sources, subject to Board review in its petition. Attachment A also requires each EDC to report load reduction during distribution and other grid stress events separately from load reduction during the 5CP hours. Quantifying distribution-level grid service values is an objective of the VPP Interim Program, to build the evidence needed before any future procurement of locational distribution benefits.

**xiii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, Electrify America, EnergyHub, ev.energy, Foley, Honeywell, Koolbridge, Logical Buildings, Lunar ModernElectric, Nexamp, NJRCEV, Oracle, PACE AI Piclo, Recurve, Renew Home, RExChain, Solar Landscape, Soltage,

Steffes, Tesla, Turtle & Hughes, Uplight, Virtual Peaker, Voltus, and WeaveGrid

EnergyHub, Honeywell, and Uplight recommended treating the three-percent target as a planning reference rather than a binding requirement at launch. EnergyHub recommended EDC-specific targets based on each utility's load shape, DER saturation, and non-wires priorities. Uplight recommended allowing EDCs to phase toward their MW targets during the first six to twelve months as customer enrollment, DER integrations, and operational capabilities scale, with targets differing by EDC under a common statewide methodology. Recurve revised its earlier three-to-five-percent recommendation and proposed a phased, evidence-based ramp. For Year 1, Recurve recommended setting each EDC's target through a bottom-up count of enrolled, forward-compatible assets and treating that target as a floor rather than a ceiling. For Year 2, it recommended resetting the target using verified Year 1 M&V data, actual enrollment growth rates, and confirmed budget levels, with movement toward three percent or higher occurring only alongside proportional budget scaling. For the long-term tariff, Recurve recommended allowing the compensation framework and open aggregator market to determine participation rather than centrally mandating a percentage target. Honeywell requested that each EDC file its baseline, target-setting methodology, deliverable capability, costs, and verified results.

> **Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the Power Up Working Group will help establish future goals, measurements and metrics, including how to best quantify all savings provided by VPPs. The Order sets three (3) percent as a minimum, and each EDC must propose its own MW target for each program year and justify any target above or below that level. The Midterm Report will provide the Board with an opportunity to review and adjust the program after 12 months.

ev.energy and Renew Home both supported 3% as a floor, and Voltus and Piclo urged higher goals. ev.energy stated that 3% should be a floor for EDCs to build on and that the Board should also consider everyday load shifting. Renew Home supported a binding floor and asked the Board to treat it as a procurement trigger, with success measured by capacity delivered to customers and system costs avoided, rather than by the percentage reached. It stated that any target should be tied directly to the statewide, systemwide need to reduce supply, capacity, and grid investment costs, and that a utility reaching 2.8% while dispatching a well-

utilized portfolio into the hours that set capacity obligations delivers more customer value than one reporting 3.1% from resources that are rarely called. Renew Home also recommended against relying only on 5CP to measure avoided cost value, noting that PJM's PSA uses THI signals to reduce the zonal load forecast and, in turn, capacity obligations. It asked that distribution value be a separate value stack from wholesale demand flexibility value. Voltus recommended a target of 10% of EDC peak load reduced through VPP aggregation by February 1, 2028 and 20% by 2030, noting that smart thermostat potential alone is about 776 MW. Piclo suggested the Board consider supplementing detailed per-EDC targets with a simple headline goal, such as 1 GW of VPP dispatch capability by 2030.

**Staff Response:** Staff thanks the commenters for the comments and agrees that a peak demand reduction target is useful only if it lowers costs to ratepayers. The Order ties the target to customer savings in three ways: (1) dispatch events are informed by a forecast of PJM's 5CP hours, the 1 transmission CP, and grid stress events and the VPP Interim target is measured as verified load reduction averaged across the 5 CP hours to ensure consistent measurement throughout the PowerUp NJ Program; (2) each EDC must submit an annual PSA plan which details their dispatch protocol, to PJM so that verified reduction lower the peak load contribution on which capacity is procured for its zone; (3) alongside the three percent minimum demand reduction target, each EDC can propose a higher target; EDCs must also propose cost savings goals for participant savings and avoided costs (e.g., T&D, Capacity, Energy), expressed in nominal dollars and as an impact on residential rates, and must report verified savings and cost to achieve ($/kW) each year. The design of the Interim Program provides an opportunity to provide ratepayers with short term savings while at the same time beginning to develop learnings and metrics around savings that can be realized on the transmission and distribution level. The EM&V subgroup of the PowerUp NJ Working Group will help refine future goals and metrics.

Tesla recommended that the Board stop using 5CP or PLC as the main basis for targets and capacity savings, and instead direct EDCs to file PJM Peak Shaving Adjustment (PSA) plans under Manual 19. It stated that lowering individual customers' PLCs shifts costs among customers, while only a lower zonal capacity obligation reduces costs for all ratepayers, and that the program's value depends on that mechanism more than on the target level.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements and metrics. Staff also notes that the Order requires that both system and zonal savings be measured and requires each EDC to submit a PSA plan to PJM by September 10 of each year, beginning in 2027. Peak load is defined consistently throughout the PowerUp NJ Program to ensure there is a consistent baseline across the portfolio.

Solar Landscape, Uplight, and ev.energy all addressed the peak-load basis. Uplight recommended PJM 5CP/PLC as the primary basis for the Phase 1 target, with distribution performance reported separately. Solar Landscape recommended 5CP/PLC for capacity value and NSPL for transmission value, tracked separately. ev.energy accepted NSPL for the Interim Program but recommended evaluating 5CP/PLC for the long-term tariff.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements, and metrics. Staff notes that the Order directs the EDCs to measure verified load reduction across PJM's five (5) coincident peak (5CP) hours, and the 1 transmission CP and grid dispatch events as defined by the EDCs, and that load reduction during distribution and other grid stress events is reported separately.

Logical Buildings characterized the three-percent target and approximately $60 million avoided-capacity estimate as planning references rather than guaranteed savings, noting that actual value will depend on performance, capacity prices, PJM recognition, load-forecast treatment, and avoidance of double counting. Piclo supported aggressive targets and described the estimate as a useful order-of-magnitude reference, while deferring detailed target-setting methodology to the EDCs and load-forecasting experts. Solar Landscape described the estimate as a useful directional indicator that should not cap program value or compensation and recommended updating it as capacity prices, EDC load forecasts, and verified performance change. Uplight similarly recommended using the capacity prices applicable to the PJM Delivery Years in which savings would occur and to evaluate the Interim program budgets relative to measurable avoided cost values including avoided capacity costs attributable to the EDC's PSA plans. Uplight and Solar Landscape also recommended separately incorporating measurable avoided transmission and distribution costs into future estimates.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements and metrics, including how to best quantify all savings provided by VPPs. Staff intends for the working group to be an avenue for further discussion between Board Staff, the EDCs, the Division of Rate Counsel, and other interested stakeholders.

Calibrant, Honeywell, Logical Buildings, Solar Landscape, and Virtual Peaker all asked EDC filings to break out budgets by cost category. Logical Buildings and Honeywell asked that customer incentives, integration and telemetry, M&V, aggregator or contractor compensation, and administration be shown separately. Calibrant asked EDCs to disclose the incentive budget and expected $/kW rate. Virtual Peaker recommended that each EDC separately itemize incremental technology and integration costs from general administration, with sufficient detail to demonstrate that the proposed funding can support actual DERMS integration work. It specifically expressed concern that RECO's proposed $2 million program budget may be insufficient to fund both enrollment operations and the technology integration needed to achieve the Tier 1 and Tier 2 milestones. Solar Landscape asked that MFR filings identify, by program and resource type, expected enrolled capacity, dependable or delivered peak reduction, participant counts, customer and aggregator compensation, administrative and implementation expenses, EM&V and marketing costs, and expected cost to achieve in $/kW. It also recommended distinguishing one-time start-up and integration costs from recurring program costs and explaining how proposed expenditures would achieve the applicable peak-reduction target. Solar Landscape further recommended that the Board assess measurable ratepayer value by comparing proposed budgets against the expected value of the peak reduction and grid services procured rather than applying an arbitrary spending ceiling.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics. Staff also notes that the Order contains a variety of reporting mechanisms. Staff intends for the working group to be an avenue for further discussion between Board Staff, the EDCs, the Division of Rate Counsel, and other interested stakeholders.

RExChain, Solar Landscape, and Uplight all noted large differences in budget per MW across EDCs. RExChain calculated incentive intensity

ranging from approximately $42,500 per MW-year for JCP&L to approximately $123,000 per MW-year for ACE and recommended requiring each EDC's MFR budget and cost-effectiveness worksheet to disclose and explain how its proposed incentive intensity compares with the applicable PJM Base Residual Auction capacity price and Basic Generation Service auction-cleared energy price. RExChain clarified that it was not recommending that incentives equal those reference prices, but that the comparison would help distinguish legitimate cost differences from inconsistent EDC budget-setting methodologies. Solar Landscape calculated whole-program budgets of approximately $98,000 per MW for PSE&G, $85,000 for JCP&L, $246,000 for ACE, and $157,000 for RECO. Uplight stated that the budgets are insufficient to support the Interim Program's MW goals and should be evaluated against the avoided costs created by the VPP. Electrify America asked the Board to establish a minimum share of each budget for customer incentives and aggregator compensation and a ceiling on administrative costs.

> **Staff Response:** Staff thanks the commenters for the comments and notes that the Order has revised budgets that consider stakeholder feedback, existing demand response and VPP programs, and the budget for those programs. The EDCs can propose budgets that differ beyond 15% of the proposed budgets in the Order with a detailed narrative about why such an increase is necessary.

ev.energy, Renew Home, and WeaveGrid all asked for budget flexibility. ev.energy recommended treating the budgets as starting floors to adjust once enrollment is known. Renew Home found the budgets reasonable and asked that EDCs be able to move funds among pathways without a new filing. WeaveGrid asked that EDCs be able to make reasonable enabling investments in Edge DERMS, data integration, telemetry, customer acquisition, marketing, measurement and verification, and program administration.

> **Staff Response:** Staff thanks the commenters for the comment. The budget in the Order serves as guidance, and an EDC may propose a different budget with a detailed written justification if it deviates by more than fifteen (15) percent.

EnergyHub, ev.energy, Honeywell, ModernElectric, and Renew Home all recommended keeping hardware incentives separate from the VPP budget. Honeywell recommended that the VPP budget fund only incremental enabling costs, such as communications integration and telemetry.

EnergyHub recommended structuring the VPP Interim Program budget around enrollment, participation, and performance incentives, benchmarked to regional peer programs. It stated that battery hardware incentives should remain separate to avoid duplicative compensation with GSESP Phase 2, and that the two budgets should be designed together even if administered separately, with clear rules preventing stacking payments for the same grid service. ModernElectric asked that storage incentives favor equipment that can enroll in a VPP. Logical Buildings supported using Triennium and GSESP funding for hardware only if those programs are running when enrollment begins and can serve multifamily buildings. Calibrant asked that the upfront-plus-performance payment structure be available to C&I storage and sized to C&I costs.

> **Staff Response:** Staff thanks the commenters for the comments and notes that, under the Order, hardware incentives continue to be offered through other Board-approved programs, provided those incentives do not duplicate VPP compensation. The VPP Interim Program builds on devices customers already own, and residential and small commercial BTM storage is compensated through GSESP Block 1. Each EDC must identify any incentive an enrolled customer receives under other programs and describe the safeguards that prevent double payment.

Logical Buildings, Renew Home, and Uplight opposed relying on the Ratepayer Impact Measure ("RIM") as the primary cost-effectiveness framework. Recurve likewise opposed Staff's suggestion to use RIM as the foundational test for either the preliminary program or the long-term market-based VPP program. Uplight recommended that the PACT, supplemented by the TRC and other relevant tests, serve as the primary basis for determining whether the VPP produces net benefits for ratepayers, with the RIM and PACT used as complementary indicators of rate and participant impacts. Renew Home stated that a statewide VPP surcharge would technically increase rates even where the program reduces customers' overall costs. Logical Buildings recommended presenting RIM, TRC, capacity value, and locational transmission and distribution value together under a single statewide methodology. Recurve recommended itemizing the value streams needed to support a long-term open market and using those values as the basis for compensation instead of relying on a single cost test. WeaveGrid did not object to retaining the existing tests but recommended updating their avoided-cost inputs to accurately reflect the time- and location-specific value of distributed flexibility.

**Staff Response:** The straw indicated that this program should be reviewed based on the savings provided, not any additional social or environmental goals, which is why RIM was selected. Staff also would prefer to develop new metrics that more readily reflect the true nature of these programs, which is what was requested in the Straw proposal. Staff acknowledges that in standing up these programs, it is important to align with the existing requirements and expects that the EM&V subgroup of the PowerUp Working Group will continue to work to develop a more refined test in the future.

ev.energy supported the RIM test as the primary test. It recommended adding an avoided-capacity metric that credits managed EV charging, tracking avoided fuel and emissions through the Societal Cost Test, and adopting a locational avoided-cost method modeled on the California Avoided Cost Calculator.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the Power Up Working Group to establish future goals, measurements and metrics, including how to best quantify all savings provided by VPPs. Staff intends for the working group to be an avenue for further discussion between Board Staff, the EDCs, the Division of Rate Counsel, and other interested stakeholders.

Several commenters recommended locational approaches for valuing avoided or deferred grid investments, although their proposals differed in scope. WeaveGrid recommended quantifying time- and location-dependent distribution value, including costs associated with avoided or deferred feeder, substation, transformer, and circuit investments, as well as voltage-related and distribution-loss costs. Uplight supported location-differentiated Pathway 2 compensation but recommended the Board establish broader capacity-need zones or tiers and increase granularly are not initially available, with increasing granularity as PSUP planning and DERMS capabilities mature. Virtual Peaker asked EDC filings to identify the specific capital projects that VPP resources are expected to defer. Soltage recommended that marginal cost-of-service methodologies used to derive T&D deferral values include at least ten years of system-expansion costs so that the modeled deferral period reflects the longer asset lives of energy storage and other DERs and the resulting potential for longer-term capital-investment deferral. Nexamp separately recommended transparent, location-specific benefit-cost analysis of FOM storage, informed by updated hosting-capacity maps, rather than limiting the program to a narrow set of customer-side applications. Honeywell

recommended requiring claimed system value to be supported by documented needs, location, timing, duration, and verified results.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the Power Up Working Group to establish future goals, measurements and metrics, including how to best quantify all savings provided by VPPs. Staff intends for the working group to be an avenue for further discussion between Board Staff, the EDCs, the Division of Rate Counsel, and other interested stakeholders.

DCO, Logical Buildings, and Oracle supported recognizing multiple, distinct value streams while preventing the same service or reduction from being credited twice. Oracle specifically recommended recognizing retail peak reduction, local distribution value, and customer load-shaping value as independent VPP services. It also recommended transparent measurement and evaluation protocols that prevent the same reduction from being credited twice while allowing resources to provide distinct services at the distribution, retail, and wholesale levels. Logical Buildings stated that customer bill savings and VPP payments should not be treated as duplicative merely because they are produced by the same resource. Lunar asked the Board to clarify in the MFR Order that anti-double-counting rules prohibit duplicate payment for an identical service through two programs, not payment for distinct services delivered during the same Dispatch Event. PACE AI separately supported allowing aggregated DERs to access multiple value streams simultaneously where each value stream independently benefits the grid. Addressing concerns regarding free riders, PACE AI recommended providing incentives for all value streams delivered by new assets and by existing assets that had not previously received an energy-efficiency or other incentive.

**Staff Response:** Staff notes that the long-term goal of the VPP is to unlock multiple compensation values for VPPs and DERs and that the Order includes anti- double counting provisions.

Koolbridge stated that reaching the 589 MW target through curtailment alone risks event fatigue and opt-outs during long events, citing utility reports of opt-outs as events approach four hours. It stated that source-switching through intelligent panels can deliver verified reductions while keeping household loads running.

**Staff Response:** Staff thanks the commenters for the comment and notes the technology neutral design will allow intelligent electrical panels participate as well as any new technologies that are brought to market.

Foley stated that the Straw Proposal's 64% performance case realistically recognizes that residential resources may not perform in severe weather, and that on-site generation provides firm capacity during grid stress and outages.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

Steffes asked that winter peak management and long-duration load shifting count toward target savings.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the Power Up Working Group to establish future goals, measurements and metrics. Staff also notes that the program includes opportunities for winter calls to address demand and requires the EDCs to develop the programs terms and conditions including eligible technologies.

NJRCEV recommended that the Board pursue near-term capacity savings by ensuring that distribution-level wholesale solar projects paired with storage or other firming technologies are treated as demand-side or load reductions in PJM forecasts. NJRCEV stated that this treatment would reduce New Jersey customers' capacity-cost allocations more efficiently than participating as supply in the standard PJM capacity market. It further stated that these projects could provide resiliency benefits, leverage existing infrastructure, and offer a streamlined strategy for adding near-term supply.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

Turtle & Hughes stated that a competitive VPP framework creates new opportunities for industrial, commercial, and office customers to manage energy, demand, and capacity costs.

**Staff Response:** Staff thanks the commenters for the comment and notes this is reflected in the Order.

**xiv. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, NJCCC, SEIA/CCSA/NJSEC, Smart Thermostat Coalition, and VGIC

Advanced Energy United and SEIA/CCSA/NJSEC both supported a target of at least 3%. Advanced Energy United noted that 3% is approximately 590 MW statewide, and asked for a more ambitious long-term target, but indicated that meeting 3% depends on its other recommendations for the Interim VPP. SEIA/CCSA/NJSEC recommended measuring the target on deliverable capacity, treating it as an initial planning goal, and raising EDC targets above 3% where potential is higher.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements and metrics. The Order sets three (3) percent as a minimum, and each EDC may propose a higher target. New targets may be contemplated after the Midterm report.

Advanced Energy United and the BTM Coalition recommended using a PJM Peak Shaving Adjustment mechanism, while SEIA/CCSA/NJSEC recommended obtaining ratepayer capacity savings through a Peak Shaving Load Adjustment or an equivalent mechanism under PJM Manual 18 or 19 that reduces New Jersey's zonal capacity-purchase obligation. SEIA/CCSA/NJSEC stated that targeting PJM's five coincident peaks primarily reallocates capacity costs among utilities within the zone rather than reducing New Jersey's total zonal capacity obligation. Advanced Energy United asked that the MFRs require a Peak Shaving Adjustment plan covering all VPP resources, including those administered by third-party suppliers. The BTM Coalition stated that the current PJM Peak Shaving Adjustment methodology relies on a Customer Baseline Load methodology that does not recognize battery or V2G exports. It recommended urging PJM to permit a Meter Generator Output baseline and, pending that change, immediately pursuing an interim forecast-adjustment mechanism under PJM Manual 19, Attachment B, that recognizes injection-capable resources.

**Staff Response:** Staff agrees that VPPs can drive down capacity, transmission and distribution costs. Staff agrees that a PSA can be an important tool to help lower zonal capacity costs; however, the VPP Interim Program is designed to build upon the existing demand response programs. The Straw Proposal and the Order note that the

VPP Interim Program is designed to bridge the gap until there is a tariff that DERs can participate in alongside additional wholesale compensation, and its focus is on building a program that provides stackable compensation for a variety of grid services, which may have a variety of different performance metrics. Staff notes that the Order requires a peak shaving goal based on call response during peak demand and the filing of a PSA to PJM each year. Staff will use this Interim Program to determine the best mechanism to achieve both long- and short-term savings and anticipates that EDCs will have feedback on these particular pieces in their Midterm Report. The Working Group established in the Order will also help develop measurements and metrics to realize savings.

ChargEVC, SEIA/CCSA/NJSEC, and the Smart Thermostat Coalition all asked for larger or more flexible budgets. SEIA/CCSA/NJSEC estimated that, if 85 percent of the proposed three-year budgets were allocated to performance payments, PSE&G's budget would provide approximately $27/kW-year and JCP&L's budget approximately $24/kW-year, amounts it considered insufficient to encourage broader participation. The Smart Thermostat Coalition recommended treating budgets as minimums that EDCs can exceed when spending remains cost-effective. ChargEVC recommended tracking costs and benefits and allowing more investment when benefits exceed costs. EEA-NJ asked that Interim Program budgets align with Triennium DER incentive budgets and that Triennium budgets not be reduced.

**Staff Response:** Staff notes that the Order has revised budgets that take into account stakeholder feedback, existing demand response and VPP programs, and the budget for those programs. The budgets in the Order serve as guidance, and an EDC may propose a different budget with a detailed written justification if it deviates by more than fifteen (15) percent.

EEA-NJ and SEIA/CCSA/NJSEC both recommended keeping hardware and storage incentives in their existing programs. EEA-NJ asked the Board not to condition Triennium or GSESP incentives on VPP enrollment and to offer an enrollment adder instead. SEIA/CCSA/NJSEC recommended funding any GSESP top-up incentive through what it termed the "system benefits charge" and funding performance compensation for power-supply services through utility power-supply adjusters.

**Staff Response:** The Straw proposed future incentives may be conditioned on participation in a VPP, but it did not propose immediate

changes to any specific programs. In many cases an adder is an interim step when developing such programs. The VPP Interim Program is designed as compensation for grid services and not a hardware or installation incentive.

EEA-NJ and the Smart Thermostat Coalition opposed using the RIM test as the primary cost-effectiveness test, while SEIA/CCSA/NJSEC supported applying New Jersey's full cost-effectiveness framework but stated that RIM should not determine the program's continuation by itself. EEA-NJ recommended the TRC or NJCT with National Standard Practice Manual practices. SEIA/CCSA/NJSEC stated that customer payments for grid services should not be counted only as a cost, and that the main question is whether the VPP produces net benefits for New Jersey. The Smart Thermostat Coalition recommended relying on the 2026 National Standard Practice Manual. VGIC asked that the TRC count only the incremental costs of managed and bidirectional charging, not baseline EV costs.

**Staff Response:** Staff refers to commenters to the Straw Proposal, which clearly states that the VPP is designed to save ratepayers money in both the long and short term, to do that effectively the program should be evaluated by those measures. Staff notes that based on all six (6) cost tests currently used are required under this Order and that the Order further tasks the EM&V subgroup of the PowerUp NJ Working Group with developing a metric that more appropriately captures all the benefits of a VPP program.

SEIA/CCSA/NJSEC and ChargEVC both recommended using interim avoided-cost values rather than delaying the program. SEIA/CCSA/NJSEC asked for a comprehensive avoided-cost study, citing a Maryland framework, and proposed an interim value of $200/kW-year. ChargEVC recommended provisional avoided capacity values in early phases that can be refined over time as greater information becomes available.

**Staff Response:** Staff thanks the commenters for the comments, the assumptions for the cost benefit analysis are contained in Attachment F and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics.

The BTM Coalition and VGIC both pointed to existing devices that could help meet the target. The BTM Coalition noted that Tesla and Sunrun alone have more than 10,000 residential batteries (at least 79 MW) installed in

New Jersey, and VGIC noted about 13,400 EVs with bidirectional charging capability.

**Staff Response:** Staff thanks commenters for the comments and notes that the Order references estimates for the number of existing devices and how they can contribute to the peak shave goal.

VGIC asked that each EDC filing include a specific participation or performance target for managed and bidirectional EV charging within its VPP target.

**Staff Response:** Staff views V2G technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw Proposal.

NJCCC stated that FOM distribution-connected storage can be deployed within two to three years and deliver measurable ratepayer benefits.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw indicates that the EDC-run VPP Interim Program is just the first step in building out a robust market for storage and grid services.

EEA-NJ recommended that, if the intent is to shift DER incentives out of the Triennium, Interim Program budgets be closely aligned with the utilities' Triennium budgets for DER incentives.

**Staff Response:** Staff thanks Commenters for the comments and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, build the market and lower peak demand while the Board stands up the long-term tariff. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff. The Order and Straw reference the Triennium budgets as part of the basis for the recommended budget for these programs.

VGIC stated that bidirectional EV charging is the lowest-cost storage option because customers have already bought the battery. It asked that any residential storage incentives also apply to bidirectional chargers but cover only the incremental cost of enabling bidirectional features, and that cost-

effectiveness tests count only the incremental costs of managed or bidirectional charging.

**Staff Response:** Staff views V2G technology as a form of storage and should be compensated as such as part of the long-term tariff contemplated in the Straw proposal.

### xv. Advocacy Groups

Commenter(s) Referenced in This Summary: ACEEE, Ceres, CJNJ, Evergreen Action and EDF, NEEP, New Jersey LCV, NJEJA, and Vote Solar

ACEEE, Evergreen Action and EDF, NEEP, and Vote Solar all opposed using the RIM test as the primary test. ACEEE stated that the RIM test mixes investment costs with rate distribution and counts reduced sales as a cost, and recommended the NJCT or PACT. NEEP recommended the New Jersey Cost Test (NJCT), possibly modified to fit the goals of VPP programs, as the primary test, with the RIM test functioning as a secondary check on rate impacts. Evergreen Action and EDF recommended a resource-value and avoided-cost framework and asked EDCs to at least report NJCT results. Vote Solar stated that the RIM test does not capture the distribution savings from VPP dispatch.

**Staff Response:** Staff agrees that it is inappropriate to include reduced energy sales as a cost for VPPs, and notes that the Straw Proposal indicated that this program should be reviewed based on the savings provided, not any additional social or environmental goals, which is why the RIM test was selected. Staff also would prefer to develop new metrics that more readily reflect the true nature of these programs, which is what was requested in the Straw Proposal. Staff acknowledges that in standing up these programs, it is important to align with the existing requirements and expects that the EM&V subgroup of the PowerUp NJ Working Group will continue to work to develop a more refined test in the future.

Evergreen Action and EDF, NEEP, New Jersey LCV, and Vote Solar all supported firm or higher targets. Vote Solar recommended a 10% binding floor, with higher EDC-specific targets based on energy burden and past reliability failures. Evergreen Action and EDF recommended making 3% the minimum acceptable filing, inviting EDCs to propose more, and commissioning a statewide potential study. NEEP and New Jersey LCV

asked for long-term targets, with New Jersey LCV proposing statewide targets for 2030 and 2035.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order establishes the goal as no less than 3% peak shave, which each EDC may exceed, and also tasks the EM&V subgroup of the PowerUp NJ Working Group to establish future goals and metrics. Any EDC filing that proposes a goal of less than 3% will need to justify that change.

CJNJ argued that voluntary, market-driven DER adoption would not achieve deployment at the scale and speed needed to address New Jersey's energy-affordability emergency. It recommended a utility-led Networked Power Program with a statewide capacity-procurement target allocated among the EDCs according to each utility's share of system load, subject to Board review for cost-effectiveness. As support for the urgency of its proposal, CJNJ cited PJM's auction clearing at the $325/MW-day price cap and a 6.8 GW shortfall below the regional reserve-margin target, and argued that voluntary enrollment would not achieve the Straw Proposal's 3% peak-demand-reduction goal quickly enough.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

Ceres, Evergreen Action and EDF, NEEP, and Vote Solar each identified broader system benefits that should be recognized in evaluating VPPs, although the specific benefits they identified differed. Evergreen Action and EDF identified avoided energy, generation-capacity, transmission- and distribution-capacity, and deferred-infrastructure costs, together with ancillary services, reliability and resilience, emissions, and community benefits. Vote Solar recommended including savings from PJM capacity obligations, avoided wholesale-energy procurement, fuel-cost hedging, and avoided transmission and distribution costs. It also proposed recognizing peaker-plant emissions reductions as a stackable grid service. NEEP emphasized avoided or deferred transmission and distribution costs, avoided generation, ancillary-service, and delivery-service costs, infrastructure deferral, and reliability. Ceres highlighted avoided grid-infrastructure expansion, reduced reliance on peaker plants, and improved reliability and resiliency.

**Staff Response:** Staff thanks the commenters for the comments and notes that those benefits are recognized in the Order.

Evergreen Action and EDF asked the Board to test the $60 million estimate against zonal capacity prices in the EMAAC and PSEG zones and update it after each capacity auction. It recommended measuring savings on a realized basis, setting targets on the same peak-load basis used to value savings, and evaluating cost-effectiveness at the VPP portfolio level for each EDC rather than requiring each sub-program to exceed a ratio of 1.0.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics. The Order evaluates cost-effectiveness under the RIM test at the portfolio level.

Evergreen Action and EDF, NEEP, and Vote Solar all addressed budget design. Evergreen Action and EDF asked each EDC to dedicate part of its budget to overburdened communities. Vote Solar asked the Board to increase JCP&L's budget, noting that it is smaller than ACE's although JCP&L has more than twice as many customers and faces reliability challenges. NEEP recommended a contingency budget to keep DR programs running if the VPP launch is delayed.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order establishes the goal as no less than 3% peak shave, which each EDC may exceed, and also tasks the EM&V subgroup of the PowerUp NJ Working Group to establish future goals and metrics, which could include benefits to OBC communities.

ACEEE recommended tying compensation to avoided distribution costs from specific deferrable investments, with a modest system-wide payment, targeted locational payments, and total compensation set below verified avoided cost.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics.

NJEJA proposed establishing a nine-member Independent Advisory Panel under a statutory charter that would report directly to the Board and include five community representatives, two academic researchers, and two independent industry experts, subject to term limits and conflict-of-interest protections. The panel would verify EDC and aggregator compliance with NJEJA's proposed community-ownership, customer-pass-through, and OBC revenue-allocation requirements and recommend proportional clawbacks where an entity fails to meet an equity metric for two consecutive

quarters. It would also conduct annual assessments comparing actual avoided-capacity costs, emissions reductions, and voltage-support values with the assumptions used to establish VPP incentives and recommend corresponding adjustments to base payments and equity bonuses. NJEJA further proposed that the panel publish an annual State-Level DER Impact Report covering emissions, reliability, ratepayer savings by income and geography, and workforce outcomes; oversee the financial integrity of the proposed Community Capacity Building Fund and Community Wealth Fund; recommend enforcement actions or performance bonuses; and conduct a strategic program review after five years. NJEJA proposed funding the panel through a dedicated line item equal to 0.5 percent of total VPP expenditures, subject to an annual independent audit.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order tasks the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements, and metrics. Verification of program savings will be performed by an independent evaluator retained by the Board.

**xvi. Program Implementers and Administrators**

Commenter(s) Referenced in This Summary: Ampion, Energy Solutions, Michaels Energy, and Power TakeOff

Ampion recommended that records produced by Board-licensed VPP Settlement Administrators under a common Board-approved methodology serve as the shared, auditable record for reconciling settlement calculations and resolving disputes among EDCs, aggregators, and other market participants.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics.

Energy Solutions recommended setting consistent performance metrics, measurement methods, and valuation frameworks early, before VPP portfolios provide multiple overlapping services, citing California's experience.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics, including quantifying savings from all aspects of the VPP.

Michaels Energy stated that no single existing test captures VPP value and recommended a VPP-specific test that weighs verified event performance, avoided costs by service, total program costs, participant bill effects, retention, and opt-outs, snapback, and locational value and likelihood of deferral. It asked that engineering, metering, controls integration, and commissioning count as eligible program costs in addition to hardware and performance, and that the Board publish a matrix showing which program funds each type of equipment, including thermal storage and non-electrochemical storage.

**Staff Response:** Staff acknowledges the comment and notes that, in standing up these programs, it is important to align with the existing requirements and expects that the EM&V subgroup of the PowerUp NJ Working Group will continue to work to develop a more refined test in the future.

Power TakeOff stated that persistent, passive demand reduction from EE provides distribution congestion relief that should be compensated on a pay-for-performance basis. It further stated that free-ridership concerns may be less applicable in a compensation-based market where EE actions receive separate compensation for distinct value streams under Triennium 3 and the VPP. For the long-term program, Power TakeOff stated that, if the Board permits this layered compensation, baseline modeling and AMI-based whole-building settlement will be crucial to measuring the actual demand-reduction value produced by EE measures in constrained grid locations.

**Staff Response:** Staff thanks the commenter for the comment and notes that the VPP Program both short- and long- term is designed to be technology-neutral, and any device that can respond to calls should be able to participate.

### xvii. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

Base Power stated that the savings estimate will not materialize unless EDCs reflect verified VPP savings in PJM load forecasts through Peak Shaving Adjustments (“PSA”). It asked the Board to allow negative PLC and NSPL values for exporting customers, and to count reductions from supplier-served customers toward EDC targets while tracking them separately. Base Power noted that PSA plans allow an EDC to reduce its zone’s load forecast for VPPs dispatched under a specific Temperature-

Humidity Index ("THI"). It stated that while PLC, which is set during PJM's five coincident peak hours ("5CP"), determines each load-serving entity's share of the zone's capacity obligation, PSA plans affect the overall size of the obligation assigned to the zone. Base Power recommended that the Board require the EDC to take all steps necessary to ensure that verified savings from VPPs of every category are reflected to the maximum extent possible, and as soon as possible, in the PJM load forecast, including by making interim programs compatible with PJM's THI-based dispatch where possible.

**Staff Response:** Staff thanks the commenter for the comment and agrees that savings depend on PJM reflecting verified load reductions in its load forecast. The Order does not ask the EDCs to choose between the 5CP hours and the PSA. Dispatch events must be designed to reduce peak demand, informed by a reliable forecast of PJM's capacity 5CP and transmission 1CP hours, and carried out through dispatch protocols that align with the EDC's filed PSA. Dispatch protocols should be designed to maximize ratepayer savings. Each EDC may set PSA-specific dispatch parameters, including the THI trigger, within the event limits in the Order or as justified in its filing. The Order requires each EDC to submit a PSA plan to PJM by September 10 of each year, beginning in 2027, covering the portion of its VPP Interim Program and other DR programs, excluding Block 1, that can meet PJM's PSA requirements. Each EDC must identify any resources that cannot be included and explain why. The Order also directs each EDC to develop a plan to revise its PLC calculation and reporting methods to account for negative PLCs, and to file a summary of that plan with the Board by February 12, 2027. Under the Order, a VPP provider is defined by the action it performs rather than by entity type, and third-party electricity suppliers are among the entities that may qualify.

NRG noted that if existing Triennium programs already target 2% peak reduction and move into the VPP, the 3% target may require only 1% from new resources. It recommended baselines using weather-adjusted non-event days, compensation reflecting full value, near-term funding for customer acquisition, education, and settlement systems, and hardware incentives kept separate from VPP budgets.

**Staff Response:** Staff thanks the commenters for the comment and notes the Order highlights the opportunity in leveraging existing EE resources, but also notes that only a small percentage of those are currently enlisted in a current DR program. Staff thanks the

commenters for the comments and notes that the EM&V subgroup of the Power Up Working Group to establish future goals, measurements and metrics.

### xviii. Government Agencies

Commenter(s) Referenced in This Summary: SMRSA

SMRSA asked the Board to consider critical-infrastructure and resilience benefits when evaluating cost-effectiveness and designing performance requirements, noting that wastewater plants must keep operating during outages.

**Staff Response:** Staff acknowledges the comment and notes that the benefit line items in the MFR include relevant benefits under the New Jersey Cost Test ("NJCT") and Societal Cost Test ("SCT"), and that each EDC may provide additional benefit-cost analysis with supporting documentation and justifications. Customers also retain the right to opt out of any individual event.

### xix. Financial Services

Commenter(s) Referenced in This Summary: Syntropic

Syntropic stated that a program funded by all ratepayers but open only to households that can pay several thousand dollars upfront to install equipment needed to participate in the VPP performs poorly under the RIM test. To that end, Syntropic argued that regulated financing would broaden participation without broadening who pays. It advocated for permitting regulated third-party financing subject to consumer protections and authorizing on-bill repayment for equipment loans. Syntropic further requested clarification that an entity financing equipment—but not holding customer enrollment, dispatching resources, or registering with PJM—should not be treated as a DER Aggregator. It also recommended clarifying that a separate, voluntary, and fully disclosed financing agreement between a customer and a third-party lender is not aggregator compensation or a reduction in the aggregator's required pass-through.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics. Staff also notes that the VPP Interim Program compensates grid services from devices

customers already own and does not fund hardware, in any way including loans.

**xx. Individuals and Academic Institutions**

Commenter(s) Referenced in This Summary: Bill Beren, Michael Winka, Peak+, and UDelaware

Michael Winka viewed 3% as a reasonable first-year goal, but stated that the second-year increase should be based on actual performance to exceed 3%. He also found the proposed budget a reasonable increase over the Triennium 3 DR budget of $19.5 million per year. He cautioned against using the RIM test alone, since introductory incentives can skew its results, and recommended developing VPP-specific tests through the NESP screening process inclusive of all five (5) cost effective tests.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics. The Order requires each EDC to report results under all six (6) cost tests.

UDelaware recommended evaluating cost-effectiveness by comparing capital and interconnection costs against EDC and PJM market revenues. For cost savings, UDelaware recommended including low-cost AC V2G equipment in demonstrations and the use of new standards.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements and metrics. Staff views V2G technology as a form of storage that should be compensated as such as part of the long-term tariff contemplated in the Straw Proposal.

Bill Beren asked the Board to restore funding for energy conservation and EV adoption that was reduced when RGGI funds were diverted to rate relief.

**Staff Response:** Staff thanks the commenter for the comment and notes that funding for energy conservation and EV adoption programs is outside the scope of this proceeding.

Peak+ stated that its suggested adiabatic precooling costs about $1,000 per peak kW, compared with an estimated $3,000–$5,000 per peak kW for peak-period energy.

**Staff Response:** Staff appreciates the comment and notes that the VPP Interim Program is technology-neutral and open to any DER capable of delivering dispatchable demand response on a reliable, event-driven basis. Measures that permanently reduce peak load, rather than respond to dispatch events, are generally addressed through the Board's energy efficiency programs.

# 4. Dispatch & Operations

***Straw Proposal section(s):*** *§ 2.5, § 2.6*

**Summary of Comments:** The utilities asked to keep EDC authority over dispatch, with distribution reliability taking priority, and to set technology-specific event parameters in their filings. Commenters split on the 35-event annual cap. Several technology providers found the proposed parameters workable, while many others, including most storage providers and trade associations, asked to remove the cap or raise it to 50–90 events, noting that batteries can be dispatched far more often than thermostats without affecting customers. Most trade associations and several others asked for day-ahead notice of standard events, with shorter notice and higher pay for emergency events, while Rate Counsel supported one-hour notice. Commenters also asked for dispatch targeted by location, clear triggers for grid stress events outside 5CP hours, a single statewide baseline method, and device-level measurement.

### xxi. Utilities and Utilities Association

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, RECO, and NJNG

ACE, JCP&L, PSE&G, and RECO all stated that EDCs must keep authority over dispatch for reliability, with distribution needs taking priority over wholesale or portfolio objectives. ACE called for a distribution-first dispatch hierarchy, and PSE&G stated that distribution signals should take priority over PJM signals when they conflict. RECO stated that EDCs should be able to call events when they expect a peak, not only in emergencies. NJUA asked how distribution-level objectives will be reflected when the main target is a PJM coincident peak reduction.

**Staff Response:** Staff acknowledges the comments and notes that, under the Order, the EDCs define dispatch events in relation to PJM rules and processes. Events should be informed by a forecast of PJM's 5CP hours but may also be called for distribution-level thermal constraints, local congestion, and other qualifying grid stress conditions. Dispatch protocols should be designed to maximize ratepayer savings.

Each EDC must define in its filing the conditions that qualify as a grid stress event and describe how it will prioritize dispatch to deliver the most immediate reduction in ratepayer costs. Load reduction during distribution and other grid stress events is reported separately from load reduction during the 5CP hours.

ACE, PSE&G, and RECO all opposed a single 35-event annual cap. ACE recommended technology-specific caps, with 30 to 35 events for thermostats, more for batteries, and an exception for reliability events. PSE&G stated that 35 events may be too few, recommended tiered customer options with incentives tied to event frequency, and noted that the proposed seasons do not match all PJM products. RECO recommended no fixed limit, relying instead on performance requirements and operational need.

**Staff Response:** Staff thanks the commenters for the comments and notes that the Order allows the EDCs to propose parameters and metrics outside the recommend caps and parameters with a narrative for why such deviations would be necessary. Staff recognizes that the Interim program is designed as a bridge to a long-term program and is an opportunity to learn how to best design such a program.

ACE, PSE&G, and RECO all recommended technology-specific dispatch parameters that EDCs can propose, using the Straw Proposal's parameters as a starting point subject to Board approval. RECO also asked for flexibility on event duration given differences in DER capabilities.

**Staff Response:** Staff thanks the commenters for the comments and notes that the Order allows the EDCs to propose parameters and metrics outside the recommend caps and parameters with a narrative for why such deviations would be necessary. Staff recognizes that the Interim program is designed as a bridge to a long-term program and is an opportunity to learn how to best design such a program. Staff also notes that the EM&V subgroup of the PowerUp NJ Working Group will help establish future goals, measurements and metrics and additional subgroups may be formed to collaborate on future dispatch parameters.

RECO recommended that EDCs have the ability, but not the obligation, to call test events each year, noting that test events at its affiliate in New York reduced underperforming systems from 82 to two within a year.

**Staff Response:** Staff thanks the commenters for the comments and notes that the Order allows the EDCs to propose parameters and

metrics outside the recommend caps and parameters with a narrative for why such deviations would be necessary. Staff recognizes that the VPP Interim Program is designed as a bridge to a long-term program and is an opportunity to learn how to best design such a program. Staff also notes that test calls to confirm system readiness do not count toward the thirty-five (35)-event annual cap.

PSE&G stated that aggregator access to AMI data should follow the approved AMI data access plans and raised concerns about the proposed 24-hour data threshold.

**Staff Response:** At this time, Staff expects that the EDCs adhere to the Board's adopted requirements of the AMI data access rules and any subsequent Order establishing a process for Board staff to approve third parties as eligible to be authorized by customers to access AMI data. The AMI data access rules were adopted according to a rulemaking schedule initiated before this proceeding and represents a balance needed to prevent unnecessary investments and reflect uncertainty in energy market requirements for VPP programs at the time of drafting. Board staff continues to monitor the market and review if there is a need to propose an update to the rules. Staff will continue to assess actual operational and reporting requirements for VPP participation in wholesale markets and weigh the options to provide settlement data that reflect the most cost beneficial and technologically feasible means of doing so. The Interim program proposal does not contemplate that modification of the existing AMI data access framework is necessary for successful implementation and staff does not presuppose that validated AMI data is necessary for successful implementation of the long-term program.

NJUA stated that the VPP framework should complement, not compete with, the existing PJM wholesale market, and that the Interim Program should build on existing PJM participation without creating incentives that reduce it. It stated that customers should be able to provide distinct distribution and PJM services without duplicate compensation, and that participation in the State program should not reduce their ability to participate in PJM programs, or vice versa. NJUA recommended that baseline, compensation, and EM&V methods recognize that customers already in wholesale markets may provide incremental distribution-level benefits that warrant separate evaluation, and that EM&V remain flexible enough to account for participation across multiple markets.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Straw and Order indicates that unlocking these multiple compensation streams while guarding against double payment is both a short and long-term goal.

NJNG asked the Board to evaluate performance during multi-hour and consecutive-day events, noting that gas-fired DERs can run longer than batteries. It stated that natural gas DERs can provide extended-duration and consecutive-day dispatch supported by existing gas infrastructure, and that gigawatts of capacity from existing natural gas emergency backup generators sit idle during peak electric loads. NJNG stated that leveraging this existing fleet of customer-owned backup generators and other BTM resources could expand VPP capacity while minimizing the need for new infrastructure investment. It also asked that event parameters be coordinated with the EDCs, NJDEP, EPA, and emergency authorities so resources are not given dispatch obligations they cannot legally meet, such as run-hour or emissions limits.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order designs the VPP Interim Program as a clean energy, technology-neutral program open to DERs capable of delivering dispatchable demand reduction on a reliable, event-driven basis, and directs the EDCs to build on existing grid infrastructure and customer-owned DER assets**.** The Order sets a maximum event duration of three (3) hours, and each EDC must define in its filing the conditions that qualify as a grid stress event.

### xxii. Division of Rate Counsel

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel found the proposed event duration and number of events reasonable. It recommended reducing minimum notice to one hour with best efforts to give more, allowing opt-outs with reduced pay, keeping dispatch parameters largely consistent across EDCs, and requiring EDCs to show the forecast behind each dispatch. It also recommended limiting EDC overrides to documented emergencies and publicly reporting each override and its reason.

**Staff Response:** Staff appreciates the comments and notes that the Order sets common dispatch parameters for all EDCs: a maximum event duration of three (3) hours; a suggested cap of twenty (20) summer events, ten (10) winter events, and five (5) shoulder-season

events; and at least twenty-one (21) hours of notice for standard events and thirty (30) minutes for grid stress events. Customers may opt out of any event, although frequent opt-outs may affect incentive payments. Each EDC must define in its filing the conditions that qualify as a grid stress event and how it will decide in real time to call one, and must provide event-level dispatch reports to the Board.

**xxiii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, EnergyHub, ev.energy, Foley, Honeywell, Koolbridge, Logical Buildings, Lunar, ModernElectric, Piclo, Recurve, Renew Home, RExChain, Solar Landscape, Soltage, Steffes, SunStrong, Tesla, Tri-State, Turtle & Hughes, Uplight, UtilityAPI, Voltus, and WeaveGrid

Logical Buildings, Lunar, ModernElectric, Piclo, and Solar Landscape found the proposed event parameters workable, including the thirty-five (35) event cap. Solar Landscape recommended a 3.5-hour maximum event duration, seasonal dispatch limits, and a defined annual cap, explaining that standard four-hour batteries may preserve reserve capacity. It considered thirty-five (35) events a reasonable starting point for the Interim Program and recommended allowing an EDC to propose additional events only where it demonstrates incremental ratepayer value and provides incremental compensation reflecting the additional performance, availability, cycling, and opportunity-cost obligations. Solar Landscape also noted that emergency reliability events may warrant separate treatment. Logical Buildings and ModernElectric asked that test and emergency events not count toward the cap, and Logical Buildings asked for day-ahead advisories for complex buildings. Voltus supported the Straw Proposal's 4-hour maximum event duration, its 80% minimum performance threshold applied to the aggregation rather than each device, and its cap of up to 35 events per year (20 summer, 10 winter, and up to 5 in shoulder seasons).

**Staff Response:** Staff acknowledges the comments and notes that the Order sets a maximum event duration of three (3) hours, suggests a limit of thirty-five (35) events per year, and at least twenty-one (21) hours of notice for standard events. Test calls to confirm system readiness do not count toward the annual cap. An EDC may propose additional dispatch opportunities where supported by operational need, participant capability, customer protections, and a demonstrated

incremental ratepayer benefit. Staff also notes that specific storage based requirements are addressed in the Block 1 section of the Order.

EnergyHub, ev.energy, Renew Home, Tesla, and Uplight all opposed a fixed annual event cap. Tesla recommended about 60 events, with dispatch based on Temperature-Humidity Index triggers rather than 5CP. EnergyHub recommended framing limits in hours by device type, such as up to 80 hours per season for thermostats and two hundred for batteries and EVs, with 2-3 hours as the best event length. Renew Home recommended no cap and flexible one- to four-hour windows, noting its customers shift load for 15 minutes to eight hours. ev.energy recommended no cap unless opt-outs become common, and room for daily load shifting. Uplight recommended allowing EDCs to offer different customer participation options, including tiers with different expected event frequencies and corresponding incentive levels.

**Staff Response:** Staff thanks the commenters for the comments and notes that the Order sets a suggested annual cap of thirty-five (35) events, while allowing an EDC to propose additional or shorter-notice dispatch opportunities where supported by operational need, participant capability, customer protections, and a demonstrated incremental ratepayer benefit. Each EDC may also set PSA-specific dispatch parameters, including a temperature-humidity index trigger. Incentive structures are proposed in each EDC's filing, subject to the approval of the Board.

Calibrant and Voltus both questioned basing dispatch on 5CP hours. Voltus stated that customers already have incentives to reduce load during 5CP hours and that 5CP dispatch would block dual participation in PJM's Load Management program, and recommended triggers based on forecast supply shortfalls in a territory or on constrained feeders. Calibrant asked the Board to define what counts as a grid stress event outside 5CP hours.

**Staff Response:** Staff acknowledges the comments and notes that dispatch events under the Order are informed by a forecast of PJM's 5CP hours but are not limited to those hours. The Order intends to design a program that provides savings at the capacity, distribution and transmission level. Events may also be called for distribution-level thermal constraints, local congestion, and other qualifying grid stress conditions, and each EDC must define in its filing the conditions that qualify as a grid stress event. Where an enrolled customer also participates in a PJM program, each EDC must propose how the

associated revenue streams will be treated and describe the safeguards that prevent double compensation.

ModernElectric, Piclo, Solar Landscape, Soltage, Tri-State, and WeaveGrid addressed geographically targeted or distribution-aware dispatch. ModernElectric asked EDCs to define dispatch zones and state each event's location, purpose, requested kW, duration, notice, and measurement method. Piclo characterized geographic-targeting capability, including segmentation by locational node, technology type, and response capability, as essential and recommended making it a firm MFR requirement. Piclo further stated that locational dispatch is necessary for the Interim Program to demonstrate the distribution-level value supporting the long-term tariff's locational compensation structure Solar Landscape supported segmenting resources by locational node, technology, and response capability so EDCs could call resources capable of addressing a specific peak, local distribution constraint, or infrastructure-deferral opportunity rather than dispatching the entire portfolio indiscriminately. Soltage recommended the EDCs define a clear scheduled dispatch window to all distribution-level assets to ensure localized system needs are met, while Tri-State recommended that utility DERMS map customers to circuits. WeaveGrid recommended using device-level telemetry and active orchestration to manage charging at the substation, feeder, and secondary-transformer levels. It separately cautioned that unmanaged or highly synchronized responses to time-of-use price signals could create secondary or "snapback" peaks and may fail to respect local distribution constraints.

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Order requires each EDC's dispatch platform to segment enrolled resources by locational node, technology type, and response capability, so that only resources providing locational value are dispatched for a specific event. Each EDC must describe this capability in its filing, explain how it will use VPP grid services in distribution planning and operations, including coordination with its Proactive System Upgrade Plan (See BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*) filing, and report enrolled devices and kW by ZIP code and, where identified, on constrained circuits.

Koolbridge and Recurve both asked for a single statewide baseline and measurement standard in the MFRs rather than separate methods for each EDC, noting that results differ materially by method. Calibrant asked for

dedicated sub-metering of storage, since batteries cycling for demand-charge management distort facility baselines. ModernElectric, Renew Home, Voltus supported device-level telemetry for measuring event performance, with AMI serving as a check. WeaveGrid also supported device-level telemetry but described it as a parallel measurement pathway and characterized AMI as an important source for measurement, verification, settlement, and program evaluation rather than the sole source of performance data.

**Staff Response:** Staff acknowledges the comments and notes that each EDC must propose its customer baseline methodology in its filing, including the treatment of accounts with on-site generation or storage. The Order directs the EM&V subgroup of the PowerUp NJ Working Group to recommend shared EM&V metrics and methodology for Staff approval within sixty (60) days of Board approval of the EDC petitions, which will support a consistent approach across the EDCs. Until then, each EDC uses the methodology approved in its petition.

EnergyHub, Renew Home, and Tri-State all supported easy customer opt-outs, with pay reduced accordingly. Tri-State reported that allowing two penalty-free opt-outs helped enrollment and kept opt-out rates below 3%. Renew Home distinguished notice to customers from signals to devices. Calibrant asked that opt-out rights and penalties apply to the entity controlling the battery, such as the owner-operator under an energy services agreement, rather than the host customer.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the Order preserves customer opt-out rights for any individual event, with the understanding that frequent opt-outs may affect customer incentive payments. Each EDC must also report customer opt-out rates as part of its performance indicators.

Honeywell recommended approved event rules covering who may call events, the dispatch basis, notice, duration, operating limits, and customer override rights, and stated that equipment safety controls and lawful EDC emergency instructions must take priority.

**Staff Response:** Staff acknowledges the comment and notes that the Order sets default event rules for the VPP Interim Program, including event duration, frequency, notice, and customer opt-out rights. Each EDC must define in its filing the conditions that qualify as a grid stress event, how it will decide in real time to call one, and how its dispatch protocol conforms to the Order or why any deviation is justified.

Lunar stated that each enrolled device should have a single aggregator sending dispatch signals at any time, since conflicting signals can make devices respond incorrectly or break limits such as battery reserve floors, and that switching aggregators should happen only after a complete transition.

**Staff Response:** Staff thanks the commenter for the comment and agrees that conflicting dispatch signals should be avoided. In the Order, each EDC must describe in its filing the roles of the utility, any implementation contractor, and third-party aggregators, along with its enrollment and dispatch processes. The DER registry and aggregator code of conduct anticipated in the Order, to be developed through the PowerUp NJ Working Group, can also address enrollment and aggregator switching.

Steffes asked the Board to allow scheduled, forecast-based pre-charging and load shaping, such as overnight charging of thermal storage, in addition to real-time interruption, and to include winter peak dispatch.

**Staff Response:** Staff appreciates the comment and notes that the Order includes up to ten (10) winter events per season, from December 1 through the last day of February. An EDC may also propose additional dispatch opportunities where supported by operational need, participant capability, customer protections, and a demonstrated incremental ratepayer benefit.

Koolbridge stated that events of four to seven hours cause opt-outs when devices are simply turned off, and that panel-level source-switching to on-site solar and batteries keeps household power on while reducing meter load.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order sets a maximum event duration of three hours. The technology-neutral design allows intelligent electrical panels and other new technologies to participate where they can deliver verified demand reduction.

RExChain recommended offering two-hour and four-hour increments, rather than a single undifferentiated "up to 4 hours" ceiling, with a corresponding adjustable compensation factor for each commitment tier.

**Staff Response:** Staff thanks the commenter for their feedback and notes that the Order sets a maximum event duration of three hours.

Each EDC proposes its incentive structure in its filing and may propose dispatch parameters that differ from the Order with justification.

Foley recommended that a minimum share of enrolled VPP capacity be able to perform during outages, and that performance be evaluated event by event as well as by season.

**Staff Response:** Staff acknowledges the comment and notes that the VPP Interim Program is designed to reduce peak demand during dispatch events and does not include an outage-performance requirement. Attachment A requires event-level reporting of MW delivered versus MW committed, as well as post-season and annual performance reporting.

DCO recommended defining dispatchable demand reduction for CHP microgrids as metered net demand reduction at the customer meter during designated periods or events.

**Staff Response:** Staff thanks the commenter for their feedback and notes that the framework envisioned in the straw was designed as a clean energy, technology-neutral program. Staffalso notes that the Straw indicates that the VPP Interim Program is just the first step in building out a robust market for storage and grid services.

SunStrong noted some administrators of California's Emergency Load Reduction Program use an opt-out enrollment pathway. Under that program's Service Provider construct, the aggregator signs an agreement directly with the utility, and its customers do not need to sign the utility's per-customer enrollment form because the aggregator's own customer agreement includes the authorization. The Service Provider is responsible for notifying customers of events, passing through compensation, and complying with program cybersecurity and privacy reviews.

**Staff Response:** Staff thanks the commenter for their feedback and notes that each EDC must describe in its filing the roles of the utility, any implementation contractor, third-party aggregators, and third-party suppliers, along with its enrollment processes and the service delivery pathways offered to customers.

UtilityAPI recommended that the Board direct EDCs to implement Green Button Connect-certified data-exchange platforms providing authorized third parties standardized electronic access to actual interval data needed for enrollment and settlement. Turtle & Hughes separately recommended a clear and predictable participation pathway, including timely access to

interval load data, understandable program economics, transparent eligibility requirements, standardized application materials, defined review timelines, and clear performance and settlement rules.

**Staff Response:** Staff thanks the commenters for their feedback and notes that each EDC must describe in its filing the process and timeframe by which it will make customer data available to a customer's authorized aggregator. Each EDC must also propose the cadence for event-level reports, which include MW delivered versus MW committed and settlement data. Data access remains subject to the Board's AMI data access rules at N.J.A.C. 14:5-10.

**xxiv. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, SEIA/CCSA/NJSEC, Smart Thermostat Coalition, and VGIC

Advanced Energy United, the BTM Coalition, EEA-NJ, SEIA/CCSA/NJSEC, and VGIC all supported day-ahead notice for standard events, instead of the proposed two hours. SEIA/CCSA/NJSEC stated that resources such as energy storage may require several hours to charge and that two-hour notice would not provide sufficient time to recharge, particularly when operating under time-of-use rates, net-metering rates, or flexible-interconnection requirements. The BTM Coalition separately identified day-ahead notice for normal events and same-day notice for emergencies as a best-practice program structure. EEA-NJ stated that larger C&I customers need more lead time. VGIC noted that PJM 5CP forecasts are available up to a week ahead and asked that EDCs share them with all participants. Advanced Energy United recommended a shorter 30-minute notice for smart thermostats.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order calls for a three (3)-hour maximum events duration and at least twenty-one (21) hours of notice for standard events. Staff determined that dispatch protocols should be consistent for the first iteration of the program.

Advanced Energy United, EEA-NJ, and SEIA/CCSA/NJSEC all supported separate rules for emergency events. Advanced Energy United recommended distinguishing emergency from non-emergency events, allowing less than two hours' notice for emergency events, and treating weather-driven and reliability-triggered dispatch as qualifying grid-stress

conditions. SEIA/CCSA/NJSEC recommended at least two hours of same-day notice for emergencies, and EEA-NJ recommended higher pay for short-notice and emergency events.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order calls for at least twenty-one (21) hours of notice for standard events and thirty (30) minutes for grid stress events. Staff notes that the EDCs can propose incentive levels and must define grid stress events in their filings.

Advanced Energy United, the BTM Coalition, SEIA/CCSA/NJSEC, and the Smart Thermostat Coalition recommended increasing or removing the 35-event cap, although their recommendations differed by resource type. Advanced Energy United and SEIA/CCSA/NJSEC recommended allowing 60 to 90 annual events for residential resources or BTM storage, while the BTM Coalition recommended 50 to 70 annual events. SEIA/CCSA/NJSEC stated that storage can generally respond more frequently than thermostats or EV chargers without affecting customer comfort and recommended both a minimum of 35 events and limits tailored to the participating resource. The Smart Thermostat Coalition recommended removing seasonal and annual caps for legacy thermostat programs while retaining duration and notice requirements and allowing more frequent events, subject to model-specific daily limits, for newer participation models using smaller temperature adjustments. EEA-NJ supported retaining an annual cap but recommended higher compensation for higher event obligations and allowing customers to identify, in advance, a limited number of dates on which they would be unavailable.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order sets a suggested cap of thirty-five (35) events per year, but an EDC may propose additional dispatch opportunities where supported by operational need, participant capability, customer protections, and a demonstrated incremental ratepayer benefit. The EDCs can also propose incentive levels in their filings. The Order also provides customers opt-out rights for any individual event. Residential and small commercial BTM storage is compensated through Block 1, whose preliminary event parameters will be refined through the MFR process, and EDCs may propose additional dispatch opportunities there as well.

Advanced Energy United, the BTM Coalition, and the Smart Thermostat Coalition all supported a four-hour maximum event duration, with Advanced

Energy United applying it per day for thermostats. The BTM Coalition recommended that failure to perform reduce pay without added penalties.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Order calls for a three (3)-hour maximum events duration.

Advanced Energy United, the BTM Coalition, ChargEVC, and the Smart Thermostat Coalition all asked the Board to accept device-level data for measuring event performance. The BTM Coalition recommended device data for compensation, and suggested that AMI could be used for program evaluation and PJM settlement. Advanced Energy United supported converting thermostat runtime to kW using weather-adjusted assumptions. ChargEVC stated that M&V should not require a second utility meter and that measurement for transportable storage should follow the resource.

**Staff Response:** Staff thanks the commenters for their comments and notes that the Order allows for flexibility, as each EDC proposes its baseline and measurement methodology in its filing and the EM&V subgroup of the PowerUp NJ Working Group will recommend shared EM&V metrics and methodology.

**xxv. Advocacy Groups**

Commenter(s) Referenced in This Summary: Evergreen Action and EDF, NJECN, and Vote Solar

Evergreen Action and EDF and Vote Solar both asked for more dispatch events. Evergreen Action and EDF recommended removing or raising the cap and treating the seasonal counts as a minimum EDC dispatch obligation, with annual reports on available capacity that was not dispatched. Vote Solar recommended up to 60 summer and 20 winter events for batteries and asked that EDC EM&V include device-level metering and telemetry.

**Staff Response:** Staff thanks the commenters for the comment and notes the Order allows EDCs to propose additional calls with a narrative justifying the increase.

NJECN recommended shorter events, such as two groups of customers for two hours each rather than one four-hour event, and more than two hours of notice whenever possible, citing a participant who sometimes had too little notice to opt out.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order calls for a three (3)-hour maximum event duration and at least twenty-one (21) hours of notice for standard events, but permits EDCs to provide more granular requirements.

### xxvi. Program Implementers and Administrators

Commenter(s) Referenced in This Summary: Energy Solutions and Michaels Energy

Energy Solutions recommended that utility filings set clear dispatch notice requirements, baseline methods, and event performance methods for the Interim Program.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order details dispatch requirements and requires each EDC to propose its baseline and event performance methods in its filing.

Michaels Energy recommended treating four (4) hours as a default rather than a cap, since thermal storage can support events of eight to ten hours or more, or several events a day. It asked that baselines exclude pre-charging hours and days when a resource prepared for a canceled event. Michaels Energy also proposed that the MFR provide that post-event snapback and net energy be measured, and that documented safety, food-quality, and personnel overrides carry no penalty beyond lost performance payment.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order calls for a three (3)-hour maximum event duration. Each EDC must propose its baseline methodology in its filing, including how it accounts for load changes caused by other factors, so that only reductions caused by VPP dispatch are counted.

### xxvii. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

NRG recommended day-ahead notice for C&I customers, higher pay for emergency events with 10-minute notice, and shortening the maximum event by one hour, since storage events typically last two to three hours. It supported a reasonable annual cap that allows extra emergency events, and baselines using weather-adjusted non-event days with a same-day adjustment.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order calls for at least twenty-one (21) hours of notice for standard events and thirty (30) minutes for grid stress events. The Order caps dispatch events at thirty-five (35) per calendar year, with no more than twenty (20) in the summer season and ten (10) in the winter season, and test calls do not count toward the cap. Staff views this cap as reasonable because twenty (20) summer events leave room to cover the summer coincident peak hours while limiting the burden on participants. The cap is also flexible: events may be called outside the seasonal windows within the annual total, and an EDC may propose additional or shorter-notice dispatch opportunities where supported by operational need, participant capability, customer protections, and a demonstrated incremental ratepayer benefit. With the consideration of the comment, the Order also shortens the maximum event duration from four (4) hours in the Straw Proposal to three (3) hours.

Base Power stated that third-party suppliers need dispatch flexibility and should not be required to enroll all flexible load or give up exclusive dispatch rights.

**Staff Response:** Staff thanks the commenter for the comment. Under the Order, a VPP provider is defined by the function it performs rather than by entity type, so a third-party supplier that aggregates and dispatches customer DERs may participate as a VPP provider. The Order does not require a VPP provider to enroll all of its flexible load. Under the third-party aggregator pathway, the VPP provider manages the customer's devices through systems that interface with the EDC's dispatch infrastructure, and each EDC must describe in its filing the roles of third-party aggregators and third-party suppliers.

### xxviii. Government Agencies

Commenter(s) Referenced in This Summary: SMRSA

SMRSA asked that CHP demand reduction and net exports be measured and settled separately, and that response beyond zero customer demand be credited. It gave the example of its facility increasing CHP output during an event to go from importing 170 kW from the grid to net exporting 100 kW, a total change of 270 kW at the meter. It stated that a method that stops measuring at zero demand would credit only the 170 kW. It also asked that baselines not penalize early adopters whose continuously running CHP already lowers their metered demand.

**Staff Response:** Staff thanks the commenter for their feedback and notes that the Straw Proposal indicated that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The MFR requires each EDC must propose its baseline methodology, including the treatment of accounts with on-site generation or storage.

### xxix. Financial Services

Commenter(s) Referenced in This Summary: Syntropic

Syntropic supported paying for verified, delivered performance confirmed by meter and dispatch records.

**Staff Response:** Staff thanks commenter for their support and notes that the short- and long-term VPP programs are designed to provide compensation for the services provided.

### xxx. Individuals and Academic Institutions

Commenter(s) Referenced in This Summary: Michael Winka and UDelaware

Michael Winka supported the proposed dispatch protocols but asked the Board to provide public education on event warnings to reduce opt-outs, and to use opt-out rates as a performance metric for EDCs and aggregators.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the EDC filings must include details on dispatch mechanisms including opt-outs, and must report customer opt-out rates as a performance indicator. The Board, aggregators, and EDCs will each have a role in providing education on dispatch mechanisms.

UDelaware recommended that a VPP providing PJM services still be required to accept EDC dispatch requests in emergency conditions or to preserve reliable service, as FERC Order No. 2222 requires, and stated that the Board could reasonably require the same of VPPs providing only EDC services. To avoid overuse, it suggested a limit of about 80 hours of requests per year, and that the Board or the VPP be able to ask the EDC for evidence of a grid emergency. UDelaware further recommended requiring the VPP operator to respond to EDC dispatch requests rather than permitting the EDC to control individual DERs directly, reasoning that

experienced V2G VPP operators possess the driving data and algorithms needed to dispatch EV subgroups without compromising anticipated driving needs or battery life. It also recommended using EVSE meters for PJM services and premises AMI meters for EDC services.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the EDC filings must include details on dispatch mechanisms including opt-outs and define grid stress events. The Board, aggregators, and EDCs will each have role in providing education on dispatch mechanisms. The Order includes definitions of the role of VPP Providers. The Order caps dispatch events at three (3) hours each and thirty-five (35) per calendar year, and each EDC must describe in its filing how it will decide in real time to call a grid stress event.

# 5. EDC-Aggregator Relationships and Interim Filings

***Straw Proposal section(s):*** *§ 2.2(i), § 2.8, § 2.9*, § 2.4 (Stakeholder Comment No. 6)

**Summary of Comments:** Commenters split on how much of the Interim Program the EDCs should run. The utilities, Rate Counsel, and several technology providers supported keeping dispatch, AMI data, and PJM communication with the EDC or its implementation contractor, while many aggregators, trade associations, and advocacy groups asked to move customer-facing functions to aggregators sooner. Many commenters asked for a more open aggregator pathway, such as a walk-up tariff, open enrollment through edge DERMS, or a shared or scheduled solicitation, and Voltus asked the Board to strike the Triennium 2 grandfather provision. Most commenters on the bifurcated start supported having new customers enroll under the VPP framework. Aggregators and developers asked for minimum contract terms and longer revenue certainty, while ACE, PSE&G, and RECO asked for flexible contracting. On the MFRs, the utilities asked to narrow requirements and reduce reporting, while other commenters asked for standardized statewide templates, onboarding rules, and added disclosures.

### xxxi. Utilities and Utilities Association

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, and RECO

ACE, JCP&L, PSE&G, and RECO all stated that the EDCs should keep key operational authority during the Interim Program. ACE and PSE&G supported keeping dispatch, AMI data provisioning, PJM communication, and marketing and enrollment with the EDC or its implementation contractor for the full Interim Program, with PSE&G citing a seamless experience for existing Triennium 2 participants. ACE stated that functions

should move to aggregators only after standards, systems, and accountability are in place, and asked for continuity-of-service rules if an aggregator withdraws, becomes insolvent, or fails to perform. RECO stated that dispatch should remain primarily with the EDC, including events for expected local or system peaks, while aggregators continue to support customer acquisition and enrollment. JCP&L asked the Board to confirm EDC authority to override, curtail, or limit resources for reliability, and to make aggregators responsible for enrollment, consent, device coordination, performance, telemetry, cybersecurity, customer support, and PJM and FERC obligations under a Board-administered qualification framework. NJUA asked that EDCs keep visibility into and authority over DER dispatch, including the ability to monitor and, where necessary, override third-party dispatch decisions. NJUA stated that this authority should apply not only during emergencies but also during abnormal system conditions, local reliability events, planned or unplanned outages, and other conditions where DER dispatch could materially affect distribution operations.

**Staff Response:** The interim program is an EDC administered program and the Order provides details on dispatch, marketing, aggregation and enrollments. Under the Order, dispatch events are called during periods of high grid stress as determined by the EDC in coordination with PJM. Staff notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The PowerUp NJ Working Group will also work with stakeholders to continue to refine protocols consistently across EDCs.

ACE, PSE&G, and RECO differed on the Aggregator Solicitation Plan. ACE supported it as a meaningful step toward customer choice and asked for transparent evaluation criteria and consistent statewide requirements. PSE&G stated that the plan does not provide true customer choice, because settlement at the AMI meter forces a customer with a thermostat in the EDC program and a battery with an OEM aggregator to choose one. PSE&G also stated that EDCs cannot forecast how many aggregators will enter, and asked that the plan be removed from the MFRs, with EDCs instead updating Staff through the working group. RECO stated that a new solicitation would add administrative burden without matching benefits, and asked that EDCs be allowed to keep existing aggregator relationships. It noted that aligning its New Jersey processes with its New York programs saves costs.

**Staff Response:** Staff notes that the Order details an EDC-administered program that builds upon the existing DR programs. The Order requires the EDCs to offer customer choice through at least two

(2) service delivery pathways and suggests that EDCs propose solutions to some of the conflicts described in the comments as part of their filings. Staff believes that existing aggregators can be part of offering that customer choice. Under the Order, aggregator and OEM relationships established under an EDC's existing Triennium 2 DR programs may continue without a new competitive solicitation.

ACE, PSE&G, and RECO all addressed the bifurcated program start. ACE found it feasible and recommended that customers enrolling after VPP approval start under the VPP, while existing Triennium customers move over time, with aligned incentives and clear customer disclosures. PSE&G supported continuing current DR and VPP programs under Triennium 2.5 until the VPP programs are approved and the EDCs are ready to operate. RECO stated that feasibility depends on the timing of Board approval, since some programs, such as its CSRP, have fixed enrollment periods, and that enrollment may need to start in 2028 if approval comes too late for summer 2027.

**Staff Response:** Staff notes that the Order requires EDCs to outline transition plans from the Triennium programs to the VPP Interim Program as part of their filings. The Order also directs the EDCs to continue their Triennium 2 DR programs without interruption until the VPP Interim Programs are operational.

ACE, PSE&G, and RECO all asked for flexible contracting rather than fixed terms or MW commitments. ACE supported negotiated terms instead of minimum contract durations, and phasing out Interim compensation once resources move to the long-term tariff, with a limited transition period. PSE&G asked to replace the contracting and performance-based compensation requirement with a flexible approach, stating that residential customers do not understand capacity commitments and that a fixed incentive per device is clearer. RECO noted that it does not require contracted MW commitments today and stated that it is premature to set long-term contract structures or transition timelines before the Interim Program is evaluated.

**Staff Response:** The Order provides the EDCs flexibility to propose structures that make sense in their territory with the goal of achieving a MW peak shave. However, all EDC-aggregator contracts must be performance-based and include a contracted MW commitment. The Order also requires a transition plan from the Triennium to the VPP Interim Program and then from the VPP Interim Program to the long-term tariff.

ACE, JCP&L, NJUA, and PSE&G all asked the Board to narrow or clarify the MFRs. JCP&L asked that initial filings rely on existing program experience and defer DERA qualification standards, cybersecurity, telemetry and data-sharing protocols, DERMS functions, IT/OT integration, and detailed EM&V methods to later compliance filings. PSE&G asked to remove the Aggregator Solicitation Plan and Planning and Operations Integration MFRs as premature, to consolidate the Peak Demand Reduction and Cost Savings Target MFRs, which it said duplicate the forecast and cost-effectiveness MFRs, and to drop items such as the number of eligible customer accounts. NJUA asked the Board to resolve baseline treatment, interaction with wholesale markets, and performance evaluation before utilities file. ACE asked for a standardized template, flexibility to update filings, and confidential treatment of sensitive operational, customer, and contract data.

**Staff Response:** Staff notes that the Order provides details on the protocols and requirements of the program. The program is intended to build upon the demand response programs already begun in the Triennium. Staff recognizes that the Interim VPP Interim Program is a bridge to a long-term tariff to provide compensation for grid services, which means that it is also an opportunity to gather data about how to best design future programs.

ACE, NJUA, and RECO all asked for less frequent reporting than the proposed quarterly and event-level reports. NJUA recommended reporting after each capability period, using data already collected through existing reporting, and noted that DERs may be dispatched daily in peak seasons. RECO recommended one annual public report after the summer capability period, with aggregator-specific data kept confidential. ACE agreed that event metrics matter but supported semi-annual and annual reporting.

**Staff Response:** Staff recognizes that developing programs for nascent markets will require refinement. The best way to determine what changes are needed is to gather data on uptake and response, and the Order's reporting requirements reflect that.

### xxxii. Division of Rate Counsel

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel supported advancing programs from the Triennium without waiting for the VPP rollout, to capture savings sooner, and recommended moving all similar DR and VPP programs under the VPP Program.

**Staff Response:** The Board has directed DR programs to continue under the Triennium until such time as the VPP Interim Program are operational, at which point those programs should be administered and recovered as directed in this Order.

Rate Counsel stated that EDCs or their contractors should keep dispatch, AMI provisioning, and PJM communication during the Interim Program, while aggregators begin marketing and enrollment. It recommended solicitations that allow multiple aggregators per EDC, resource type, and customer segment, with EDC-offered programs competing against aggregator proposals on cost and effectiveness.

**Staff Response:** The Order calls for a design that encourages an open market as part of the long-term program and calls for at least two (2) service delivery pathways for customers during the VPP Interim Program.

Rate Counsel agreed that aggregators need revenue certainty and stated that the two-year Interim Program may be too short, so contracts should anticipate the transition and, where possible, extend beyond it. It withheld judgment on transition plans until the EDCs file them, and recommended that transition costs be separately identified, shown to be incremental, subject to prudence review, and paid by those who cause them.

**Staff Response:** Staff notes that the Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff. The current program lasts through September 30, 2029 with a Midterm Review that will evaluate the first year of the program, and help determine next steps as the long-term tariff is developed.

Rate Counsel found the proposed MFR components reasonable but had reservations about the Transition Strategy given PJM market uncertainty. It asked for a uniform statewide analytical template for all EDC filings, with any deviation justified.

**Staff Response:** Staff notes that the Order lays out the evaluation mechanisms for the programs and anticipates that the EM&V Subgroup of the PowerUp NJ Working Group will work to develop a more refined test in the future. The Order and attachment also specifies common benefit and cost line items so that the EDC filings are computed on the same basis.

**xxxiii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, Edge Zero, Edgeli, Electrify America, EnergyHub, ev.energy, Foley, Honeywell, Logical Buildings, ModernElectric, Nexamp, NJRCEV, Oracle, Piclo, Renew Home, RExChain, Solar Landscape, SunStrong, Tesla, Tri-State, Turtle & Hughes, Uplight, Virtual Peaker, Voltus, and WeaveGrid

ev.energy, Piclo, and Solar Landscape all supported having customers who enroll after program approval start under the VPP framework rather than the Triennium. Solar Landscape asked for a clear cutover date for each transitioning program, continued customer and aggregator relationships, and no overlapping pay for the same service. EnergyHub and Renew Home cautioned that two parallel enrollment tracks could confuse customers. Renew Home found the bifurcated start workable if existing customers see no change and do not have to re-enroll, and recommended moving existing Triennium-funded programs to VPP funding in July 2027, with new customers enrolling under the existing structure where a program continues mostly unchanged. EnergyHub asked for simple enrollment and easy-to-understand incentives during any transition.

> **Staff Response:** Staff thanks Commenters for the comments and notes that the EDC-run VPP Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. The VPP Interim Program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff.

EnergyHub, Honeywell, Renew Home, and Uplight all supported keeping core program functions with the EDC or its implementation contractor during the Interim Program. EnergyHub stated that this mirrors the Triennium 2 DR model and is the fastest path to peak reductions, with each EDC deciding whether to perform functions in-house or through a contractor. Renew Home stated that reassigning functions mid-program could disrupt customers and take capacity offline, and asked that OEMs and aggregators enroll devices through utility-direct or EDC-DERMS interfaces. Uplight recommended that the Phase 1 operating model remain consistent throughout Phase 1, with the EDC or its implementation contractor retaining the principal program administration and coordination

functions identified by Staff, an orderly migration of functions in Phase 2, and a direct EDC pathway alongside aggregators in the long term. Oracle supported EDC administration of the Interim Program and open, non-discriminatory access for qualified third-party aggregators in the long-term framework. It asked the Board to preserve a utility-administered pathway in both phases, and to clarify that a utility may administer behavioral programs and other load-flexibility offerings directly, may engage qualified implementation partners, and may coordinate those offerings with third-party aggregator participation.

Honeywell recommended that each EDC filing include a responsibility matrix identifying the accountable, performing, and supporting parties; authoritative data source; required interfaces and evidence; decision rights; and escalation path for every material function. Separately, Honeywell recommended that interim contracts provide sufficient clarity regarding scope, term, and expected revenue to support implementation and customer acquisition while preserving an orderly transition to the long-term tariff. It recommended that those contracts define scope and performance obligations; interface, testing, service-level, and data-quality requirements; cybersecurity and change-control responsibilities; and transition and knowledge-transfer obligations. Honeywell further recommended basing contractual acceptance on documented test evidence for the assigned function rather than software installation or interface connection alone.

> **Staff Response:** Staff thanks commenters for the comments and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The Order allows each EDC to deliver its program through EDC staff and contracted implementation contractors. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff.

ev.energy, ModernElectric, Solar Landscape, and Tesla all supported giving aggregators customer-facing functions during the Interim Program. ev.energy recommended shifting dispatch, AMI data provisioning, and marketing and enrollment to aggregators on an accelerated timeline, with PJM communication staying with the EDC until aggregators register with PJM as DER Aggregators. ModernElectric recommended that EDCs handle distribution safety, filings, cost recovery, and settlement verification, while aggregators handle enrollment, device integration, dispatch,

customer support, and performance. Solar Landscape asked for a function-by-function transition plan in § 2.8(c), with each MFR filing naming who performs each function, the requirements for transfer, and the expected transition point, and allowing earlier transfer where a qualified aggregator meets them. Tesla supported EDC responsibility for distribution reliability, PJM administration, and data access, with competitive aggregators handling enrollment, device control, and marketing.

**Staff Response:** Staff notes that the Order provides details on the protocols, metrics, and measurements required to establish the programs. The PowerUp NJ Working Group will help refine these over time to adapt to market conditions. Each EDC must describe in its filing how dispatch authority, AMI data provisioning, PJM communication, and marketing and enrollment will transition to third-party aggregators over time.

Virtual Peaker and Voltus disagreed on the § 2.8(a) provision that lets existing Triennium 2 relationships carry over. Virtual Peaker supported carrying over existing Triennium 2 DR aggregator and OEM relationships into the VPP Interim Program without a new competitive solicitation, while requiring competition for any new or incremental capacity. Voltus asked the Board to strike the provision, stating that it creates a two-tier market, and to open all Interim Program capacity, not only incremental capacity, to competitive aggregator access no later than July 1, 2027.

**Staff Response:** Staff thanks the commenters for their feedback. Staff acknowledges that the VPP Interim program is designed to build upon the existing demand response programs but notes that the long term VPP tariff, which is already being worked on through the Grid Flex workgroup (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) will provide additional pathways for participation. Under the Order, existing Triennium 2 aggregator and OEM relationships may continue without a new solicitation, while any new or incremental third-party aggregator capacity must be selected competitively.

EnergyHub, ev.energy, Logical Buildings, Piclo, and RExChain all asked for a more open aggregator solicitation process. EnergyHub asked that EDCs not pre-determine participating aggregators, so any qualified aggregator can reach customers through the Edge DERMS. Piclo recommended one shared open procurement, with common qualification

standards across all four EDCs, instead of four separate RFPs. ev.energy asked for competitive, technology-neutral solicitations open to OEMs and independent aggregators, with criteria and timelines published before the December 31, 2026 filings. RExChain asked each EDC's MFR filing to establish a firm deadline, no later than Q2 2027, by which a competitive solicitation open to new independent aggregators must be issued. It also recommended that the solicitation's evaluation criteria give explicit, nondiscriminatory weight to aggregators with existing New Jersey customer relationships and verified generation data, regardless of whether those relationships originated through a Triennium demand-response program. Logical Buildings asked each EDC to disclose the capacity migrating from Triennium 2 and the quantity open to competition, to offer at least one open procurement, and to let aggregators contract directly with the EDC rather than through an incumbent implementation contractor or OEM.

> **Staff Response:** Staff thanks the commenters for their feedback and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long term open market compensation based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. As each of these programs is unique to the EDCs a shared solicitation cannot incorporate the differences in maturity of the programs nor can it bring programs to market fast enough to begin to address the affordability issues laid out in EO 1 and EO 2. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff.

ev.energy, Piclo, and SunStrong all asked for a minimum EDC-aggregator contract term. ev.energy and Piclo recommended at least two years rather than annual renewals plus published forward signals on long term tariff compensation ranges by Q1 2028. ev.energy also recommended treating the proposed twelve-month parallel-operation period as a minimum. SunStrong recommended a minimum EDC-aggregator contract term coextensive with the Interim Program, including the contemplated parallel-operation period, and a ten-year customer-specific incentive lock beginning on the date of enrollment. It further recommended confirming that a customer transitioning from the Interim Program to the long-term tariff would retain the committed rate for the remaining balance of the ten-year lock period.

**Staff Response:** Staff appreciates the comment and notes that the Order calls for a transition period both for current DR programs but also to the long-term tariff. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out, and long-term compensation will be addressed in a separate tariff proceeding. The Order requires a parallel-operation period of no less than twelve (12) months. Staff also notes that the Block 1 portion of the PowerUp NJ program does have a ten (10)-year term.

DCO, Nexamp, NJRCEV, and Solar Landscape all asked for durable, predictable, bankable revenue to support project financing. DCO recommended a contract or tariff commitment of at least seven years for qualified new projects. Solar Landscape stated that financing parties place greater value on fixed or otherwise predictable revenue and heavily discount compensation when both the payment rate and realized performance revenue remain variable. It therefore recommended combining performance accountability with a meaningful predictable multi-year revenue component and making the core economics applicable to a committed FOM storage project durable for at least fifteen (15) years. Nexamp asked for clear rules on commitment periods, availability and performance payments, payment timing, credit and collateral, event limits, and penalties. NJRCEV recommended clear, durable, and bankable compensation structures, with program rules, including eligibility criteria, performance obligations, dispatch requirements, M&V protocols, metering requirements, settlement procedures, and incentives structures, be set before launch.

**Staff Response:** The Order calls for a transition period both for current DR programs but also to the long-term tariff. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out, and long-term compensation will be addressed in a separate tariff proceeding. Staff also notes that the Storage portion of the PowerUp NJ program does have a ten (10)-year timespan. The Order addresses the requirements of both the VPP Interim Program and Block 1.

EnergyHub recommended balancing aggregator revenue certainty with the Interim Program's bridging role through compensation continuity rather than program continuity, with enrolled customers moving to equivalent-or-better compensation for the rest of their five-year commitment. It asked that EDCs have flexibility to set their own contracting structure, noting that aggregators of residential DERs typically work through Edge DERMS

providers that contract directly with the EDCs. EnergyHub cautioned against $/kW pay-for-performance and committed-MW contracts for residential DERs. It stated that these contracts do not reflect implementation costs or the full value of VPPs, and fit large, firm resources better than variable residential devices. It also stated that because customers can opt out, providers would bear performance risk they cannot control, which would raise contract costs.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order requires all EDC-aggregator contracts to be performance-based and to include a contracted MW commitment. The Order also requires each contract to include a transition clause enabling enrolled customers managed by a third-party aggregator to migrate to the long-term open-access tariff without re-enrollment, with a parallel-operation period of no less than twelve (12) months. Long-term compensation will be addressed in a separate tariff proceeding.

Logical Buildings, ModernElectric, Solar Landscape, and Turtle & Hughes all asked for standardized onboarding and contracting across the EDCs. ModernElectric asked each filing to include a standard third-party onboarding lane, with an intake process, consent form, data-sharing template, test-dispatch process, settlement timeline, and dispute process, and response targets of five business days for enrollment verification and unenrollment and ten business days for event-performance meter data. Solar Landscape asked for common minimum contracting terms, such as solicitation criteria, performance and settlement methodologies, payment schedules, transition procedures, and limits on contract termination and modification. It further suggested that implementation contractor and DERMS costs should be paid separately from grid service payments. Logical Buildings further recommended that the MFR Order require each EDC filing to identify whether enrolled VPP capacity would be claimed through the EDC's PJM Peak Shaving Adjustment Plan, made available for PJM capacity-market registration, or allocated between the two. It also recommended requiring each filing to explain the resulting treatment of participating customers' peak load contribution and installed-capacity tags, including any add-back; state whether customers or aggregators may elect among viable routes; and identify the plain-language disclosure of potential capacity-billing consequences that would be provided before enrollment. Turtle & Hughes asked for standardized application materials, defined review timelines, and rules letting authorized full-service providers manage applications, commissioning records, and compliance for customers.

**Staff Response:** The Order addresses requirements and payments and sets standards for the programs. The PowerUp NJ Working Group and the relevant subgroups will help design future standards and foster coordination among the EDCs.

Calibrant and Electrify America both asked the MFRs to address how much of each budget goes to incentives. Calibrant asked each EDC to disclose its incentive budget and expected $/kW rate, and to define a C&I storage enrollment pathway sized for commercial systems. Electrify America asked the MFR Order to require a minimum share for customer incentives and aggregator compensation, with a ceiling on administration and internal platform costs. It also asked that the solicitation target OEMs, independent aggregators, and owners of storage at public DC fast charging sites.

**Staff Response:** The budgets in the Order are the total budget including administration and incentives. The EDCs can propose the breakdown between the sub-budgets in their filings. Staff anticipates that the breakdowns will be different based on maturity of existing DR programs and size of territory.

EnergyHub stated that the proposed MFR structure is comprehensive and asked the Board to specify a common template for the Forecast Table and Budget Worksheet so the four EDC filings can be compared. It also asked the MFR Order to set a common minimum set of device-level fields for every dispatch event, across DER types: a unique device identifier, when the device was accepted into the VPP, device type and manufacturer, and interval load shed.

**Staff Response:** Staff thanks the commenter for the comment. The Order requires each EDC to file a confidential Event-Level Report covering each dispatch event, including MW dispatched versus MW delivered by VPP provider and by DER type, the number of customer opt-outs and of devices that did not respond, and settlement data. The EM&V subgroup of the PowerUp NJ Working Group will develop shared EM&V metrics and methodology and may consider standard device-level fields.

Edge Zero and Edgeli both asked that EDC Interim Program MFR filings disclose distribution data. Edge Zero asked each EDC to report its current transformer- and circuit-level monitoring coverage (DERMS Tier 1), separately from DR dispatch communications, with a Tier 1 build-out roadmap. Edgeli asked that hosting capacity, grid utilization, load, and grid need data be published as an MFR element in an open geospatial format

through a documented API, using a schema common to all four EDCs. Edge Zero also asked the Board to direct, through the PSUP proceeding, that each EDC's baseline distribution system assessment use transformer- or circuit-level telemetry, where available, rather than AMI-based estimates alone, and that each EDC state how much of the assessment relies on measured versus estimated conditions.

**Staff Response:** Staff thanks the commenters for their comments and notes that each EDC must describe in its filing how it will incorporate VPP grid services into distribution planning and operations, including coordination with its anticipated Proactive System Upgrade Plan filings. Distribution monitoring coverage and hosting capacity data may be addressed through the PSUP proceeding and the EDCs' DERMS planning under the Grid Modernization Forum (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid,* also BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*).

DCO and Foley both asked that the MFRs address customer-sited generation. DCO asked each EDC filing to include a C&I and institutional demonstration track for dispatchable CHP and CHP-enabled microgrids, an inventory of customer-sited generation and microgrids, and a method for identifying constrained circuits. Foley welcomed a dedicated MFR track for on-site BTM generation and suggested that the utilities invite units already permitted for this use to participate.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

Logical Buildings asked that proposals be scored by EDC staff or an independent evaluator with no competitive conflict, and that competing implementation contractors, OEMs, or affiliates not see other bidders' information. It asked the EDCs to publish qualification standards, fees, and scoring weights, to give applicants a cure period and written reasons for rejection, and to allow multiple awards. It also asked that contracts run through September 30, 2029, and that the MFR Order be organized around five implementation outcomes rather than a list of elements.

**Staff Response:** Staff notes that the Order calls for the EM&V subgroup of the PowerUp NJ Working Group to establish additional

metrics for review of the EDC-run programs and calls for an independent evaluator retained by the Board to verify program savings. The EDCs will be responsible for the selection of the aggregators they contract with for the VPP Interim Program, and selection of any new or incremental aggregator capacity must be competitive.

Virtual Peaker asked the Board to recognize DERMS and technology platform providers as a fourth role, distinct from the EDC, implementation contractor, and aggregator, so that third-party protections also cover the technology layer.

**Staff Response:** The Order provides a definition for VPP provider that would encompass many of these roles.

WeaveGrid asked that the Aggregator Solicitation Plan evaluate aggregators based on their ability to deliver the specific grid services identified by the EDC, including through device-level telemetry and consideration of distribution-system constraints. It also recommended providing aggregators with sufficient information regarding distribution constraints and anticipated grid needs to develop portfolios capable of delivering value where it is needed. It supported allowing both utility-administered offerings and third-party participation where each is cost-effective. EnergyHub asked Staff to reconsider the Aggregator Solicitation Plan, stating that the competitive solicitation and individual EDC-aggregator contracting requirements would add complexity, sideline capacity, and conflict with the open-access vision of the VPP program. It recommended an open program available to all qualified participants on identical terms, noting that each EDC already works with an edge DERMS provider that can bring any qualified entity into the program, and that the interim qualification criteria are sufficient without a competitive RFP.

**Staff Response:** Staff thanks the commenters for the comment and notes the Order requires each EDC's dispatch platform to segment enrolled resources by locational node, technology type, and response capability. Under the Order, an EDC shall not restrict participation to a single type of VPP provider or limit the number of VPP providers that may participate, and any entity that meets the VPP provider requirements and agrees to the required terms shall be permitted to participate. Any competitive procurement by an EDC is limited to its own systems and implementation services.

Tri-State recommended that utilities offer residential customers integrated solutions through their existing energy efficiency programs rather than new

competing programs, and stated that utility-run DERMS platforms can provide ancillary reliability benefits, including the ability to allocate and control resources by circuit to address circuit-level distribution issues.

**Staff Response:** Staff thanks Commenters for the comments and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff.

**xxxiv. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, SEIA/CCSA/NJSEC, Smart Thermostat Coalition, and VGIC

Advanced Energy United, the BTM Coalition, and SEIA/CCSA/NJSEC all asked for open participation rather than a limited set of contracted aggregators. The BTM Coalition asked that enrollment be open to any aggregator able to integrate with the utility's edge DERMS, in an uncapped bring-your-own-device program. SEIA/CCSA/NJSEC recommended using RFPs to select implementation partners, such as edge DERMS providers, rather than limiting participation to selected aggregators. They further recommended consistent performance compensation for all participants, subject to potential differences based on device type. Advanced Energy United asked the utilities to also propose a walk-up tariff option for OEMs, third-party owners, and DERMS providers, paid on a $/kW basis like ConnectedSolutions. It also asked the Board to define a third-party supplier pathway, noting that Executive Order No. 2 calls for VPPs administered by EDCs and third-party suppliers, while the Straw Proposal's pathways and licensing are built only around aggregators.

**Staff Response:** Staff thanks Commenters for the comments and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The Straw clearly outlines a long-term vison that is focused on robust, open third-party participation. Under the Order, a VPP provider is defined by the function it performs rather than by entity type, so a third-

party supplier that aggregates and dispatches customer DERs may participate as a VPP provider.

EEA-NJ and SEIA/CCSA/NJSEC both supported having new customers start under the VPP framework rather than the Triennium. EEA-NJ stated that this avoids an unnecessary administrative burden. SEIA/CCSA/NJSEC supported a phased launch only if it gets customers into the VPP sooner and treats similar customers fairly, with existing Triennium commitments honored or converted voluntarily without loss of benefits. SEIA/CCSA/NJSEC also suggested that the Board establish a firm transition date, and rules against duplicate payment.

**Staff Response:** Staff thanks the commenters for the comments and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The EDC filings must include a transition plan to make the switch as seamless as possible for customers.

Advanced Energy United, the Smart Thermostat Coalition, and VGIC all asked for enrollment paths that do not require customers to enroll again. Advanced Energy United and the Smart Thermostat Coalition both requested OEM-led enrollment from the beginning of the Interim Program, but their recommendations differed in detail. Advanced Energy United stated that customers who have already opted into VPP participation generally should not be required to execute a duplicative enrollment agreement administered by an EDC or program administrator. The Smart Thermostat Coalition recommended permitting OEM-led enrollment under a manufacturer's existing company-level terms of service where those terms satisfy grid-event participation and customer-consent requirements, rather than requiring a separate utility-administered, program-specific agreement. VGIC asked that contracts let enrolled customers, with their authorizations and integrations, move into the long-term tariff without re-enrollment.

**Staff Response:** Staff thanks Commenters for the comments and notes that the EDC run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff.

The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff. The Order and Straw reference the Triennium budgets as part of the basis for the recommended budget for these programs.

ChargEVC, SEIA/CCSA/NJSEC, and VGIC all supported a strong aggregator role in the Interim Program. SEIA/CCSA/NJSEC and VGIC asked the Board to use aggregator capabilities now rather than waiting for the long-term tariff, with EDCs keeping responsibility for identifying grid needs and maintaining reliability. SEIA/CCSA/NJSEC added that EDCs should provide AMI data where needed and orchestrate VPP assets through implementation contractors such as an edge DERMS, while aggregators handle customer acquisition, enrollment, device integration, dispatch, and PJM participation, with firm transition dates and protection of data portability, consent, and settlement continuity. ChargEVC stated that aggregators will play an important role, especially for EVs, and that programs should be designed to ensure their participation.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The PowerUp NJ Working Group will help establish the long-term framework that best addresses how the EDCs and aggregators will interact.

The BTM Coalition and SEIA/CCSA/NJSEC both asked that compensation terms, including the $/kW rate, apply for at least five (5) years from enrollment. SEIA/CCSA/NJSEC also recommended Interim contracts of at least three (3) years, with compensation honored through the term. The BTM Coalition asked that payments go to the system owner, be assignable to a designee, or split between them.

**Staff Response:** The Order calls for a transition period both for current DR programs but also to the long-term tariff. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out, and long-term compensation will be addressed in a separate tariff proceeding. Staff also notes that the Storage portion of the PowerUp NJ program does have a 10-year timespan. The Order addresses the requirements of both the VPP and Storage programs.

The BTM Coalition and SEIA/CCSA/NJSEC both proposed specific MFR changes. The BTM Coalition recommended establishing a $250/kW launch rate that would be updated for future enrollees as additional grid-service values are identified; allow existing systems and net-metered customers to participate, including battery exports during dispatch events; and provide enrolled customers with a minimum five-year lock-in of their initial compensation rate and program terms, followed by an option to transition into an available successor program. It further recommended requiring EDCs to document existing DERMS-provider capabilities and plans for integrating storage OEMs, third-party owners, and aggregators; establishing device-level battery-performance measurement; addressing any DERMS procurement and eligible-device participation strategy within the Aggregator Solicitation Plan; eliminating the proposed EDC-aggregator contract-disclosure requirement; and developing public participation, performance, and event-data reporting that would not delay program launch. The BTM Coalition also recommended designing the Interim Program to transition into the long-term VPP framework rather than requiring it to be retired or comprehensively redesigned. SEIA/CCSA/NJSEC recommended uniform statewide MFRs limited to information necessary for oversight and settlement and proposed changes in six areas: a more prescriptive storage-program description; documentation of existing DERMS providers and plans for integrating storage devices, third-party owners, and aggregators; device-level performance measurement and EM&V; an Aggregator Solicitation Plan supporting open enrollment of eligible assets; replacement of EDC-aggregator contract disclosures with standard program terms and conditions; and public reporting of aggregate event-level data. They recommended that event reports include requested and delivered kW or kWh, baselines, availability, opt-outs, telemetry quality, and payment calculations, supplemented by monthly operating reports, quarterly public scorecards, and an annual independent evaluation. They further recommended keeping customer data, cybersecurity details, trade secrets, and portfolio strategies confidential while making aggregate performance, costs, benefits, enrollment, and EDC service levels public.

**Staff Response:** The Order calls for a transition period both for current DR programs but also to the long-term tariff. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out, and long-term compensation will be addressed in a separate tariff proceeding. Staff also notes that the Storage portion of the PowerUp NJ program does have a 10-year timespan. The Order addresses the requirements of

both the VPP and Storage programs and allows the EDCs to propose compensation models that are comparable in value to the companion PowerUp NJ Storage level.

**xxxv. Advocacy Groups**

Commenter(s) Referenced in This Summary: CJNJ, Evergreen Action and EDF, New Jersey LCV, NJECN, NJEJA, and Vote Solar

Evergreen Action and EDF, New Jersey LCV, NJECN, and Vote Solar all asked for broader third-party participation from the start of the Interim Program. Evergreen Action and EDF asked the Board not to treat the four functions as one bundle, to set a condition and an outside date for transferring each, and to open enrollment and outreach to licensed aggregators, community-based organizations, and mission-based organizations from the start. Vote Solar asked the Board to replace the contract-based framework with open access, using simple technology-neutral enrollment and consistent compensation. New Jersey LCV asked that customers be able to enroll directly through their equipment providers, with OEMs and third-party owners able to receive dispatch signals and program payments. NJECN asked that existing aggregators, such as Sunrun and Tesla, be brought into EDC programs immediately.

**Staff Response:** Staff thanks Commenters for the comments and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The Straw also talks about preserving customer choice both in the Interim and long-term programs, which is reflected in the Order. The learnings from the Interim program will help shape the long-term program (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*).

Evergreen Action and EDF, NJEJA, and Vote Solar all asked that solicitations and filings include equity provisions. Evergreen Action and EDF asked that customer-choice and equity targets be built into the solicitation and weighted in aggregator selection, with kW targets by community type and constrained area. NJEJA asked that at least 30% of VPP contracts be reserved for community-owned aggregators, phased in at 15%, 25%, and 30%, with an added 10% preference for aggregators

based in overburdened communities and preference points in every solicitation. Vote Solar asked that MFR filings include added incentives for DERs in LMI and overburdened communities, EM&V tracking of participation, and outreach with community organizations.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the future EM&V subgroup of the future PowerUp NJ Working Group to establish future goals, measurements and metrics. For the VPP Interim Program, each EDC must describe how its program will reduce barriers to participation for LMI customers and customers in overburdened communities and must report participation by these customers.

Evergreen Action and EDF differed from Vote Solar regarding the proposed bifurcated start. Evergreen Action and EDF supported it, with customers who enroll after approval going directly into the VPP. Vote Solar considered the proposed division between new and existing assets confusing and recommended an open-access, bring-your-own-device Interim VPP modeled on ConnectedSolutions that would provide equal participation opportunities for new and existing devices, including existing non-Triennium BTM batteries. Under Vote Solar's proposed structure, GSESP would complement the VPP by providing upfront and hardware incentives for BTM and FOM storage and tailored compensation for FOM or specialized projects not captured by the BTM-focused VPP.

**Staff Response:** The Order calls for a transition period both for current DR programs but also to the long-term tariff. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out, and long-term compensation will be addressed in a separate tariff proceeding. Staff notes that storage and existing storage devices are addressed in the GSESP Block 1 section of the Order.

Evergreen Action and EDF asked the Board to keep event-level reporting and to publish non-identifying data, including enrolled capacity by territory, events and load reductions, participation by customer segment and overburdened community, and avoided emissions. It also asked that aggregators report participation by DER type, community type, and grid location, and that confidentiality be narrowly tailored.

**Staff Response:** Staff thanks the commenters for the feedback and notes that the future EM&V subgroup of the future PowerUp NJ Working Group to establish future goals, measurements and metrics.

The Order also requires public quarterly, annual, and post-season reports, with event-level data kept confidential.

Evergreen Action and EDF asked that EDC-aggregator contracts run through the Interim Program and an orderly transition, that Interim compensation phase out over about 24 months, and that the 12-month parallel operation period be treated as a floor.

**Staff Response:** The Order calls for a transition period both for current DR programs but also to the long-term tariff. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out, and long-term compensation will be addressed in a separate tariff proceeding. The Order requires a parallel-operation period of no less than twelve (12) months.

CJNJ asked that utilities that competitively procure installation from pre-qualified contractors bundle multiple projects into one contract, to achieve economies of scale and support contractors with highly skilled workforces.

**Staff Response:** Staff thanks the commenter for their feedback and notes that the Straw Order indicated that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

### xxxvi. Program Implementers and Administrators

Commenter(s) Referenced in This Summary: Ampion, Energy Solutions, Michaels Energy, and Power TakeOff

Michaels Energy expressly recommended multi-year contractual certainty, while Energy Solutions cited an existing automated demand-response program as an example of how longer-term participation can support persistent, dispatchable load reductions. Energy Solutions reported that customers in that program commit for three (3) or five (5) years after installation and, on average, deliver 95% of their committed load shed during events. Its related recommendation was that the Board support coordination among existing energy-efficiency, demand-response, and VPP programs concerning installation, enrollment, incentives, controls, and M&V. Michaels Energy recommended fixed capacity payments for committed MW performance payments during called events, terms covering at least four event seasons, and payment for completed work if an EDC changes or ends the program.

**Staff Response:** Staff thanks the commenters for the comments and notes that EDC-aggregator contracts must include a contracted MW commitment with incremental enrollment goals over the contract term. The Order does not set a minimum contract term, and each EDC proposes its incentive structure, including any fixed enrollment and pay-for-performance components, in its filing. Evaluating these compensation structures is an objective of the VPP Interim Program.

Michaels Energy and Power TakeOff both asked that EDCs be able to procure specialized functions, not only full-service aggregators. Michaels Energy asked that solicitations allow combined teams and prime and subcontractor structures. that each solicitation includes a C&I implementation track. Proposed evaluation criteria included experience recruiting and retaining midsize and large or complex C&I customers; methods for estimating and testing reliably deliverable kW; baseline, metering, and EM&V capabilities for weather- and production-sensitive loads; controls and gateway integration; management of thermal energy storage, refrigeration, HVAC, lighting, and process-load flexibility; and commissioning, safety, customer support, and post-event corrective action.. Michaels Energy also supported the use of a rolling technology-qualification process. Power TakeOff recommended a single EDC-contracted AMI data analysis provider, separate from the implementation contractor, working on behalf of the third-party aggregator program. It stated that this provider could identify and recruit the customers who would benefit most from enrolling, including LMI customers, and refer them to aggregators; verify enrollment; measure event performance impartially; and separate the contributions of multiple devices at one premise. Power TakeOff asked that the provider's contract prevent preferential access for EDC-affiliated aggregators.

**Staff Response:** Staff acknowledges the comments and notes that the Order allows each EDC to deliver its program through EDC staff and contracted implementation contractors and does not restrict solicitations to a single aggregator type. Each EDC must describe in its filing how it will use employees, contractors, or both, along with its contractor requirements and solicitation plan.

Ampion asked the Board to move responsibility for settlement and cross-market verification in the Interim Program from EDCs to licensed VPP Settlement Administrators. It asked each MFR filing to show how EDC systems will work with any Board-licensed settlement administrator through standardized data feeds and reconciliation interfaces. It further suggested

that no EDC affiliate should be permitted to compute aggregator compensation without independent reconciliation to preserve long-term open and competitive market architecture. More to that point, it asserted that interoperability with a market of VSAs will keep the settlement layer competitive and prevent EDCs from directing aggregators to a preferred settler. Ampion also stated that VSAs could help address the revenue-certainty concern.

**Staff Response:** Staff acknowledges the comment and notes that the Order does not establish a separate settlement administrator role for the VPP Interim Program. Verification of program savings will be performed by an independent evaluator retained by the Board, and each EDC must describe the data, systems access, and records it will make available to that evaluator, including event-level and settlement data. Each EDC must also report amounts paid to each VPP provider by payment type.

Energy Solutions asked that utility filings cover, at a minimum, eligible technologies and controls, enrollment and opt-out, baseline and performance methods, dispatch notice, data access, privacy, cybersecurity, DER registry, aggregator qualification and licensing, performance-based incentives, and cost recovery.

**Staff Response:** Staff appreciates the comment and notes that Attachment A addresses most of these elements, including eligible technologies, enrollment, baseline and performance methods, dispatch notice, customer data access, cybersecurity and data privacy, incentive structure, and cost recovery. The DER registry and aggregator licensing are expected to be developed through the PowerUp NJ Working Group over the next 30 months.

### xxxvii. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

Base Power asked the Board to establish a third-party supplier pathway in § 2.8, alongside the two EDC-administered pathways, in both the near-term framework and the MFR Order, noting that this is its operating model in Texas and Illinois. It also asked for a new MFR subsection requiring EDCs to gather and report information from supplier VPPs, include it in Peak Shaving Adjustment Plans, and update peak load contribution accounting consistent with applicable FERC-approved wholesale-level accounting methods.

**Staff Response:** Staff thanks the commenter for the comment. Under the Order, a VPP provider is defined by the action it performs rather than by the type of entity performing it, and third-party electricity suppliers are among the entities that may qualify. The Order therefore does not create a separate supplier pathway. Each EDC must submit a PSA plan to PJM by September 10 of each year, or PJM's earlier deadline, beginning in 2027, covering its VPP Interim Program and other DR programs it manages that can meet PJM's PSA requirements. The Order also directs each EDC to develop a plan to revise its PLC calculation and reporting methods to account for negative PLCs, and to file a summary of that plan with the Board by February 12, 2027. Staff anticipates that each EDC's Midterm Report will inform how these mechanisms carry into the long-term framework.

NRG asked the Board to design utility programs to maximize, not merely permit, third-party aggregator participation. It supported having customers who join after Board approval enroll directly under the VPP, with existing participants kept on current terms and voluntary migration of aggregator portfolios. It asked that enrollments, contracts, and data access rights carry forward through the transition, with functions moving to aggregators on a defined schedule and no re-enrollment, and that the minimum contract term be long enough to recover customer acquisition costs. It also supported a standardized statewide MFR with at least annual, automated reporting.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that each EDC must offer a third-party aggregator pathway and describe how dispatch authority, AMI data provisioning, PJM communication, and marketing and enrollment will transition to aggregators over time. EDC-aggregator contracts must include a transition clause that allows enrolled customers to migrate to the long-term tariff without re-enrollment. Each EDC must also file quarterly and annual reports, and the Order specifies common benefit and cost line items across the EDCs.

### xxxviii. Financial Services

Commenter(s) Referenced in This Summary: Syntropic

Syntropic asked the Board to state that an entity that finances equipment but does not hold enrollment, dispatch resources, or register with PJM is not a DER aggregator requiring a license.

**Staff Response:** Staff thanks the commenter for the comment and notes that the Order defines a VPP provider by the function it performs: aggregating behind-the-meter DERs and dispatching them to deliver a measurable reduction in demand. Aggregator licensing requirements will be addressed as that framework is developed through the PowerUp NJ Working Group.

### xxxix. Individuals and Academic Institutions

Commenter(s) Referenced in This Summary: Cammie Croft, Digital Verity, Michael Winka, and UDelaware

Cammie Croft asked that Interim Program solicitations follow a published schedule of open windows, such as twice a year, rather than discretionary Requests for Proposals ("RFPs") at unannounced times.

**Staff Response:** Staff notes that the program is intended to run for 2 years, solicitations would prolong the Interim step. The Interim program is designed to build the market while the Staff continues work on the long-term tariff. Each EDC must describe its solicitation plan in its filing, including a timeline that allows selected aggregators to begin enrollment.

Michael Winka recommended that utilities keep the functions noted in section § 2.8 during the Interim Program. In the long-term program, he recommended that the utility act as the dispatch authority, like a DSO, with marketing and enrollment left to aggregators. He further suggested that the long-term program establish utility authority to handle licensing aggregators, pursuant to Board regulation.

**Staff Response:** The Order clearly outlines the administrative responsibilities of the EDCs during the interim program. Aggregator licensing is contemplated in the Straw and will be addressed in a future proceeding.

UDelaware recommended allowing third-party VPPs in some initial sandbox programs, with direct communication to PJM and an EDC right to request override under FERC Order No. 2222. For ECD-VPP communications and other requirements, it suggested starting with one VPP per EDC, since coordinating several VPPs may be too complex at first, and moving to commercial or multiple VPPs later. UDelaware also noted that there could potentially be different VPPs with each different EDC's sandbox program.

**Staff Response:** The interim program will be an EDC administered program where EDCs may contract with a VPP provider. The Straw and Order also require that the EDCs continue to offer customer choice in creating their programs.

Digital Verity expressed support for the reasoning behind the § 3.7(b) proposed cap on any single aggregator of 40% of enrolled capacity to reduce correlated dispatch failure risk but noted that this same reasoning should apply to equipment manufacturers and DERMS platforms.

**Staff Response:** Staff appreciates the comment and notes that the single-aggregator concentration limit referenced is part of the long-term framework described in the Straw Proposal and is not included in the VPP Interim Program established by the Order. Concentration risk across equipment manufacturers and DERMS platforms may be considered as the long-term framework and its performance standards are developed.

# 6. Long-Term Transition, Tariff & Compensation

***Straw Proposal section(s):*** *Section 3 introduction, § 3.1–3.7*

**Summary of Comments:** Most commenters supported a milestone-based move from the Interim Program to a long-term, open-access VPP tariff, but disagreed on how strict the milestones should be. The utilities and Rate Counsel asked the Board not to lock in a tariff before the Interim Program is evaluated, while aggregators, developers, and advocates asked for an outside date, early commercial terms, and a market opening that does not wait for full Grid DERMS build-out. Most commenters supported the three-pathway structure, with requests to size Pathway 1 to device costs, make Pathway 2 optional or locational, and set payment levels outside the tariff by grid service. Many opposed a uniform seven-year enrollment period and the 40% concentration cap. Commenters split on the 70% pass-through floor: the utilities and third-party owners preferred disclosure and an offer-comparison platform, while several advocates supported a floor. Developers asked for bankable revenue, durable locational signals, and stacking rules that bar only paying twice for the same service in the same interval. Many also asked for a formal, time-bound EDC-aggregator dispute resolution process.

### xl. Utilities and Utilities Association

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, RECO, and NJNG

JCP&L, NJUA, and PSE&G all cautioned against setting the long-term market structure before the Interim Program is evaluated. NJUA stated that it is too early to presume if a tariff-based structure will be the optimal long-term solution and recommended a data-driven approach in which Interim Program findings on customer participation, technology performance, aggregation models, and operations guide the design of the permanent framework. JCP&L asked that any long-term tariff be developed in a separate process, after the Board clarifies tariff ownership, EDC and aggregator roles, cost recovery, customer protections, and retail and wholesale boundaries. PSE&G stated that the proposal casts the EDCs in a passive role, while they must remain the "aggregator of aggregators," and asked for a working group with the EDCs and other stakeholders to resolve open issues, including PSUP alignment.

**Staff Response:** Staff thanks the commenters for the comment and notes that many of the decisions regarding the long-term tariff will be determine in future Grid Mod proceedings (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid,* also BPU Docket NO. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*).

ACE, NJUA, PSE&G, and RECO all asked that the long-term tariff launch only after demonstrated readiness. ACE supported the four milestones but stated that open access should wait for approved PSUPs, GridFlex service definitions, DERMS capability, cybersecurity and data standards, settlement processes, and Interim Program results, with proof of reliable dispatch and M&V. RECO recommended adding an additional "sandboxing" milestone to confirm that programs work, are incentivized correctly, and are cost-effective. PSE&G stated that Grid DERMS Tier 2 or 3 maturity is a necessary prerequisite for open access, while RECO preferred a trigger based on demonstrated functionality rather than a DERMS tier. On the PSUP, ACE asked for standardized, machine-readable data on constrained circuits, load growth, hosting capacity, planned upgrades, and locational priorities, while RECO recommended general tariff terms with details posted on EDC websites.

**Staff Response:** Staff thanks the commenters for their feedback and notes that many of the decisions regarding the long-term tariff will be determine in future Grid Mod proceedings (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric*

*Grid,* also BPU Docket NO. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*) and after the VPP Interim Program Mid-term Review.

ACE, NJNG, PSE&G, and RECO all commented on the three-pathway structure and default payments. ACE supported the structure, with payments set by grid service and Pathway 1 sized to enrollment and connectivity costs. RECO stated that distribution peak reduction and performance should form the basis for compensation. It stated that Pathway 1 enrollment incentives should be transitional, limited to overcoming market barriers or supporting emerging technologies, and offered as program incentives rather than tariff rates so they can be revised more easily. For Pathway 2, RECO stated that payments should be reduced or omitted where Pathway 3 already captures a resource's availability, that DERs should receive no compensation where added discharge would not lower the local distribution peak, and that EDCs should have the option to use competitive solicitations where peak shaving capacity is limited. RECO supported Pathway 3. NJNG supported pay for separate, measurable services without duplicate payments. ACE and RECO both recommended baseline terms in the tariff, with payment levels set separately by grid service and use case. PSE&G asked that the pathways be guidelines only, so EDCs can use any or none of them, and opposed default structures or baseline terms that limit EDC flexibility.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order does not establish the long-term tariff design, including the three-pathway structure described in the Straw Proposal. Over the next 30 months, the EDCs are expected to work with Staff on a petition for a compensation tariff based on the GridFlex recommendations, informed by the results of the VPP Interim Program Midterm Review. Compensation structures, including fixed enrollment payments and pay-for-performance models, will be evaluated during the Interim Program to inform that tariff design.

ACE and RECO both supported a minimum enrollment period and locational pay, with flexibility. ACE found seven years reasonable for most devices, with shorter or longer terms by cost and equipment life, while RECO stated that the period should vary by incentive amount, resource type, and benefit period. ACE recommended adjusting locational pay when a feeder is no longer constrained, and RECO stated that broader geographic targeting may be more practical at first.

**Staff Response:** Staff appreciates the commenter's feedback and notes that the Order does not set a minimum enrollment period or locational payment levels for the long-term framework; these will be addressed as the long-term tariff is developed. During the VPP Interim Program, quantifying distribution-level grid service values is a program objective, to build the evidence needed for any future procurement of locational distribution benefits.

ACE, JCP&L, PSE&G, and RECO differed on dated Grid DERMS requirements. ACE supported minimum functions tied to dates, such as secure data exchange, near-real-time telemetry, dispatch visibility, and use of PSUP outputs, noting that its own timeline includes DERA orchestration from day one. PSE&G recommended functional objectives rather than fixed deadlines. RECO, which does not have a fully deployed Grid DERMS, recommended that any timeline be nonbinding. JCP&L recommended that the Interim Program initially leverage existing utility capabilities, third-party implementation platforms, customer-sited technologies, and operational processes. It proposed evaluating advanced DERMS functionality, information and operational technology integration, telemetry platforms, and supporting infrastructure through the PSUP and related planning processes as operational needs and benefits are demonstrated, rather than treating those investments as launch prerequisites before program requirements, use cases, performance expectations, and cost-recovery mechanisms are established.

**Staff Response:** Staff acknowledges the comments and notes that the Order does not set dated Grid DERMS requirements. The Order recognizes that enhanced DER management capabilities will likely be necessary for the long-term framework, and the EDCs are expected to develop a plan to establish DERMS in the future proceedings.

ACE, PSE&G, and RECO all opposed a fixed pass-through percentage, and PSE&G and RECO also raised concerns about the 40% cap. ACE preferred a public offer-comparison platform, standard disclosures, and transparent reporting, with any later floor based on market experience. PSE&G stated that a 70% floor may exclude some third-party aggregators, and noted that many OEMs act as aggregators with large market shares. RECO preferred transparency and customer choice, opposed the 40% cap as a procurement and reliability risk where few aggregators enroll, and recommended a graduated approach to the 80% performance threshold.

**Staff Response:** Staff acknowledges the comments' feedback and notes that the Order does not adopt a fixed pass-through floor or the concentration cap described in the Straw Proposal. For the VPP Interim Program, the Order sets a goal of passing through no less than seventy (70) percent of aggregator compensation to participating customers, with tracking rather than a contractual mandate, so that the Board can observe actual practice across EDCs and aggregator business models before setting any binding floor.

ACE and PSE&G both supported a formal EDC-aggregator dispute resolution process. ACE cited the value of the State's interconnection dispute process, while PSE&G asked that the process stress collaborative resolution before Board involvement and not delay operating decisions needed for reliability. RECO asked that open-access rules preserve EDC operating flexibility.

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Order does not establish a formal EDC-aggregator dispute resolution process for the VPP Interim Program. The need for such a process may be considered as the long-term framework is developed, including through the PowerUp NJ Working Group.

ACE, JCP&L, PSE&G, and RECO addressed how the long-term framework should coordinate distribution services, State VPP compensation, and wholesale-market participation. ACE supported stacking compensation for distinct, measurable, and verifiable services, subject to clear M&V, dispatch-priority, settlement, and anti-duplication rules, and recommended a compensation-stacking order to prevent duplicate payments. It also stated that PJM participation should remain available but should not be a prerequisite for Interim Program eligibility. JCP&L recommended that EM&V distinguish reductions already reflected through wholesale-market participation from incremental reductions attributable to VPP Interim Program activities, while preventing the same response from being credited more than once and recognizing distinct services provided to different markets. RECO recommended identifying, valuing, and compensating distribution services separately from wholesale-market value, with clear rules governing dispatch priority and overlapping value streams. PSE&G stated that distribution-level signals should take priority when they conflict with PJM signals and requested further discussion of obligations, risk allocation, and double counting before relying on Peak Shaving Adjustment Plans.

Regarding service-pathway design, ACE and RECO recommended beginning with a limited number of service categories and refining them as operational experience develops. JCP&L recommended calibrating measurement, telemetry, and reporting requirements to the particular service and value provided. PSE&G identified sustained duration as an important distinguishing criterion, particularly for distribution-deferral applications, and recommended leaving detailed technical criteria to the EDCs rather than prescribing them in the framework order.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the Straw Order indicated that unlocking these multiple compensation streams while guarding against double payment is a long-term goal. notes that many of the decisions regarding the long-term tariff will be determined in future Grid Mod proceedings *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)*. Staff also notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

**xli. Division of Rate Counsel**

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel was extremely skeptical of the long-term framework and recommended deciding any long-term tariff or expanded utility investment in a separate, later proceeding based on verified Interim Program results. It stated that no interim contract should create an entitlement to long-term compensation.

**Staff Response:** Staff acknowledges the comments and notes that the Order does not establish the long-term tariff. Any long-term compensation tariff will be considered through a separate petition based on the Grid Flexibility Services recommendations (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*), informed by the VPP Interim Program Midterm Review. The Order treats the Interim Program as transitional, and following the Midterm Review the Board will determine whether it should be continued, modified, expanded, or phased out.

Rate Counsel stated that rural grid upgrades needed for utility-scale solar should not be paid by captive ratepayers, and that upgrade costs caused

by added solar and storage belong in cost-effectiveness tests. It recommended a DER export tariff with per-kW and per-kWh charges, interconnection fees modeled on contribution in aid of construction (CIAC), and a separate exporting-DER class in the EDCs' next rate cases.

**Staff Response:** The PowerUp NJ program is designed to compensate participants for the service they provide to the grid, hardware and installation costs are not contemplated as costs in this program. A Grid Mod Working group *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)* is working to design the long-term tariff to provide such compensation for devices, including exporting storage.

Rate Counsel recommended that all ratepayer-funded incentives be pay-for-performance, with enrollment incentives left to aggregators and no extra pay for sustained participation. It recommended a 50% cost-reduction target, meaning VPP costs well below the average capacity cost of about $104/kW-year and preferably near $52/kW-year. It proposed that EDCs select the best aggregator offers, set a uniform price (about $57.72/kW-year on average), or run a reverse auction, and supported a defined contract length, such as a five to seven years guaranteed program length, to give third-party aggregators certainty.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order does not set long-term compensation levels or procurement methods; these will be addressed as the long-term tariff is developed. For the VPP Interim Program, all EDC-aggregator contracts must be performance-based, with payments reduced as response rates decline and a ceiling on the cost per kW consistent with avoided-cost benchmarks. Each EDC must also report cost to achieve, in dollars per kW of verified load reduction, as a performance indicator.

Rate Counsel opposed the seven-year minimum enrollment period as too long and recommended reviewing incentive rates at least annually. It stated that thermostat, EV charger, and similar incentives from other programs should be offered only if they are cost-effective on their own, in which case VPP enrollment should not be required.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order does not adopt a minimum enrollment period for the VPP Interim Program. Hardware incentives continue to be offered through other Board-approved programs, provided they do not

duplicate VPP compensation, and those programs are reviewed in their respective proceedings.

Rate Counsel stated that most DERs cannot serve wholesale and local distribution needs at the same time. It recommended keeping wholesale and local dispatch and compensation separate unless a resource shows enough capacity for both, and expected locational T&D value and voltage support to be small. It favored location-specific T&D estimates, with payments targeted at 50% of that value.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that, for the VPP Interim Program, each EDC must describe how it will treat revenue from PJM programs for co-enrolled customers and the safeguards that prevent double compensation for the same service. Load reduction during distribution and other grid stress events is reported separately from load reduction during the 5CP hours, which will provide data on how local and system needs align. The treatment of wholesale and local value in the long-term framework will be addressed as that framework is developed.

Rate Counsel recommended that the Board set minimum functions the EDCs must achieve by specific dates, without requiring a DERMS or any particular solution. It did not recommend a minimum customer pass-through requirement, stating that it divides a payment without showing the payment is needed, and it supported a formal EDC-aggregator dispute resolution process.

**Staff Response:** Staff appreciates the comments and notes that the Order does not require a specific DERMS solution and anticipates that the EDCs will develop a plan to establish DERMS Tier 2 capability over the next 30 months. For the VPP Interim Program, the Order sets a seventy (70) percent customer pass-through goal with tracking rather than a mandate, so the Board can observe actual practice before setting any binding requirement. The Order does not establish a formal dispute resolution process at this stage.

**xlii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, Edge Zero, Edgeli, Electrify America, EnergyHub, ev.energy, Honeywell, Koolbridge, Logical Buildings, Lunar, ModernElectric, Nexamp, Piclo, Recurve, Renew

Home, RExChain, Solar Landscape, Soltage, SunStrong, Tesla, Tri-State, Uplight, Virtual Peaker, Voltus, and WeaveGrid

Edge Zero, EnergyHub, ev.energy, Piclo, Renew Home, Solar Landscape, Virtual Peaker, and WeaveGrid all addressed the milestones and Grid DERMS timing. ev.energy, Solar Landscape and Virtual Peaker requested dated DERMS milestones or implementation schedules. ev.energy and Virtual Peaker identified Tier 2—control and dispatch—as the appropriate open-access trigger rather than Tier 3. Solar Landscape requested a dated, tier-specific implementation schedule and Tier 2 target but opposed making full Tier 2 implementation an absolute prerequisite where a resource can already be dispatched, measured, verified, and settled using available EDC systems. Virtual Peaker asked that Tier 2 be defined with specific, auditable technical criteria, such as minimum device classes under active control, dispatch latency, and confirmation of receipt capability, and Edge Zero asked for a Tier 1 visibility timeline as a precondition for Tier 2. Edge Zero also asked the Board to tie the feasibility of location-differentiated Pathway 2 payments and locational dispatch targeting to the Tier 1 monitoring build-out, and to treat progress on the locational value map as a reportable readiness indicator. Piclo recommended that opening the open-access market be based on three testable capabilities rather than a DERMS maturity tier: the ability to register and verify enrolled assets, issue and confirm dispatch signals through a defined API, and exchange settlement-grade meter data within twenty-four hours. Renew Home separately recommended allowing aggregator-pathway participation to proceed while Grid DERMS capabilities are developed rather than conditioning participation on Grid DERMS build-out status. EnergyHub recommended an EDC capability assessment and investment roadmap keyed to the Tier 1–4 framework without fixed tier-completion dates. WeaveGrid supported Board-established milestones and phased, territory-specific implementation plans reflecting each utility's existing systems, near-term program needs, and prudent investment paths. Solar Landscape also recommended that the broader milestones function as a coordinated roadmap rather than absolute gates and that core commercial terms be established in 2027 using bounded parameters, together with a firm statewide effective date, so storage projects can be financed before federal tax credits expire in 2032.

**Staff Response:** Staff thanks the commenters for their feedback and notes that many of the recommendations regarding Grid DERMS will be determine in future Grid Mod proceedings (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for*

*Aggregated DER Participation in New Jersey's Modernized Electric Grid,* also BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*).

ev.energy, Honeywell, Virtual Peaker, and WeaveGrid all addressed DERMS roles and access. Honeywell asked the Board to define functions and decision rights rather than a vendor architecture, with EDCs keeping operating authority. WeaveGrid asked that Grid and Edge DERMS be treated as complementary parts of a utility-led architecture. ev.energy and Virtual Peaker asked that EDCs publish Grid DERMS interface specifications on open terms, with Virtual Peaker asking that the Board require EDC's to give at least 90 days' notice before implementing any changes to technical specifications. It recommended the Board state clearly that this equal-access protection covers the technology companies that build and operate the software an aggregator or EDC uses to connect to the grid.

**Staff Response:** Staff thanks the commenters for their feedback and notes that many of the decisions regarding Grid DERMS will be determine in future Grid Mod proceedings (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid,* also BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*).

Edgeli, ev.energy, Piclo, and RExChain requested detailed EDC grid-need data for VPP market participants, while Solar Landscape separately addressed the grid information to be produced through the PSUP. Edgeli asked for required feeder-level utilization metrics, hourly or sub-hourly seasonal load shapes, and, for each need, the MW, hours, and need-by date. Piclo recommended that forward-looking PSUP grid-needs data, including constrained circuits, need windows, MW quantities, and indicative values, be published in a machine-readable format common across all four EDCs and refreshed no less than annually, with interim updates for material changes in system constraints. ev.energy and RExChain requested that the Board mandate, as part of the Interim Program MFR, that each EDC disclose to registered and prospective aggregators the specific distribution zones, feeders, or substations within its territory that are recurrently constrained during historical grid-stress conditions. Solar Landscape asked

for both export and import hosting capacity and public maps of areas with added locational value as a result of the PSUP.

**Staff Response:** Staff thanks the commenters for their feedback on data access and notes that future reporting requirements, metrics and methodologies will be discussed in the PowerUp NJ Working Group and the Grid Flexibility Services workgroup (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*). Staff also thanks the commenters for their feedback on the PSUP, the progress of which can be seen via BPU Docket No. QO24030199 (*In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*). Staff has taken the commenter's insight on what is needed from the PSUP and taken it into consideration in that proceeding.

DCO, EnergyHub, Lunar, Piclo, RExChain, Solar Landscape, Uplight, and Voltus all supported the three (3) pathway structure, several with refinements. Voltus and Lunar stated that it pays for what a resource delivers. Piclo called Pathway 2 the structurally important element, since pay for committed availability makes revenue predictable. EnergyHub asked that Pathway 1 (Enrollment) be sized by device class. Solar Landscape supported the framework because it distinguishes the separate value associated with enrollment, availability, and actual dispatch, while recommending flexibility so that not every resource must receive compensation through all three pathways. For FOM storage, it emphasized a fixed or otherwise calculable, long-term Pathway 2 availability or capacity-reservation payment reflecting opportunity cost and distribution value, with Pathway 3 compensating verified performance when the resource is dispatched. RExChain supports preserving Pathway 1 as a distinct, standalone compensation stream and requests that the Board recognize "readiness aggregation" as an eligible Pathway 1 use case. Uplight asked that Pathway 1 cover enrollment costs, Pathway 2 reserve firm capacity and reflect opportunity costs such as PJM impacts, and Pathway 3 cover dispatch costs plus a performance incentive. DCO applied the pathways to CHP microgrids in the following manner: (1) an upfront $/kW incentive; (2) an annual capacity or availability payment; and (3) performance payments.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the Order does not establish the long-term three-pathway structure. Compensation structures, including fixed enrollment payments and pay-for-performance models, will be evaluated during

the VPP Interim Program to inform the long-term tariff, which is expected to be developed through a petition based on the Grid Flexibility Services workgroup (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) recommendations.

Calibrant, DCO, ModernElectric, Soltage, and Tri-State all asked that pay follow delivered performance, some with fewer payment elements. Calibrant asked for two pathways for batteries, enrollment and performance, without a reservation payment that would limit demand-charge management and arbitrage. ModernElectric recommended an availability payment, a performance payment, and a locational adder capped at avoided cost, and Soltage recommended a two-part structure consisting primarily of an availability payment for reserved capacity and a performance payment for actual delivery during defined hours. To establish the appropriate payment ranges for different grid services, Soltage recommended that the Board consider capacity-resource value, T&D investment deferral or elimination calculated through marginal cost-of-service studies, and PJM energy and ancillary-service market values. DCO recommended an upfront incentive based on estimated qualified peak-load reduction, an annual capacity or availability payment based on calculated or verified peak-load reduction, and performance payments for dispatched services. DCO further stated that CHP resources should not be paid merely for ordinary operation, fuel consumption, or nameplate capacity, but for verified availability, incremental net-load reduction, or another contracted grid service. Tri-State separately recommended monetary incentives based on demand savings and program-supported repayment mechanisms to enable deeper residential retrofits and integrated technology solutions; for commercial customers, it recommended remuneration based on delivered demand savings.

**Staff Response:** Staff thanks the commenters for their feedback on compensation structures and pathways. Staff notes that the EM&V subgroup of the Power Up Working Group to establish future goals, measurements and metrics.

Calibrant, EnergyHub, ev.energy, Logical Buildings, Renew Home, Solar Landscape, and Uplight all opposed or asked to change the uniform seven (7) year enrollment period. EnergyHub stated that it is unenforceable and that storage financing assumes five (5) years. Solar Landscape recommended five (5) years for storage, with compensation locked for the

same period. Uplight asked that the minimum enrollment period should reflect the size of any upfront incentive and expected equipment life, and ev.energy asked for a shorter term for EVs and chargers. Logical Buildings asked that any term come with a disclosed minimum customer value and a penalty-free exit if pay falls. Calibrant opposed a fixed obligation for storage developers and asked for binding fund reservations before energization. Lunar, by contrast, accepted seven years for storage with an upfront incentive option.

**Staff Response:** Staff acknowledges the comments and notes that the Order does not adopt a minimum enrollment period. Enrollment terms for the long-term framework will be addressed as the long-term tariff is developed, informed by VPP Interim Program experience.

EnergyHub, ev.energy, Honeywell, Lunar, Recurve, Solar Landscape, Soltage, Uplight, and Virtual Peaker all supported locational pay, with different approaches in response to the long term proposal. Lunar supported Pathway 2 pay tied to the PSUP value map, but noted that the highest-value circuits are the same ones considered for EDC ownership under § 3.8 and asked that they stay open to third parties. Solar Landscape asked that a locational adder lock in at a complete interconnection application and last at least five (5) years. Virtual Peaker asked that Pathway 3 (Pay-for-Performance Dispatch) Local Event rates be tied to the avoided cost of identified projects. Uplight recommended using broader capacity-need zones or tiers where granular locational values are not initially available, with increasing granularity as PSUP planning and DERMS capabilities mature. Recurve asked to layer locational value or distribution-value incentives onto an existing single customer-facing demand response offer, and Soltage asked the Board to consider urbanization, population density, and general cost-to-serve when assessing how T&D deferral values differ by area within a given EDC territory. EnergyHub and Honeywell cautioned that locational pay should not delay launch and should apply only where the need and its value are documented.

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Order does not set locational payment levels. During the VPP Interim Program, each EDC's dispatch platform must be able to segment resources by location, and quantifying distribution-level grid service values is a program objective, to build the evidence needed for any future procurement of locational distribution benefits.

EnergyHub, ev.energy, Renew Home, Solar Landscape, and Uplight requested simple and predictable compensation within consistent tariff terms. Piclo separately supported establishing baseline terms in the tariff while defining compensation by grid service and use case, and emphasized that Pathway 2 availability payments can provide aggregators predictable revenue sufficient to support customer-acquisition investment. Solar Landscape additionally requested statewide definitions to avoid the development of four materially different EDC frameworks. EnergyHub recommended a fixed seasonal $/kW rate for batteries rather than event-by-event rates and provided illustrative incentives by device type, while Renew Home requested a predictable annual $/kW value. SunStrong separately proposed an EDC-aggregator contractual framework providing a ten-year incentive lock-in from each customer's enrollment date, specified payment structures in the tariff, and publication of annual $/kW values by pathway and, where applicable, by service and utility. It recommended updating the published values annually or biannually for future enrollments while preserving each enrolled customer's committed rate for the balance of the ten-year lock. SunStrong also recommended a minimum EDC-aggregator contract term coextensive with the Interim Program and continued compensation through the transition to the long-term tariff.

> **Staff Response:** Staff acknowledges the commenters' feedback and notes that each EDC will propose its VPP Interim Program incentive structure and ranges in its filing, subject to Board review. Common compensation terms for the long-term framework will be addressed through the long-term tariff process, informed by the Interim Program's evaluation of fixed enrollment and pay-for-performance models.

Calibrant, Electrify America, ev.energy, Honeywell, Logical Buildings, Lunar, Piclo, RExChain, Renew Home, and Solar Landscape all commented on the 70% pass-through floor. Calibrant, Electrify America, and Lunar asked that it not penalize asset owners and third-party owners, with Calibrant asking that a host agreement satisfy the rule where the aggregator owns the battery, and Lunar asking for the requirement to be lowered. Piclo and RExChain preferred an offer-comparison platform, with any floor limited to Pathway 3 (Pay-for-Performance Dispatch). RExChain did not object to a minimum pass-through requirement but requested that the Board retain flexibility in compliance for aggregators offering bundled services. Renew Home asked that any floor apply only to the customer incentive, with a separate aggregator operating budget. Solar Landscape asked the Board to define "aggregator" and recommended that, where the

aggregator acts principally as a market and operational intermediary rather than financing or owning the asset, at least 90% of applicable grid-service compensation flow to the DER owner. If aggregator compensation is instead deducted directly from gross resource value, Solar Landscape recommended that the permitted share be substantially lower than the 30% contemplated by the proposed 70% floor.. ev.energy, Honeywell, and Logical Buildings supported customer protections with disclosure, with any floor set and reviewed using actual cost data.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the Order does not adopt a binding pass-through floor. For the VPP Interim Program, the Order sets a goal of passing through no less than seventy (70) percent of aggregator compensation to participating customers, with tracking rather than a contractual mandate, so that the Board can observe actual practice across EDCs and a range of aggregator business models before setting any binding floor. The Order sets forth definitions of VPP Provider, DER Provider and Site Aggregator.

Calibrant, EnergyHub, ev.energy, Piclo, Uplight, and Voltus all commented on performance standards and the concentration cap. Voltus and ev.energy supported the 80% threshold, applied to aggregations. Calibrant asked the Board to reconcile the two 80% standards and apply the 40% cap sensibly in small territories such as RECO's. EnergyHub asked to remove the cap, and ev.energy asked to phase it in or cap by device type. Piclo asked that penalties attach to committed availability, specifically Pathway 2 (Opportunity Cost and Capacity Reservation) commitments, not enrolled nameplate, and Uplight asked that EDCs propose performance structures rather than fixed 80%, 50%, and 30% thresholds.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the Order does not adopt the performance thresholds or the concentration cap described in the Straw Proposal. For the VPP Interim Program, EDC-aggregator contracts must include a methodology that progressively reduces or eliminates performance payments as response rates decline, and each EDC proposes the specific structure in its filing.

EnergyHub, ev.energy, Honeywell, and Piclo all supported a formal EDC-aggregator dispute resolution process, while Voltus stated that one is not needed. EnergyHub and ev.energy asked for a time-bound process with a neutral reviewer. Piclo asked for one statewide rulebook, a 30-day initial response and 90-day resolution, and qualification recognized in all four

territories. Honeywell asked that any immediate EDC operating restriction be documented and promptly reviewed.

> **Staff Response:** Staff appreciates the commenters' feedback and notes that the Order does not establish a formal EDC-aggregator dispute resolution process for the VPP Interim Program. The need for such a process may be considered as the long-term framework is developed.

Calibrant, Honeywell, Logical Buildings, Lunar, Solar Landscape, Voltus, and WeaveGrid supported service-based anti-duplication rules that preserve compensation for distinct services, obligations, or attributes. Calibrant and Logical Buildings stated that customer bill savings resulting from PLC/5CP management or other tariff-based actions should not be treated as duplicative VPP compensation. Lunar recommended permitting separate distribution-level and wholesale-market payments arising from the same dispatch event when they compensate distinct grid values. Voltus proposed a one-for-one offset only when the same service is compensated twice during the same performance hour. Solar Landscape recommended a service-based framework identifying which GSESP, VPP, CSEP, A796, distribution-service, PJM-related, and other revenue streams and benefits may be combined. It proposed defining duplicate compensation as two payments for the same portion of a resource's capacity providing the same service during the same interval; preserving State deployment-support payments when resources subsequently participate in the VPP or realize PJM-related value; establishing priority and coordination rules for potentially conflicting EDC and PJM obligations; and allowing compensation for distinct services or benefits provided during the same interval. Nexamp supported stacking compatible energy, capacity, ancillary-service, wholesale-market, and targeted distribution value streams, accompanied by transparent rules governing double recovery, dispatch conflicts, performance obligations, metering, and M&V.

Honeywell proposed distinguishing among enablement, availability, performance, hardware or installation, provider or administrative, and locational-adder payments. For each payment, it recommended identifying the payer and recipient, compensated service or attribute, applicable interval, eligibility and availability requirements, authoritative measurement source, performance standard, adjustment and dispute process, and payment-authorizing authority. Honeywell also recommended maintaining a reconciliation record for resources enrolled in multiple pathways. Recurve supported making the prohibition against double compensation across the VPP Interim Program, GSESP Phase 2, existing EDC demand-response

programs, and PJM capacity payments an enforceable and auditable rule implemented through transparent software, while preserving multiple value streams and allowing locational or distribution value to be layered onto an existing customer-facing offer. Recurve separately recommended open, auditable, primarily meter-based M&V standardized across all four EDCs. WeaveGrid recommended reporting the grid service called, the location and timing of the need, the resources dispatched, the measurement method, and whether the resource received compensation from another program or market during the same interval.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that unlocking these multiple compensation streams while guarding against double payment is a long term goal and the Board recognizes there are currently barriers put in place to unlock the true value.

EnergyHub, ev.energy, Honeywell, Logical Buildings, Renew Home, Solar Landscape, Tesla, and Uplight all addressed how VPP resources should reach PJM value. Tesla recommended Peak Shaving Adjustments under PJM Manual 19 as the primary path to capacity value, and asked the Board to separate retail 5CP/PLC language from PJM load forecast reductions. Renew Home asked for a PSA authorizing tariff aligned with A796, and Solar Landscape asked for FOM storage to be treated as load-reducing in PJM forecasts. Uplight stated that PJM capacity and a PSA are alternatives for the same MW, but either can stack with distribution value, and Logical Buildings asked EDCs to disclose the effect on customers' capacity tags. EnergyHub and Honeywell asked that PJM participation stay optional, while ev.energy supported full wholesale access with PJM priority.

**Staff Response:** Staff agrees that a PSA can be an important tool to help lower costs. The VPP Interim Program's focus is on building a program that provides stackable compensation for a variety of grid services, which may have a variety of different performance metrics. Staff notes that the Order directs the EDCs to design dispatch protocols that maximize ratepayer savings and requires a peak shaving goal and the filing of a PSA. Staff will use this Interim Program to determine the best mechanism to achieve both long- and short-term savings and anticipates that EDCs will have feedback on these particular pieces in their Interim report.

ev.energy, Koolbridge, Piclo, and Solar Landscape asked for a small set of performance-based service definitions that can evolve. WeaveGrid

supported compensating all grid services identified in the Straw but recommended adding specificity to the underlying definitions, including defining circuit-level congestion relief at both the feeder and service-transformer levels. ev.energy and Piclo recommended two or three response classes matching the GB pattern of standardized products. Solar Landscape asked that faster tiers be added only where they add system value, and WeaveGrid asked that congestion relief include feeders and service transformers. Koolbridge asked for a recurring review, such as every two years, to add proven capabilities to the eligible resources.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the VPP Interim Program focuses on peak demand reduction during the 5CP hours and other grid stress events. EDCs must provide definitions for a grid event in their filings, which require Board approval. Service definitions for the long-term framework, including distribution services, will be developed with the Grid Flexibility Services workgroup (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) recommendations, informed by the VPP Interim Program data.

Lunar supported the proposed performance ladder, including bonuses above 80% response, penalties below 50%, and hardware-incentive-only status below 30%. It also stated that New Jersey's rate structure provides limited standalone battery economics and recommended designing the GSESP Phase 2 incentive and VPP performance payment as a coordinated economic package. For LMI customers, Lunar recommended upfront incentives meaningfully above the standard incentive level, likely sufficient to cover the full system cost, because the approximately $10,000 to $20,000 cost of a residential battery presents a fundamental barrier to participation. Lunar also recommended modeling LMI customer economics before finalizing the GSESP Phase 2 incentive levels.

**Staff Response:** The VPP Interim Program and the long-term tariff (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) are intended to be compensation for the service provided to the grid. As compensation is determined the Board will also evaluate where additional subsidies are needed to build the market, including how to best address LMI needs.

**xliii. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, NJCCC, SEIA/CCSA/NJSEC, Smart Thermostat Coalition, and VGIC

EEA-NJ, NJCCC, and SEIA/CCSA/NJSEC all addressed the transition timeline and the PSUP. EEA-NJ stated that the timeline may be too ambitious given DERMS, AMI, and interoperability readiness. SEIA/CCSA/NJSEC asked for objective, time-limited milestones, open access on a date certain rather than a DERMS tier, a one-year Interim Program extension if milestones are unmet, and shared VPP and PSUP definitions and grid-need data. NJCCC stated that using PSUP results to direct developers to constrained areas is more cost-effective than utility ownership.

**Staff Response:** Staff notes that the VPP Interim program is designed to build upon the existing demand response programs but notes that the long term VPP tariff, which is already being worked on through the Grid Flex workgroup will provide additional pathways for participation. However, the Interim program can provide opportunities for savings and encourage market development providing the first steps towards the solution called for in EO 1 and EO 2.

The BTM Coalition, SEIA/CCSA/NJSEC, and VGIC supported performance-based compensation under common program terms. ChargEVC separately recommended beginning with a practical performance-based framework that compensates verified capacity availability and delivered grid value, while allowing locational values to be refined over time as hosting-capacity data, circuit constraints, and dispatch history become more transparent. The BTM Coalition recommended a ConnectedSolutions-style program with one $/kW-year rate for all participants, payment to the system owner, reduced pay but no added penalties, and terms that move Interim enrollees to a pay-for-performance Pathway 3 after five years. ChargEVC recommended pay for verified availability and grid value, based on avoided capacity, distribution, and transmission costs. VGIC supported the three pathways as suited to EV charging. SEIA/CCSA/NJSEC asked that Pathway 1 be set after performance pay, opposed aggregator-specific Pathway 1 amounts, and asked that clawbacks be limited.

**Staff Response:** Staff thanks the commenters for their feedback and notes that many of the decisions regarding the long-term tariff will be determined in future Grid Mod proceedings *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for*

*Aggregated DER Participation in New Jersey's Modernized Electric Grid)*. Staff also notes that the EDCs must include a transition plan for customers into the long-term tariff.

SEIA/CCSA/NJSEC and the Smart Thermostat Coalition opposed a fixed customer pass-through floor. Advanced Energy United took a conditional position, stating that a pass-through requirement may be appropriate for customer-owned DERs where an OEM or another operator retains a portion of the payment, but recommended that any floor apply only to customer-owned assets.. SEIA/CCSA/NJSEC stated that most BTM batteries are third-party owned, so the owner carries the risk and passes value through lower lease rates or payments. Thus, the pass-through floor could limit third-party owned offerings and thereby limit customer choice. The Smart Thermostat Coalition asked that payments flow to the aggregator, with allocation subject to disclosure.

**Staff Response:** Staff thanks commenters for their feedback and notes that in the Order the pass-through is non-binding but the data will be collected to ensure that future tariffs are reflective of the true costs of the providing the service to the grid. In order for thereto be an incentive to pass to a customer there would have to be a customer owned device.

ChargEVC, SEIA/CCSA/NJSEC, and VGIC all addressed PJM value and service definitions. ChargEVC recommended focusing the near-term VPP design on the New Jersey distribution market without delaying implementation for prospective PJM programs, while preserving the ability to establish a mechanism that credits any realized transmission and capacity value to ratepayers. SEIA/CCSA/NJSEC asked that resources earn both retail and PJM value unless paid twice fin the same interval, noting that a PSA approach bars wholesale participation. ChargEVC recommended focusing the near-term VPP design on the New Jersey distribution market without delaying implementation for prospective PJM programs, while preserving the ability to establish a mechanism that credits any realized transmission and capacity value to ratepayers. SEIA/CCSA/NJSEC asked that resources earn both retail and PJM value unless paid twice for the same service in the same interval, noting that a PSA approach bars wholesale participation. VGIC asked for a near-term focus on PSA savings, with PJM participation optional. ChargEVC and SEIA/CCSA/NJSEC both asked to start with a few clearly defined services, such as peak reduction and local distribution support.

**Staff Response:** Staff thanks the commenters for the comment and notes that many of the decisions regarding the long-term tariff will be

determined in future Grid Mod proceedings *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)*.

Advanced Energy United and SEIA/CCSA/NJSEC both sought stronger open-access protections, although through different mechanisms. In connection with its proposed Interim Program "walk-up" tariff for OEMs, TPOs, and DERMS providers, Advanced Energy United recommended allowing any qualified participant to connect its edge DERMS directly to the EDC's Grid DERMS under published, non-proprietary specifications. SEIA/CCSA/NJSEC requested statewide contracts, firm EDC response deadlines, uniform data-access standards, continuity of compensation, and an expedited dispute-resolution process with interim relief when enrollment or payment is at risk. It further recommended that, when AMI data are used to validate performance or calculate payments, EDCs make the necessary data available to customers and their authorized OEMs, TPOs, or aggregators as close to real time as possible. Where device-level telemetry is used to measure performance, it recommended that AMI data remain accessible, although not necessarily subject to the same service level.

**Staff Response:** Staff thanks the commenters for their feedback and notes that many of the decisions regarding the long-term tariff will be determined in future Grid Mod proceedings *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)*. Staff also notes that the EDCs must include a transition plan for customers into the long-term tariff.

**xliv. Advocacy Groups**

Commenter(s) Referenced in This Summary: ACEEE, Evergreen Action and EDF, NJEJA, New Jersey LCV, Sierra Club, and Vote Solar

ACEEE, Evergreen Action and EDF, and New Jersey LCV all asked that pay reflect verified, local grid value. ACEEE recommended paying for capacity delivered in critical local hours, credited only beyond what rates and other programs already pay. Evergreen Action and EDF supported the three pathways with enrollment pay by device class, seasonal rates, a statewide rate plus a constrained-area adder until PSUP data is ready, a stated floor for each pathway, a standard "VPP facts label," and three-year (thermostats and EV chargers) or five-year (batteries) commitments instead of seven. New Jersey LCV asked for clear Board guidance on pay

that can be locked in for multiple years, and for a focus on the New Jersey distribution market rather than waiting on FERC Order No. 2222.

> **Staff Response:** Staff thanks the commenters for their feedback and notes that the EM&V subgroup of the Power Up Working Group to establish future goals, measurements and metrics, this includes how to fully capture all savings unlocked by VPPs through a variety of grid services.

Evergreen Action and EDF, NJEJA, and Vote Solar all supported a minimum pass-through requirement. Evergreen Action and EDF supported both the 70% floor and an offer-comparison platform, reviewed with program data. NJEJA recommended passing at least 50% of net revenue to customers as a bill credit, with 25% directed to high-need communities and a 10% "social multiplier." Vote Solar recommended that the Board examine how the floor applies to FOM subscription models and asked for a 30% pass-through to residents for FOM resources in overburdened communities. It also recommended a public offer-comparison platform.

> **Staff Response:** Staff thanks commenters for their feedback. Within the PowerUp NJ Order, the pass-through is non-binding but the data will be collected to ensure that future tariffs are reflective of the true costs of the providing the service to the grid. How tariffs will be implemented, designed and communicated will be addressed in future proceedings.

Evergreen Action and EDF asked for a firm July 1, 2029 outside date for the long-term tariff, a 180-day PSUP review, and Grid DERMS deadlines of Tier 1 by July 1, 2027, Tier 2 by July 1, 2028, and Tier 3 by July 1, 2029. It also asked that dispatch-priority rules apply only when obligations conflict, that withheld incentives return to ratepayers, that the 40% cap be waived in small territories, and that operational disputes be resolved within 15 business days.

> **Staff Response:** Staff thanks the commenters for this feedback and notes that many of the decisions regarding Grid DERMS and the long-term tariff will be determined in future Grid Mod proceedings *(*BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)*.

Sierra Club and Vote Solar both asked that equity be built into the long-term framework. Sierra Club urged the Board to finalize the long-term

program quickly and incorporate an explicit equity floor, LMI enrollment targets, and compensation for hosting equipment into the tariff. It also recommended identifying priority areas for DER and storage deployment based on OBC designations, LMI concentration, documented electricity-disconnection and energy-insecurity rates, high energy burdens, and distribution-level grid-stress indicators and bottlenecks. Sierra Club proposed providing those priority areas with benefits such as prioritized interconnection, expedited permitting, and additional financial compensation. Vote Solar asked that PSUP-VPP coordination flag worst-performing circuits serving overburdened communities for higher locational values and recommended locational procurements for FOM resources.

Staff Response: Staff acknowledges the commenters' feedback and notes that equity and LMI access are among the market support structures the Order anticipates addressing through the PowerUp NJ Working Group over the next 30 months.

**xlv. Program Implementers and Administrators**

Commenter(s) Referenced in This Summary: Ampion, Energy Solutions, Michaels Energy, and Power TakeOff

Ampion supported using both the proposed 70% pass-through floor and a public offer-comparison platform but stated that a licensed settlement market would be necessary to make the floor auditable and enforceable at scale. It proposed that VSAs verify and document actual customer pass-through against settled payments and provide standardized, audited information to the comparison platform. Ampion also identified the VSA as the appropriate entity to administer the revenue-stacking disclosure requirement because it could observe both retail and PJM revenue streams associated with the same DER.

**Staff Response:** Staff thanks the commenter for this feedback and notes that the future EM&V subgroup of the future PowerUp NJ Working Group to establish future goals, measurements and metrics.

Energy Solutions asked the Board to set consistent metrics, measurement methods, and valuation frameworks early, and supported stacking where each benefit is separately verified. Energy Solutions specified that the Board should establish clear rules so that the same performance is not

compensated twice. It also advocated for the preservation of pathways for resources to participate in both PJM and EDC programs where allowed.

> **Staff Response:** Staff thanks the commenter for this feedback and notes that the Straw Order indicated that unlocking these multiple compensation streams while guarding against double payment is a long term goal, in the short term Staff acknowledges that there are barriers to this and is seeking to quantify those barriersStaff also notes that the Order provides details on how to avoid double counting during the Interim Program.

Michaels Energy supported the three pathways adapted to C&I resources. It asked that Pathway 1 (Enrollment) cover customer recruitment, site screening, feasibility engineering, baseline development, controls integration, site gateways, metering, commissioning, and documentation. Michaels Energy further asserted that a clear pathway should be established to make hardware incentives available to thermal energy storage and refrigeration systems. It also advocated for transferable and prorated multi-year obligations, and argued that Pathway 2 (Opportunity Cost and Capacity Reservation) should be defined by reserve capacity. Michaels Energy further stated that Pathway 2 should recognize thermal storage reserves and their pre-charge energy through a tariff.

> **Staff Response:** Staff thanks the commenter for this feedback and notes that the Order does not establish the long-term pathway structure. During the VPP Interim Program, C&I resources may participate under the technology-neutral eligibility rules, and each EDC proposes its incentive structure in its filing.

Power TakeOff recommended that a centralized, impartial AMI data analysis provider contracted by the EDC perform functions that do not require customer-facing competition, including customer identification and recruitment, enrollment verification, AMI-based event-performance measurement, and M&V. For Pathway 3 (Pay-for-Performance Dispatch), it proposed that this provider calculate verified demand reductions against the applicable AMI-based baseline, reducing self-dealing concerns and potentially using meter-data disaggregation to address premises with multiple participating devices. Power TakeOff stated that this structure would preserve the three-pathway compensation framework but could modify Pathway 1 (Enrollment) payments because some recruitment responsibilities would shift from aggregators to the AMI data analysis provider. It further suggested that aggregators might not require direct access to customer AMI data under this model, provided the provider's

contract includes safeguards against preferential access, cross-subsidization, and misuse of confidential customer or grid data.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order allows each EDC to deliver its program through contracted implementation contractors, and that verification of program savings will be performed by an independent evaluator retained by the Board.

### xlvi. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

Base Power and NRG both asked for flexible use of the three pathways. NRG supported the framework but cautioned against rigid structures, and Base Power asked that the pathways be severable so a resource can enroll only in Pathway 3 (Pay-for-Performance Dispatch).

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Order does not establish the long-term pathway structure. The long-term tariff will be developed through a separate process, informed by the VPP Interim Program's evaluation of different compensation structures.

Base Power asked the Board not to apply the 70% floor to third-party suppliers or owners, relying instead on disclosure and an enhanced NJ Power Switch platform. It asked to remove the 40% cap, extend non-discrimination rules to supplier-served load, and treat demand-side value, such as lower peak load contributions, as a core part of the long-term value stack.

**Staff Response:** Staff acknowledges the commenter's feedback on the 70% floor and notes that the Order does not adopt a binding pass-through floor or the concentration cap described in the Straw Proposal. For the VPP Interim Program, the seventy (70) percent pass-through is a goal with tracking rather than a mandate. Non-discrimination rules and the long-term value stack will be addressed as the long-term framework is developed.

NRG asked that retention periods vary by technology, incentive, and asset life, and that locational pay start statewide and grow with data. It also asked that the VPP not depend on DERMS completion and that DER

aggregations be able to participate in PJM markets, with limits only for specific reliability or safety constraints.

**Staff Response:** Staff thanks the commenter for this feedback and notes that the Straw Order indicated that unlocking these multiple compensation streams while guarding against double payment is a long-term goal.

### xlvii. Financial Services

Commenter(s) Referenced in This Summary: Syntropic

Syntropic supported the three-pathway structure and the seven-year period, stating that both make revenue easier to finance. It supported the 70% floor but asked the Board to clarify that a customer's separate, voluntary loan repayment to a lender does not reduce the aggregator's pass-through. Syntropic also recommended that the Board expand the incentive base to include the cost of making a home capable of safely hosting the storage system, satisfied either by a traditional service upgrade or by a code-compliant Power Control System or equivalent, plus the cost of power storage equipment.

**Staff Response:** Staff thanks the commenter for this feedback and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The program is designed as a compensation for services to the grid not a hardware incentive.

### xlviii. Individuals and Academic Institutions

Commenter(s) Referenced in This Summary: Cammie Croft, Michael Winka, and UDelaware

Cammie Croft asked that, for third-party-owned assets, the enrollment commitment and any clawback attach to the owner-operator and the premises rather than the household.

**Staff Response:** The Order calls for transition plans to be developed and proposed by the EDCs in their filings to ensure that a seamless transition occurs both to the VPP Interim program and to the long-term tariff.

Michael Winka recommended developing a long-term, performance-based model under a utility Distribution Service Operator ("DSO") that would

phase out upfront DER incentives and transition toward a more competitive market providing payments for grid services. He recommended limiting Pathway 1 payments to the Interim Program and testing Pathway 2 seasonal-capacity payments through sandbox pilots during the Interim Program. Winka also recommended testing locational performance payments through Interim Program sandbox pilots using hosting-capacity maps until more detailed PSUP baseline information becomes available. For the long-term program, he proposed separate customer classes and associated tariffs based on resource configuration and participation in NEM, the DSO VPP, and RTO markets.

**Staff Response:** Staff thanks the commenter for this feedback and notes that many of the recommendations regarding the long-term tariff will be determined in future proceedings (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*).

UDelaware asked for time-of-day rates for BTM storage, including an option for NEM with particular regard to providing PJM services. For EDC services, UDelaware recommended that the Board encourage the development of a net billing tariff where charging and discharging through the premises meter is billed or credited at the time-of-use rate, and the value of energy is summed. It further stated that a utility could run a sandbox with the needed VPP functions by mid-2027. UDelaware also asked the Board to acknowledge FERC's definition in Order No. 2222 that two grid services meeting different needs do not constitute double counting, and to recognize that PJM response services can be metered by a device meter in an inverter or EVSE while energy transactions are reconciled through the premises meter.

**Staff Response:** Staff thanks the commenters for this feedback and notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. Staff notes that many of the recommendations regarding future tariffs will be determine in future Grid Mod proceedings (BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid). For double counting, the Order directs Staff and the EDCs to coordinate the PowerUp NJ Programs with the Board's parallel proceedings to prevent duplicative compensation for the same service. Rules for stacking distinct services, including metering for PJM services, will be addressed as the long-term tariff is developed. Staff also notes

that the Straw indicated the need for several of the issues raised to be addressed as part of net metering reform.

# 7. Cross-Program Coordination

***Straw Proposal section(s):*** *§ 3.2, § 4.1–4.5, § 4.7–4.9*

**Summary of Comments:** Commenters agreed that the VPP must be developed in step with Grid Flexibility Services, the Proactive System Upgrade Plan, GSESP Phase 2, the Triennium energy efficiency (EE) programs, net metering (NEM), time-of-use (TOU) rates, and EV programs, and many asked for one set of definitions and data rules across these proceedings. On GSESP Phase 2, most asked that Phase 2 storage be able to enroll in the VPP with the aggregator of the owner's choice. Some asked that Phase 2 provide only the deployment incentive, with dispatch pay through the VPP, while Rate Counsel and NJEJA asked for a forfeiture or a one-for-one offset. Most supported moving Triennium DR programs into the VPP, but several opposed requiring VPP enrollment as a condition of EE hardware incentives. Most stated that NEM credits for exported energy and VPP pay for grid services are different, while RECO and Rate Counsel opposed paying both for the same service. Commenters generally favored simple, technology-neutral TOU rates that complement VPP pay, supported public fleets joining under common rules, and asked for a broad VPP Working Group with a set meeting schedule. Comments on revenue stacking and PJM participation are summarized in Section 6.

### xlix. Utilities and Utilities Association

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, RECO, and NJNG

ACE, JCP&L, NJUA, PSE&G, and RECO all asked that the VPP be developed in step with related proceedings, including GridFlex, the PSUP, GSESP, the Utility Business Model Study, EE programs, and NEM reform, to avoid conflicting or duplicate requirements. ACE supported the proposed GridFlex sequencing. RECO asked for a shared roadmap, issue log, and dependency tracker across proceedings. JCP&L asked for common rules on customer consent, data access, dispatch priority, measurement, anti-double-counting, and cost recovery.

> **Staff Response:** The Straw clearly outlines the need to coordinate each of those proceedings into the planning for the Interim and long term VPP design.

ACE, PSE&G, and RECO all supported coordinating the VPP with GSESP Phase 2. ACE asked for aligned registration, telemetry, dispatch, and

measurement rules, with storage able to join both programs without double compensation. RECO asked that specifications be coordinated to prevent conflicts. PSE&G asked that battery performance incentives be paid through the VPP rather than a separate GSESP mechanism, that Phase 2 participants meet aggregation, cybersecurity, metering, telemetry, and dispatch-priority requirements, and for clarity on how Phase 2 resources will be paid, noting that the EDCs had not yet seen the revised Phase 2 rules.

> **Staff Response:** The Order includes both the VPP Interim program and the GSESP Phase 2 for a coordinated program.

ACE, NJNG, PSE&G, and RECO all supported moving Triennium DR programs into the VPP with coordinated EE programs. PSE&G asked that Triennium 2.5 fund current programs until they move, and opposed requiring customers who receive EE incentives for connected devices to enroll in the VPP, noting that only 19% of its Marketplace thermostat buyers chose FlexPower despite a $50–75 reward. RECO asked that VPP-related funding, including labor, incentives, and hardware incentive costs, move from the Triennium into the VPP. ACE asked for aligned enrollment, communications, and M&V, with rules against double compensation. NJNG asked that EE be treated as complementary to the VPP.

> **Staff Response:** Staff thanks the commenters for their feedback and notes that the EDC-run VPP Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff. The Order and Straw reference the Triennium budgets as part of the basis for the recommended budget for these programs.

ACE, PSE&G, and RECO differed on the incorporation of NEM into the VPP Interim Program. ACE opposed reducing VPP pay for NEM customers, stating that NEM pays for energy exports (kWh) and the VPP for grid services (kW), and recommended aligning NEM export value with VPP grid-service value over time. RECO stated that no customer should receive both NEM and VPP pay for the same service in the same period. PSE&G asked the Board to clarify or reform NEM, because batteries are not Class

I renewable resources and solar-plus-storage customers could lose NEM benefits by exporting from storage.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that, for now, customers with solar-only systems on a NEM tariff cannot include their solar systems in the VPP Interim Program, to avoid paying twice for the same value. Customers with solar plus storage, and other BTM residential and small commercial batteries, can participate through Block 1, not the VPP Interim Program. NEM and Block 1 compensate different functions: NEM compensates eligible exports from the customer-generator, while Block 1 compensates verified battery discharge during dispatch events. On PSE&G's concern, the Order allows a solar-plus-storage system to export and receive NEM credit where equipment controls or operating software ensure that exported battery energy was charged only from the paired solar facility.

ACE, PSE&G, and RECO all cautioned against technology-specific TOU rates. ACE recommended consistent system-wide peak periods, with VPP pay limited to measurable services beyond what TOU rates already reward, and suggested that VPP participation could require TOU enrollment. RECO favored optional, technology-agnostic, revenue-neutral rates, and stated that a TOU customer should not also receive VPP pay or NEM, but that VPP pay should at least equal the TOU benefit. PSE&G asked for simple rules that protect customers from bill impacts of VPP events.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the Order does not establish new TOU rates. Attachment A requires each EDC's baseline methodology to account for load changes caused by time-of-use rates or other programs, so that only reductions caused by VPP dispatch are counted.

ACE, PSE&G, and RECO all addressed EVs and public-sector assets. ACE asked the Board to approve a new Smart Charge Management (managed EV charging) offering in the Interim Program, citing the Maryland program run by Delmarva Power, Pepco, and BGE, with more than 11,000 enrolled devices and about $300 per EV per year in avoided distribution costs. It also supported phased participation of NJ Transit, school buses, and other public facilities once they show reliable performance. RECO recommended passive managed charging for public fleets, similar to Orange & Rockland's Smart Charge Commercial program in New York, and V2G pilots before full deployment. PSE&G requested that EDCs have flexibility to decide how to include public-sector assets.

**Staff Response:** Staff appreciates the commenters' feedback and notes that managed EV charging is among the existing customer devices the VPP Interim Program builds on, and each EDC proposes its eligible customer classes, DER types, and sub-programs in its filing. Public-sector resources may participate under the same technology-neutral eligibility rules, while V2G compensation will be considered in the long-term framework established via the Grid Flexibility Services proceeding (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*).

ACE, NJNG, PSE&G, and RECO all supported a VPP Working Group. ACE asked that it focus on technical standards, telemetry, M&V, data exchange, and cybersecurity, supplemented by technical workshops. PSE&G recommended a structure like the EE utility-Staff group, with separate groups for the Interim Program and the long-term program. RECO asked that the meeting schedule follow program milestones and that more subject-matter experts be allowed to attend. NJNG asked that gas distribution companies be allowed to participate.

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Order establishes the PowerUp NJ Working Group and a variety of subgroups. Staff intends for the working group to be an avenue for further discussion between Board Staff, the EDCs, the Division of Rate Counsel, and other interested stakeholders.

### I. Division of Rate Counsel

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel stated that the Straw Proposal treats coordination as administrative and asked the Board to evaluate total ratepayer exposure across GSESP, the VPP, the Triennium, Grid Modernization, net metering, and other programs before new commitments. It recommended a resource inventory, a resource-level compensation ledger, a cumulative bill-impact analysis, and an issue-and-docket map. It opposed paying a GSESP Phase 2 storage resource through the VPP as well; if both are allowed, the resource should forfeit its Phase 2 incentive or offset all overlapping support one-for-one.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order prohibits simultaneous participation in the VPP Interim Program and Block 1, and that load reduction compensated

under Block 1 or a Triennium program may not be counted toward the VPP Interim target. Each EDC must also provide a cumulative rate and bill impact summary for all approved and proposed programs and describe the safeguards that prevent double compensation across NEM, Block 1, other storage programs, and PJM markets.

Rate Counsel agreed that existing demand response (DR) offerings should migrate to the VPP but warned against relabeling existing capability as new. It asked EDCs to file an auditable baseline before any migrated resource counts toward a target or receives new pay, and opposed using migration to rate-base program costs. It recommended minimizing hardware incentives and, where they are justified, requiring VPP enrollment, suggesting a five-year minimum.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order requires each EDC to describe how its Triennium 2 DR programs will transition into the VPP Interim Program, and that its first PSA plan must be supported by the most recent measured event performance of those programs. Load reduction compensated under a Triennium program may not also be counted toward the VPP Interim target. Program costs are treated as Operating Expense, and capital treatment is available only where the Board expressly approves a demonstrated need. The Order does not require VPP enrollment as a condition of hardware incentives offered under other programs.

Rate Counsel stated that GridFlex, PSUP, and DERMS work should not become separate cost-recovery paths ahead of a proven need, and that the GridFlex sequencing does not prevent conflicts between distribution and system-wide compensation. It recommended that each VPP designate itself as system-wide or location-specific, and that a distribution benefit count only when a project is removed or deferred in the EDC's capital plan. It doubted EDCs would use DERs to cut capital spending and recommended case-by-case review of non-wires alternatives through the PSUP.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order treats VPP Interim Program costs as Operating Expense, and any capital investment must be described and justified in the EDC's petition and expressly approved by the Board. Each EDC must support any avoided distribution value it claims with its methodology, unit value, and sources, and must describe how VPP grid services will be incorporated into distribution planning, including coordination with its Proactive System Upgrade Plan (see BPU Docket

No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*) filing. Specifically, PSUP filings are not cost recovery mechanisms for EDCs and Board-approved PSUP filings do not infer prudence or cost recovery for future investments.

Rate Counsel recommended paying EV customers only for response beyond what their rates or managed charging already produce. EV services should not share one compensation stream, fleets should pay for upgrades they cause, and V2G should be paid on verified net export. For storage, it recommended removing event exports from NEM credit and paying them through the VPP, and asked the Board to finish NEM tariff work before setting long-term export payments.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that BTM residential and small commercial batteries, including solar plus storage, participate through Block 1, not the VPP Interim Program. Under the Order, a solar-plus-storage system may receive NEM credit for battery exports only where equipment controls or operating software ensure that the exported energy was charged from the paired solar facility, so NEM credit is not paid for grid-charged energy. The Order does not create a separate export rate for standalone storage; until the Board approves another applicable tariff, its compensation for dispatch remains the Block 1 performance payment. For EVs, each EDC's baseline must account for load changes caused by TOU rates or other programs, so that only reductions caused by VPP dispatch are counted. V2G compensation will be considered in the long-term framework, and the NEM tariff reform is currently underway.

Rate Counsel supported time-differentiated pricing, but not technology-specific, TOU rates and recommended peak-time rebates and demand charges tied to PJM peaks. It stated that cost-reflective rates could achieve much of the load shifting the VPP would buy, so VPP payments should cover only added response. It viewed dispatch conflicts with TOU as unlikely. On public entities, it questioned more ratepayer funding for NJ Transit and stated that public participants should be competitively procured where practical, paid on performance, and net of other public funding.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that TOU rates can play an important role in shifting load but are not the same as a VPP, and that rate design is outside the scope of this Order. Attachment A requires each EDC's baseline methodology to

account for load changes caused by TOU rates or other programs, so that only reductions caused by VPP dispatch are counted. Public-sector participants are subject to the same eligibility, performance-based contracting, and anti-double-counting requirements as other participants.

Rate Counsel recommended monthly VPP Working Group meetings before launch, with standing reviews of operational data and related proceedings. It asked for a written charter with balanced membership, public materials, and recorded non-consensus positions, and stated that the group should remain advisory and not set compensation, cost allocation, or budgets.

**Staff Response:** Staff appreciates the commenter's feedback and notes that the Order establishes the PowerUp NJ Working Group to facilitate collaboration among the Board, the EDCs, Rate Counsel, and relevant stakeholders, with subgroups such as Marketing, EM&V, and benefit-cost analysis. Subgroup recommendations, such as those of the EM&V subgroup, are submitted to Staff for approval. Staff will consider these suggestions on meeting frequency, charter, and public materials as the Working Group is organized.

**li. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, Edgeli, Electrify America, EnergyHub, ev.energy, Honeywell, Logical Buildings, ModernElectric, Nexamp, PACE AI, Piclo, Renew Home, RExChain, Solar Landscape, Soltage, Tesla, Tri-State, Uplight, Voltus, and WeaveGrid

DCO, Edgeli, and Honeywell all asked for common rules across the VPP, GridFlex, PSUP, and storage proceedings. DCO asked for one participation pathway, with the VPP tariff setting common definitions, qualification, data, and settlement rules, GridFlex defining distribution services and locational values, and the PSUP showing where they are needed. Honeywell asked for a common glossary and change log, with later changes applied going forward and with transition treatment for enrolled resources. Edgeli asked that one data schema serve the VPP, PSUP, and GridFlex proceedings.

**Staff Response:** Staff notes that the VPP Straw indicated that there will continue to be strong coordination with each of those dockets.

Calibrant, EnergyHub, ev.energy, Honeywell, ModernElectric, Nexamp, Piclo, Solar Landscape, and Voltus all addressed GSESP Phase 2. Most asked that Phase 2 storage be able to enroll in the VPP. EnergyHub asked the Board to confirm that Phase 2 enrollment does not preclude VPP participation, and ev.energy and Piclo recommended that Phase 2 incentive terms explicitly preserve the asset owner's right to designate any licenses aggregator, and that Phase 2 assets be registered in the same DER Registry used for VPP purposes. Calibrant asked that Phase 2 be only a deployment incentive, with dispatch pay through the VPP, and ModernElectric and Honeywell asked that installation incentives stay separate from VPP pay while new equipment be VPP-compatible. Solar Landscape asked that Phase 2 resources be aggregation-compatible without being tied to an aggregator or EDC contractor. Voltus asked the Board to accelerate Phase 2, with a $200/kWh incentive that transitions to performance pay. Nexamp supported using Phase 2 as the main pathway for distributed FOM storage through a walk-up, open-access tariff, with the VPP as a complementary revenue source.

> **Staff Response:** Staff notes that this Order contains the MFRs for both the VPP Interim Program and the GSESP Block 1 residential charger program. This Order is just the first step in building out a robust market for storage and grid services.

ev.energy, Renew Home, and Uplight addressed coordination between the Triennium and the VPP framework. ev.energy and Renew Home both supported moving Triennium DR into the VPP, with Renew Home asking that existing participants not have to re-enroll and that thermostat EE incentives remain available. ev.energy asked the Board to clarify which hardware incentives will require VPP enrollment and which will offer an optional adder. Uplight asked the Board not to require VPP enrollment as a universal condition of EE hardware incentives. Tri-State recommended a whole-home evaluation that combines EE and VPP enrollment.

> **Staff Response:** The VPP Interim program outlined in this Order is designed to compensate customers for the service they provide to the grid, EE and EV proceeding provide hardware incentives as appropriate.

EnergyHub, ev.energy, Honeywell, RExChain, Tesla, and Voltus all addressed NEM coordination. EnergyHub asked the Board to delay the NEM successor proceeding until the Interim Program and GSESP are established. ev.energy asked EDCs to separate capacity and energy value in VPP tariffs, and Honeywell stated that NEM credits and VPP pay may

be paid together when they buy distinct services. RExChain asked the Board to clarify that SREC/REC compensation and VPP compensation are separate, non-conflicting value streams that should not be treated as "double counting." Voltus recommended restructuring NEM like New York's Value of Distributed Energy Resources tariff, so customers can opt out of individual value streams. Tesla asked the Board to work with PJM to include NEM-connected batteries under Peak Shaving Adjustment mechanisms without delaying the Interim Program.

**Staff Response:** Staff thanks the commenters for their feedback and notes that, for now, customers with solar-only systems on a NEM tariff cannot include their solar systems in the VPP Interim Program, to avoid paying twice for the same value. Customers with solar plus storage, and other BTM residential and small commercial batteries, can participate through Block 1. NEM compensates eligible exports from the customer-generator, while Block 1 compensates verified battery discharge during dispatch events. NEM reform remains under consideration in a separate proceeding

ev.energy, Logical Buildings, PACE AI, Solar Landscape, Soltage, and WeaveGrid addressed the relationship between retail rate design, including TOU and dynamic pricing, and VPP participation or compensation. ev.energy asked that baselines account for TOU-induced load shifting and that technology-specific TOU rates be limited to a few categories, such as an EV overnight rate. WeaveGrid recommended coordinating, while maintaining a distinction between, cost-reflective rates and active VPP dispatch: rates can provide broad customer-facing price signals, while active dispatch provides the operational control and performance verification needed for specific system or distribution services. Logical Buildings asked EDCs to propose a standard rate option for aggregated flexible load, such as multifamily portfolios. Soltage suggested that EDCs revise the tariff to make off-peaking charging more economical for batteries that support peak events, including waived off-peak demand charges. Solar Landscape recommended limiting any interim double-payment restriction to compensation for the same service provided by the same resource during the same interval, with an offset or settlement adjustment applied only to the duplicative component. For the long-term program, it recommended a service-based methodology identifying which combinations of VPP, rate-based, State-program, and wholesale compensation may be stacked. PACE AI recommended incorporating the lessons learned from the California Energy Commission's CalFlexHub work on dynamic price signals into the work plan addressed in the Straw.

**Staff Response:** As noted in the VPP Straw, TOU can play an important role in shifting load, but are not the same as a VPP. Staff notes that many of the decisions regarding the long- term tariff will be determined in future Grid Mod proceedings *(BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)*.

Electrify America and ev.energy both supported adding public-sector fleets to the VPP. Electrify America asked that pilot resources be set up for VPP enrollment from the start, with telemetry aligned to VPP standards. ev.energy supported coordination with NJ Transit and the school bus V2G pilots, open to competitive aggregators, with pilot results reported publicly.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that public-sector resources, including fleet charging, may participate in the VPP Interim Program under the same technology-neutral eligibility rules as other resources, and each EDC proposes its eligible customer classes and DER types in its filing. V2G compensation will be considered in the long-term framework.

Edgeli, Electrify America, ev.energy, Honeywell, Logical Buildings, PACE AI, Piclo, Renew Home, and Solar Landscape all asked for a broad VPP Working Group. ev.energy asked for a guaranteed aggregator seat and quarterly meetings tied to milestones, while Electrify America asked for monthly meetings with a standing agenda. Honeywell asked for a written charter with deliverables, an unresolved-issues log, and a sunset date. Piclo asked that membership explicitly include independent market-platform operators and out-of-state and international practitioners. Others asked to include non-aggregator technology providers (Edgeli), project-finance experts (Solar Landscape), residents and multifamily owners (Logical Buildings), the public (Renew Home), and the ESCO and HVAC firms (PACE AI).

**Staff Response:** Staff thanks the commenters for their feedback and notes that the Order establishes the PowerUp NJ Working Group to facilitate collaboration among the Board, the EDCs, Rate Counsel, and relevant stakeholders, with subgroups organized to address specific workstreams. Staff will consider these suggestions on membership, meeting frequency, and structure as the Working Group is organized.

**Iii. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, NJCCC, SEIA/CCSA/NJSEC, Smart Thermostat Coalition, and VGIC

Advanced Energy United, the BTM Coalition, NJCCC, and SEIA/CCSA/NJSEC all addressed GSESP Phase 2. Advanced Energy United recommended a clear separation of program functions: GSESP would provide deployment incentives for BTM and FOM storage, while a single VPP program would compensate storage for the grid services it provides. The BTM Coalition similarly opposed establishing separate pay-for-performance programs for new batteries under GSESP and existing batteries under the Interim VPP. It recommended one ConnectedSolutions-style, event-based pathway for both new and existing BTM storage under the VPP umbrella, even if technically administered through GSESP, with systems receiving GSESP deployment incentives required to enroll. If that pathway resides in the Interim VPP, the BTM Coalition recommended using GSESP to fill remaining revenue gaps or support additional storage deployment through an upfront incentive or fixed payments over a small number of years. SEIA/CCSA/NJSEC asked that Phase 2 resources enter the VPP as the performance requirement of the GSESP payment, with customers retaining data portability, transferable enrollment, choice of aggregator, and standardized device registration. SEIA/CCSA/NJSEC further suggested that the Interim VPP should disallow exclusive EDC control, proprietary interfaces, long lock-in periods, and clawbacks for switching aggregators. NJCCC asked that the place of FOM storage be settled in GSESP Phase 2 if not in the VPP.

> **Staff Response:** Staff thanks the commenters for their feedback and notes that the Straw indicates that unlocking these multiple compensation streams while guarding against double payment is a long-term goal. Staff also notes that the Straw contemplates EE and EV hardware incentives remain within those proceedings and are not considering double payment, the Straw also suggests looking at ways to encourage VPP participating with incentivized hardware. This Order also includes the MFRs for GSESP Block 1.

EEA-NJ, SEIA/CCSA/NJSEC, and the Smart Thermostat Coalition supported coordinating Triennium DR with the VPP while keeping EE hardware incentives in place. The Smart Thermostat Coalition asked the Board to confirm that thermostat EE incentives remain available through the EE portfolios. SEIA/CCSA/NJSEC recommended that new participants enter the VPP framework once it is ready, while existing Triennium

commitments should be honored or converted voluntarily without loss of benefits. It also requested consistent eligibility, communications, consent, and measurement rules, with hardware funded through the Triennium or GSESP and the VPP paying for availability and delivered grid services, subject to clear rules preventing duplicate payment.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the Order directs the EDCs to use their Triennium 2 DR programs as the foundation of the VPP Interim Program, while hardware incentives continue to be offered through other Board-approved programs, provided they do not duplicate VPP compensation. The Order also provides that participants may move between PowerUp NJ sub-programs and future programs without penalty.

The BTM Coalition, SEIA/CCSA/NJSEC, and VGIC all stated that NEM credits and VPP pay compensate different services. The BTM Coalition stated that NEM pays for surplus solar the utility does not control, while VPP pay is for dispatch. BTM Coalition asked that the VPP launch before an NEM successor, targeting 2028, with solar-plus-storage customers able to enroll in both. SEIA/CCSA/NJSEC asked that NEM continue for exported energy, with VPP pay for availability, dispatch, capacity, or locational service. VGIC asked that NEM customers be able to add bidirectional EV charging without losing NEM credits.

**Staff Response:** Staff thanks the commenters for their feedback and notes that, for now, customers with solar-only systems on a NEM tariff cannot include their solar systems in the VPP Interim Program, to avoid paying twice for the same value. Customers with solar plus storage, and other BTM residential and small commercial batteries, can participate through Block 1. NEM compensates eligible exports from the customer-generator, while Block 1 compensates verified battery discharge during dispatch events. NEM reform remains under consideration in a separate proceeding, and V2G compensation, including for bidirectional EV charging, will be considered in the long-term framework.

Advanced Energy United, SEIA/CCSA/NJSEC, and VGIC all addressed EVs and public fleets. Advanced Energy United asked for updated interconnection pathways for bidirectional EV charging based on operating mode. SEIA/CCSA/NJSEC recommended that public fleets participate through qualified aggregators or direct public-entity portfolios under the same performance and data rules as private resources. It recommended that initial pilots emphasize managed charging and incorporate

bidirectional export where equipment, warranties, operating schedules, and interconnection requirements allow. VGIC asked that school buses be included from the start, with technical assistance funding for school districts and incentives that favor bidirectional chargers.

**Staff Response:** Staff appreciates the commenters' feedback and notes that public fleets and managed EV charging may participate in the VPP Interim Program under the same technology-neutral eligibility rules as other resources. V2G compensation will be considered in the long-term framework, and interconnection pathways for bidirectional charging are outside the scope of this Order.

EEA-NJ, SEIA/CCSA/NJSEC, the Smart Thermostat Coalition, and VGIC all asked for an open, inclusive VPP Working Group. SEIA/CCSA/NJSEC asked that the Board lead the group, with broad membership including EDCs, aggregators, solar and torage companies, device providers, consumer and LMI advocates, public entities, cybersecurity experts, and PJM. It further suggested that the VPP Working Group should be synchronized with the PSUP and Grid Flexibility Services workgroups and meet monthly during design/launch, with quarterly meetings held afterwards, with agendas, materials, minutes, action items, and deadlines made public. EEA-NJ asked for initial monthly meetings with a potential reduction in frequency, and the Smart Thermostat Coalition and VGIC asked to include device makers, aggregators, and EV stakeholders.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the Order establishes the PowerUp NJ Working Group to facilitate collaboration among the Board, the EDCs, Rate Counsel, and relevant stakeholders, with subgroups organized to address specific workstreams. Staff will consider these suggestions on membership, meeting frequency, and public materials as the Working Group is organized.

ChargEVC asked for clear double-counting rules, for example barring a customer on an EV TOU rate from also enrolling in a VPP managed charging program, while allowing the same customer to join a thermostat program. It also asked that fleet programs reflect real duty cycles to encourage buy-in, rather than assuming vehicles are plugged in at fixed times.

**Staff Response:** Staff thanks the commenter for their feedback and notes that Attachment A requires each EDC to describe how it will attribute performance where more than one program serves the same

customer or device, and requires each baseline methodology to account for load changes caused by TOU rates or other programs. Each EDC proposes its eligible DER types and enrollment rules in its filing.

**liii. Advocacy Groups**

Commenter(s) Referenced in This Summary: CJNJ, Evergreen Action and EDF, NEEP, NJECN, NJEJA, Sierra Club, and Vote Solar

CJNJ, Evergreen Action and EDF, NJEJA, and Vote Solar all addressed GSESP Phase 2. Evergreen Action and EDF asked that VPP enrollment, for at least five years, be a condition of Phase 2 hardware incentives, with overlapping performance pay routed through Pathway 2 or 3, noting that the 350 MW Phase 2 target is 59.4% of the 589 MW Interim goal. CJNJ asked that the utility tranche of Phase 2 join the VPP from the start. NJEJA asked that storage with a Phase 2 performance incentive forgo PJM capacity pay or take a one-to-one reduction. Vote Solar recommended that GSESP-VPP coordination include device-level measurement and telemetry, a clear pathway for FOM storage eligibility and participation, and complementary incentives and compensation supporting LMI and OBC participation through subscriber-based community storage and community solar-plus-storage. It proposed that GSESP focus on upfront and hardware incentives for BTM and FOM storage and provide performance compensation for FOM resources not addressed by the proposed VPP framework, while the long-term VPP would incorporate FOM aggregation and locational grid-service compensation.

**Staff Response:** The Order integrates both VPP and GSESP Straws to create a coordinated program. This Order is the first step in creating a robust open market to compensate devices for their service to the grid.

Evergreen Action and EDF, NEEP, and NJECN all asked that EE-funded devices flow into the VPP. Evergreen Action and EDF recommended splitting connected-device incentives into a base EE rebate and a VPP enrollment adder tied to three years of participation. NEEP asked that EE programs market DR-capable devices and offer products already enrolled in DR, and suggested that utilities could conduct outreach to customers with existing connected devices to offer enrollment in VPP programs. NJECN asked the Board to move Triennium-, solar-, and EV-funded assets into the VPP quickly, especially for LMI customers, as those programs lose federal support.

**Staff Response:** The Order notes how EE incentivized devices can quickly ramp up a VPP and the Straw contemplates automatic enrollment for future EE and EV proceedings based on market factors.

Evergreen Action and EDF distinguished NEM compensation from VPP compensation, as did Vote Solar. Evergreen Action and EDF asked that an NEM credit not bar Pathway 1 or 2 pay, that Pathway 3 pay apply to separately measured dispatch, and that the Board consider a VPP export adder. Vote Solar stated that NEM pays for non-dispatchable exports, while the VPP pays for dispatch, so exports outside of dispatch events should stay under NEM. Sierra Club separately recommended removing residential solar sizing limits, making community solar eligible for VPP participation and prioritized for storage co-location, and ensuring that capacity or wholesale revenue earned through storage-enabled VPP participation remains additive to existing bill-credit discounts for LMI and other subscribers.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that, for now, customers with solar-only systems on a NEM tariff cannot include their solar systems in the VPP Interim Program, to avoid paying twice for the same value. Customers with solar plus storage, and other BTM residential and small commercial batteries, can participate through Block 1, where battery performance is measured at the device level, separate from NEM exports. Solar system size limits and community solar eligibility are outside the scope of this Order. Staff notes that this Order is the first step in developing a robust open market to compensate resources for their service to the grid.

Evergreen Action and EDF and NEEP both supported technology-neutral TOU rates. Evergreen Action and EDF asked for hold-harmless protection for customers who follow VPP dispatch that conflicts with TOU prices, and for baselines that account for TOU-induced shifting. NEEP supported potentially using TOU rates and peak time rebates together to encourage load shift.

**Staff Response:** As noted in the VPP Straw Order, TOU can play an important role in shifting load but are not the same as a VPP. Staff notes that many of the decisions regarding the long-term tariff will be determined in future Grid Mod proceedings via the Grid Flexibility Services workgroup (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*).

Evergreen Action and EDF and Sierra Club both supported bringing EVs and public fleets into the VPP. Evergreen Action and EDF asked that public resources use the same competitive pathways as other resources, with V2G prioritized at facilities serving overburdened communities. Sierra Club asked the Board to promptly resolve the proceedings evaluating EDC-filed medium- and heavy-duty EV ecosystem programs and take further action on temporary light-duty EV programs so those resources can be fully incorporated into the long-term VPP. It noted that New Jersey's EVs hold approximately 10 GW of distributed battery-storage capacity and that EV adoption continues to increase.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that EVs and public-sector resources may participate in the VPP Interim Program under the same technology-neutral eligibility and competitive contracting rules as other resources. V2G compensation will be considered in the long-term framework, and other EV matters are addressed in the Board's EV proceedings.

Evergreen Action and EDF, NJEJA, and Vote Solar all asked for a more inclusive VPP Working Group. Evergreen Action and EDF asked for seats for Rate Counsel, environmental justice groups, independent aggregators, NJDEP, and NJEDA, co-chaired by Staff and an independent consultant, with monthly then quarterly meetings. NJEJA asked for a Community Advisory Board in each EDC territory with veto authority. Vote Solar asked that the group form in early Q4 2026 through an open call, with LMI and overburdened community participation as a priority. Vote Solar also advocated for the inclusion of environmental justice groups, and called for transparency in selection of Working Group participants.

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Order establishes the PowerUp NJ Working Group to facilitate collaboration among the Board, the EDCs, Rate Counsel, and relevant stakeholders. Staff will consider these suggestions, including participation by environmental justice and community organizations, as the Working Group is organized.

### iv. Program Implementers and Administrators

Commenter(s) Referenced in This Summary: Energy Solutions, Michaels Energy, and Power TakeOff

Energy Solutions, Michaels Energy, and Power TakeOff all asked for close links between EE programs and the VPP. Energy Solutions asked that the

Interim Program consider a framework which enrolls DERs into load flex programs at the time they are installed through state incentive programs. Michaels Energy asked for an enrollment adder for C&I measures the Triennium already funds, DR-ready equipment specifications, combined Triennium and VPP funding, two-way referrals between EE audits and DR screening, and rules for attributing shared savings. Power TakeOff asked that the VPP pay for the congestion relief value of locationally targeted EE, while the Triennium continues to pay for energy savings.

**Staff Response:** Staff thanks commenters for the comments and notes that the EDC-run Interim Program is designed as a bridge from the existing small demand response programs to a long-term open market compensation-based program. This Interim program will expand the demand response programs, building the market and lowering peak demand while the Board stands up the long-term tariff. The Order calls for EDCs to provide a transition plan for customers currently in a demand response program, as well as how to transition customers to the long-term tariff. The Order and Straw reference the Triennium budgets as part of the basis for the recommended budget for these programs.

Power TakeOff supported the general description of the VPP Working Group, expressed interest in participating, and asked that the Working Group advise on program changes needed as PJM market rules change.

**Staff Response:** Staff thanks the commenter for this feedback and notes that the PowerUp NJ Working Group is intended to facilitate collaboration among the Board, the EDCs, Rate Counsel, and stakeholders, which may include discussion of program changes needed as PJM market rules evolve. The Order directs Staff to convene the Working Group upon approval of the EDC filings. Interested parties, including Power TakeOff, may request to participate at that time.

### Iv. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

Base Power asked that GSESP Phase 2 incentives target segments the market will not reach on its own, such as LMI customers and constrained circuits, and that participation across programs be allowed where each pays for a distinct service. It also asked that the VPP align with Data Center Fair Share Act obligations, and that the VPP Working Group and GridFlex Workgroup include a third-party supplier representative.

**Staff Response:** Staff recognizes that there are opportunities for collaboration between the proposed VPP programs under the PowerUp NJ program and the VPP called for in the Data Center Fair Share Act. Staff also notes that work has just begun on the Data Center Fair Share Act and that given the imperative work outlined in EO 1 and EO 2, the Interim Program should continue to progress while the Data Center Fair Share Act proceeding begins and notes that the Interim Program can provide learnings as the Data Center Fair Share Act programs are stood up. Further, the Grid Flexibility Services workgroup (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) has a third-party organization (NRG) at the table.

NRG asked that TOU rates and VPP pay be treated as complementary, with a few broadly applicable TOU offerings rather than one per technology, and that the VPP Working Group have a set timeline and meet more often at first.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that TOU rates can play an important role in shifting load but are not the same as a VPP, and that each EDC's baseline methodology must account for load changes caused by TOU rates or other programs. Staff will consider the suggested timeline and meeting frequency as the PowerUp NJ Working Group is organized.

**lvi. Government Agencies**

Commenter(s) Referenced in This Summary: SMRSA

SMRSA asked that Class I REC eligibility, NEM, PJM demand response, and VPP pay remain stackable for distinct services. It also asked the Board to consider an alternative tariff or pilot so renewable CHP at critical public infrastructure can export without losing NEM eligibility when generation exceeds annual use.

**Staff Response:** Staff thanks the commenter for their feedback and notes that, for any enrolled customer whose premise also has a resource in NEM or a PJM wholesale market program, each EDC must propose how the associated revenue streams will be treated and describe the safeguards that prevent double compensation for the same service. NEM eligibility and export tariffs remain under

consideration in a separate proceeding and are outside the scope of this Order.

### lvii. Financial Services

Commenter(s) Referenced in This Summary: Syntropic

Syntropic recommended that the Board recognize that upfront incentives are not prone to double compensation, and that ongoing performance incentives pose a greater risk of concern for “same service at the same time.” It suggested that the VPP framework implement a combined structure capturing both upfront capital contributions and dispatch performance, as it asserted that treating them identically for anti-double-counting purposes works against making the program financeable for LMI participants.

**Staff Response:** Staff thanks the commenters for the comment and notes that the Straw indicates that unlocking these multiple compensation streams while guarding against double payment is a long-term goal. Staff also notes that the Straw contemplates EE and EV hardware incentives remain within those proceedings and are not considering double payment, the straw also suggests looking at ways to encourage VPP participation with incentivized hardware.

### lviii. Individuals and Academic Institutions

Commenter(s) Referenced in This Summary: Bill Beren, Cammie Croft, Michael Winka, and UDelaware

Bill Beren asked the Board to coordinate the VPP with NJ Transit electrification, noting that NJ Transit could install solar along its right-of-way and has deferred its electric bus goals for lack of depot upgrade funding. He also asked the Board to restore EV rebates reduced when RGGI funds were diverted to rate relief, and to finish the medium- and heavy-duty EV make-ready tariffs.

**Staff Response:** Staff thanks the commenter for this recommendation and notes that public-sector resources, including NJ Transit fleets, may participate in the VPP Interim Program under the same technology-neutral eligibility rules as other resources. Funding for EV rebates and the medium- and heavy-duty EV make-ready tariffs are addressed in the Board’s EV proceedings and are outside the scope of this Order.

Cammie Croft requested that the interim program formally recognize community-benefit VPP capacity as a mechanism counting toward demand-reduction obligations under the Data Center Fair Share Act. She also asked that compensation exclusivity apply on a service-by-service basis.

**Staff Response:** Staff thanks the commenter for their recommendation and recognizes that there are opportunities for collaboration between the proposed VPP programs and the VPP called for in the Data Center Fair Share Act. Staff also notes that work has just begun on the Data Center Fair Share Act and that given the imperative work outlined in EO1 and EO 2 the Interim Program should continue to progress while the Data Center Fair Share Act proceeding beings and notes that the Interim Program can providing learnings as the Data Center Fair Share Act programs are stood up.

Michael Winka asked the Board to coordinate the long-term VPP with its utility business model study and the Higher Education Decarbonization Pilot, and to use governmental buildings like schools, municipalities, and colleges for sandbox pilots. He stated that the VPP value stack should cover energy grid services only, with emissions and other non-energy benefits paid through other relevant programs. Michael Winka also asked for diversified view points within the VPP Working Group, ensuring that members reflect expertise in DER OEM, DERA, and utility perspectives, while also including members with broader energy policy views. UDelaware asked the Board to state the interconnection pathways for EVs, including DC charging certified to UL 1741, AC charging that meets SAE J3072 or UL 1741-SC with UL 2594, or a matched EV-charger pair certified to UL 9741. UDelaware noted that a matched EV-charger pair can only be certified under UL 9741 and works for single-family homes with owned parking, but does not provide interoperability, so it is not appropriate for workplace, shared apartment, or public V2G charging. It also noted that SAE J3072 requires an open-standard protocol between the EV and the charger, currently either LIN-CP (defined in SAE J3068) or IEEE 2030.5.

**Staff Response:** The Straw and the Order note that the VPP Interim program is designed to bridge the gap until there is a tariff that DERs can participate in alongside additional wholesale compensation, its focus is on building a program that provides stackable compensation for a variety of grid services. In addition, adopting EV-specific interconnection standards is not within the scope of the Order and V2G compensation will be considered in the long-term framework.

# 8. Cost Recovery & EDC Ownership

***Straw Proposal section(s):*** *§ 3.8, Section 5*

**Summary of Comments:** The utilities asked for timely, predictable cost recovery, building on the Triennium 2 mechanisms, with rate-base treatment and a return for long-lived enabling investments such as DERMS and recovery that is neutral between wires and non-wires solutions. Rate Counsel, advocates, and most aggregators asked that program administration and incentives be expensed, with no return on payments passed through to customers or aggregators, and that capital treatment be limited to genuinely long-lived systems. Several asked for performance-based or shared-savings incentives tied to deferred capital or net ratepayer savings rather than to ownership. On EDC ownership, the utilities supported a bounded exception for needs such as constrained circuits, LMI access, and FOM storage. Rate Counsel and most aggregators, developers, and trade associations asked that competitive procurement come first, with EDC ownership only as a last resort after a failed solicitation and with neutrality safeguards, while CJNJ asked for broad utility ownership through a Networked Power Program.

### lix. Utilities and Utilities Association

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, and RECO

ACE, JCP&L, NJUA, PSE&G, and RECO all asked for timely, predictable cost recovery. ACE asked for a rider or tracker using the Triennium 2.0 mechanism at the same authorized ROE, with deferred accounting as a backstop, rate-base treatment and a return for DERMS, metering, telemetry, integration, cybersecurity, and data platforms, and recovery that is neutral between wires and non-wires solutions. NJUA asked that the Triennium 2 framework apply through the Interim Program and that the Board clarify recovery of enabling investments such as DERMS, AMI, and cybersecurity. RECO asked for a regulatory asset with amortization, noting that EDC recruitment, dispatch, and verification work are core program functions, not pass-through costs. JCP&L asked for a rider or other mechanism that also covers the cost of maintaining existing resources, and for clear transition rules for budgets, participants, regulatory assets, and recovery when the Interim Program starts. PSE&G stated that the EE recovery structure can serve the Interim Program, but asked that long-term recovery, including enabling investments, be discussed in the working group.

**Staff Response:** The Order does not allow any earnings opportunity for the EDCs with the Interim program and requires Staff to begin a

proceeding to determine alternative recovery mechanisms that are designed to address the goals of the program – including performance and shared savings mechanisms. The Order provides guidance on minimum requirements and provides EDCs with flexibility to propose alternatives with a description of why a deviation is necessary, recognizing that nascent markets may require flexibility in design.

ACE, PSE&G, and RECO all supported EDC ownership as a bounded exception. ACE supported it for constrained circuits, hosting-capacity limits, local reliability, LMI participation, FOM uses, and deferral, with five safeguards: an identified need, cost-effectiveness against alternatives, Board approval, cost transparency, and competitive procurement where practical. RECO supported EDC ownership of FOM storage, citing O&R's Pomona Battery, where net wholesale revenue is credited to customers, but not of EV chargers or BTM assets. PSE&G supported ownership where location-specific performance is needed and the market cannot match it, and asked that competitively procured storage move to EDC operation.

**Staff Response:** The Proactive System Upgrade Plan (see BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*) will be a parallel proceeding which will help identify constrained circuits, one of the use cases the Straw contemplates for EDC ownership.

### Ix. Division of Rate Counsel

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel stated that Section 5 is the least developed part of the Straw Proposal and asked the Board to set cost-recovery rules before any EDC filing. It recommended treating program administration and incentive costs as expenses, with no automatic rider, regulatory asset, or presumption of recovery, and carrying costs on any deferral limited to the EDC's cost of debt. It recommended that all revenues, penalties, and unspent funds flow back to customers, and opposed any utility incentive based on enrollment or spending or that pays twice for the same outcome.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order treats VPP Interim Program costs including administration and customer incentives, as Operating Expense recovered through the applicable EDC rider component approved under N.J.S.A. 48:3-98.1, with no return and subject to a prudence

standard. Costs are recovered in the year they are paid, subject to annual reconciliation of actual expenditures and rider revenues, and any carrying charges must reflect actual under- or over-recovered balances. The Order does not establish a performance incentive or shared-savings mechanism for the EDCs at this time.

Rate Counsel stated that VPP costs should be assigned primarily to data centers and other large loads driving the capacity need, through a large-load capacity-mitigation charge or special contracts, citing practices in Maryland, Ohio, and Virginia. It also recommended recovering administrative and participant-specific costs, such as licensing, data interfaces, and settlement, through fees on aggregators and participants rather than all ratepayers.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order recovers prudently incurred VPP Interim Program costs as Operating Expense through the applicable EDC rider component approved under N.J.S.A. 48:3-98.1, because reducing the zonal capacity obligation is a direct and measurable savings to all ratepayers in the zone. The Order does not establish a separate large-load charge or aggregator and participant fees for the VPP Interim Program. The Order also calls for an additional proceeding to help determine revenue recovery mechanisms more closely tied to the program's goals. Assignment of costs to data centers is beyond the scope of this particular proceeding and should instead be addressed as part of the Board's concurrent proceeding regarding the implementation of the Data Center Fair Share Act, N.J.S.A. 48:7-6.2 (see BPU Docket No. EO26080463 *In the Matter of Implementation of the Data Center Fair Share Act*).

Rate Counsel recommended hard budget caps by EDC, subprogram, and cost category; annual true-ups; disallowance of unsupported costs; and automatic suspension or termination when RIM results, costs, or benefits miss set thresholds. It noted that the Straw Proposal penalizes aggregators for poor performance but not programs for high costs. It asked for bill impacts by customer class and participation status and listed ten cost-recovery items each MFR filing should include.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order provides for annual reconciliation of actual expenditures and rider revenues, and that the Board retains the authority to review and disallow costs that are imprudent, unsupported, or duplicative. The budgets serve as guidance, and an EDC proposing

a budget that deviates by more than fifteen (15) percent must justify the difference. Following the Midterm Review, the Board will determine whether each program should be continued, modified, expanded, or phased out. Attachment A also requires rate and bill impacts by customer class.

Rate Counsel continued to oppose EDC ownership of storage, citing the Electric Discount and Energy Competition Act, near risk-free utility returns, and EDC control of interconnection and grid data. It opposed any EDC-owned storage target and recommended finding EDCs ineligible for storage programs. In response to Stakeholder Comment No. 21, however, the commenter stated that if the Board evaluates all proposals on total cost to customers, a separate exclusion rule may not be needed.

**Staff Response:** Staff thanks the commenter for their feedback.

Staff recognizes that there are specific use cases where utility owned and operated infrastructure, including storage, may be the quickest, most cost-effective method. The Board is currently looking at how to better define those use cases in future proceedings. Staff notes that the VPP Interim Program does not include EDC ownership of DERs, and the evidence needed to identify constrained circuits will be considered in those future proceedings.

**lxi. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: Calibrant, DCO, Electrify America, EnergyHub, ev.energy, Honeywell, Logical Buildings, Lunar, Nexamp, Piclo, Renew Home, Solar Landscape, Soltage, Uplight, Virtual Peaker, Voltus, and WeaveGrid

Calibrant, DCO, Electrify America, ev.energy, Lunar, and Voltus all asked that competitive procurement come before any EDC ownership. Voltus, Electrify America, and ev.energy asked that EDC ownership be available only where a competitive solicitation fails to meet a documented need. Lunar proposed an order of preference: customer- or third-party-owned storage with EDC dispatch rights, then a competitive RFP, and EDC ownership only after a demonstrated market failure on the circuit. Nexamp asked that EDC ownership remain a strictly bounded exception, limited to a demonstrated, site-specific distribution need that a competitive portfolio of third-party resources or a contractual dispatch arrangement cannot meet. It asked that non-wires alternative procurements be the main pathway for localized needs, citing New York's framework, which allows utility

ownership only when the market fails to respond to a demonstrated need, and its own Watertown project with National Grid. DCO asked that EDCs also consider customer-owned CHP microgrids through technology-neutral RFPs. Calibrant opposed EDC ownership even on constrained circuits, noting that EDCs would decide which circuits are constrained without an independent check. Edge Zero took no position on ownership but noted that all three deployment models in the Straw Proposal depend on first identifying which circuits are truly constrained, and asked that any EDC constrained-circuit petition state whether its finding is based on measured or estimated data.

**Staff Response:** Staff thanks the commenters for their feedback. Staff recognizes that there are specific use cases where utility owned and operated infrastructure, including storage, may be the quickest, most cost-effective method. The Board is currently looking at how to better define those use cases in future proceedings. Staff notes that the VPP Interim Program does not include EDC ownership of DERs, and the evidence needed to identify constrained circuits will be considered in those future proceedings.

Honeywell, Piclo, Solar Landscape, Soltage, and Uplight all supported other ownership or contracting models in defined cases. Soltage preferred third-party ownership and operation with EDC dispatch signals, citing Xcel Colorado, with a possible build-transfer model. Solar Landscape supported developer-owned resources under availability or capacity contracts and projects built by developers and later acquired by the EDC. Uplight supported EDC ownership for constrained locations and for low-income customers who face barriers to owning DERs, without requiring other models to fail first. Honeywell asked that any EDC proposal document the need, alternatives, costs, customer impacts, and neutrality safeguards. Piclo stated that an EDC affiliate could participate in VPP aggregation, provided it does so on equal terms with three safeguards: (i) structural separation of the affiliate's VPP operations from the EDC's grid operations, (ii) no access to non-public grid data, and (iii) full compliance with the same licensing, qualification, and reporting requirements imposed on third-party aggregators.

**Staff Response:** Staff thanks the commenters for their feedback on DER ownership models. The PowerUp NJ VPP Interim Program does not include EDC ownership of DERs. Staff recognizes that there may be specific use cases where other ownership or contracting models are appropriate, and these will be considered in future proceedings.

EnergyHub and ev.energy addressed how VPP costs should be classified and recovered. EnergyHub and ev.energy both asked that participant incentives and program administration be expensed. EnergyHub recommended recovering them through a VPP rider with annual reconciliation, while capitalizing DERMS platform costs as a software asset and amortizing one-time launch costs. ev.energy asked the Board to clarify early how Pathway 1–3 aggregator pay will be treated for recovery, since this affects contract bankability. WeaveGrid separately recommended preserving EDC flexibility to make reasonable enabling investments during program development, including investments in Edge DERMS, data integration, telemetry, customer acquisition, marketing, M&V, and program administration.

**Staff Response:** The Order does not allow any revenue opportunity for the EDCs with the Interim program and requires Staff to begin a proceeding to determine alternative recovery mechanisms that are designed to address the goals of the program – including performance and shared savings mechanism. Staff also notes that the PowerUp NJ program Straw Order and Order both indicate that the Interim program should not require DERMs to be built.

DCO and Virtual Peaker both asked that recovery and utility incentives reflect deferred capital. DCO recommended three complementary mechanisms for qualified new projects: (1) an EDC-administered or State-funded upfront participant incentive, in dollars per kW of estimated qualified peak-load reduction from a new sustainable microgrid, with true-ups or clawbacks for underperformance; (2) a sustainable-microgrid tariff with an annual $/kW payment for calculated or verified peak-load reduction plus performance pay for dispatched services; and (3) a capped, independently verified shared-savings or performance-based incentive that rewards an EDC when competitively procured VPP resources defer an approved capital project, reduce peak-capacity costs, or deliver verified locational benefits at lower total ratepayer cost, tied to net benefits rather than ownership. DCO also asked for a contract or tariff commitment of at least seven years for qualified new projects. Virtual Peaker asked that program costs be recoverable on a basis commensurate with the value and duration of the deferred investment, including amortization over the deferral period, with the reliability value credited separately.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the Order does not establish a performance incentive or shared-savings mechanism at this time. The initial program period is

intended to establish reliable baselines for program performance, avoided costs, and ratepayer savings. Following the VPP Interim Program Midterm Review, Staff will evaluate a mechanism under which EDC earnings would depend on independently verified savings or performance above the minimum requirements established by the Board.

Honeywell, Logical Buildings, and Renew Home all addressed budget structure. Honeywell and Logical Buildings asked that filings separately identify customer incentives, enabling technology and integration, aggregator or contractor pay, EM&V, cybersecurity, and administration, with Honeywell asking for each category's purpose, useful life, and beneficiaries. Renew Home asked that EDCs be allowed to shift funds across pathways and measures within the approved budget, or up to a set percentage, without a separate filing.

**Staff Response:** Staff appreciates the commenters' feedback and notes that Attachment A requires each EDC to break out projected costs by category, including customer incentives, performance-based payments to VPP providers, administration, outside services, inspection and quality control, and EM&V, with any proposed capital cost identified separately. The budgets in the Order serve as guidance, and the treatment of budget flexibility within an approved program will be addressed in the Board's review of each EDC's petition.

### lxii. Trade Associations

Commenter(s) Referenced in This Summary: ChargEVC, EEA-NJ, NJCCC, and SEIA/CCSA/NJSEC

EEA-NJ, NJCCC, and SEIA/CCSA/NJSEC all opposed broad utility ownership of DERs. SEIA/CCSA/NJSEC requested that EDC ownership be a narrow, last-resort exception after a technology-neutral solicitation. It clarified that EDC ownership should be limited in scope and time, separately accounted for, and independently evaluated, and, if allowed at all, run as an independent unit not recovered through rates with equal data access for competitors. NJCCC opposed any utility ownership of battery storage, stating that published Proactive System Upgrade Plan (PSUP) constraint data would let developers serve constrained areas at lower cost. EEA-NJ asked that EDC ownership be limited to what reliability requires, that EDC-owned capacity be capped like the 40% aggregator cap, and that EDC-owned assets be located on PSUP-identified constrained circuits.

**Staff Response:** Staff thanks the commenters for their feedback on EDC ownership of DER assets, especially energy storage. The PowerUp NJ Order's VPP Interim program does not allow for EDCs to own DER assets.

ChargEVC and SEIA/CCSA/NJSEC both addressed cost-recovery treatment, although their recommendations focused on different issues. ChargEVC asked the Board to align utility financial incentives with the VPP market design so that DER solutions can compete equally with traditional infrastructure based on cost-effectiveness. SEIA/CCSA/NJSEC recommended generally treating program administration, outreach, measurement, settlement, and performance payments as operating expenses. It stated that long-lived shared IT or DERMS investments may be capitalized only if they satisfy normal accounting standards, are prudently incurred, and are not duplicative. It also recommended allowing hardware incentives to be amortized over the related customer commitment while prohibiting excessive EDC returns on pass-through incentives or competitive service payments.

**Staff Response:** Staff appreciates the commenters' feedback. The PowerUp NJ Order does not allow any revenue opportunity for the EDCs with the Interim program and requires Staff to begin a proceeding to determine alternative recovery mechanisms that are designed to address the goals of the program – including performance and shared savings mechanism.

### lxiii. Advocacy Groups

Commenter(s) Referenced in This Summary: Ceres, CJNJ, Evergreen Action and EDF, NEEP, NJECN, NJEJA, and Sierra Club

Ceres, Evergreen Action and EDF, NJECN, and Sierra Club all addressed when EDC ownership should be allowed. Evergreen Action and EDF asked that EDC ownership follow only a documented, failed competitive solicitation, with customer-owned assets and EDC dispatch rights as the default and notice to overburdened communities where EDC assets would be sited. Sierra Club suggested a competitive solicitation open to public and private parties, including a potential public VPP and community solar, wherein EDCs need to show that these third parties were given opportunities to serve the identified distribution need. Sierra Club also stated that the Board should require a cost comparison between rate-based EDC ownership and competitively financed alternatives, along with EDC returns being tied mainly to performance and any exceptions bounded in

place and time. It also asked that EDCs not favor themselves or affiliates and share data with all aggregators on equal terms. NJECN supported EDC-owned storage at grid shortage locations, especially in LMI neighborhoods, with competitive procurement between the EDC and private investors. Ceres asked that the program allow both third-party and utility-owned resources.

**Staff Response:** Staff thanks the commenters for their feedback on EDC ownership of DER assets and notes that the Order does not allow for EDC ownership of DERs. The Straw supports strong open markets but recognizes that in order to develop them correctly a tariff must be designed to compensate for the services provides to the grid. While Board Staff develop requirements for such a tariff via the Grid Flexibility Services workstream (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*), the VPP Interim program will build off of the demand response foundation built from the Triennium proceedings.

Evergreen Action and EDF, NEEP, and NJEJA all addressed cost recovery and utility incentives. Evergreen Action and EDF asked that administration, incentives, and aggregator payments be expensed, with capital treatment limited to EDC-owned long-lived infrastructure, such as DERMS, and no return on incentives, noting that the classification can bias EDCs toward ownership. NEEP recommended full symmetrical revenue decoupling, which would enable utilities to recover investment and operating costs regardless of sales volume. NJEJA asked that cost recovery depend on meeting equity metrics, with recovery withheld for shortfalls, quarterly equity reports, and civil penalties.

**Staff Response:** The Order does not allow any earnings opportunity for the EDCs with the Interim program and requires Staff to begin a proceeding to determine alternative recovery mechanisms that are designed to address the goals of the program – including performance and shared savings mechanism.

CJNJ asked the Board to adopt a utility-led Networked Power Program or, short of that, a broad utility ownership exception for FOM and BTM DERs, citing needs such as PJM's projected shortfall, constrained circuits, and hosting capacity. It stated that EDECA permits utility-owned storage that serves a distribution function, and recommended financing BTM assets through an Inclusive Utility Investment tariff tied to the property and recovering FOM assets through rate base. CJNJ preferred full utility

ownership over utility-administered third-party ownership, stating that this structure offers the fastest pathway to close the PJM capacity gap.

**Staff Response:** Staff thanks the commenter for their feedback. The Order does not allow for EDCs to own DER assets at this junction.

### lxiv. Program Implementers and Administrators

Commenter(s) Referenced in This Summary: Ampion

Ampion asked that settlement be recovered as a competitively procured operating expense rather than rate-based by each EDC, noting that four EDCs building their own settlement systems would mean four builds and four returns for one function. Ampion argued that creating a VPP Settlement Administrator or "VSA" role within the PowerUp NJ program would present the least-cost pathway for ratepayers, and emphasized the need for a competitive VSA market.

**Staff Response:** The Order does not allow any revenue opportunity for the EDCs with the Interim program and requires Staff to begin a proceeding to determine alternative recovery mechanisms that are designed to address the goals of the program – including performance and shared savings mechanism. The Order provides guidance on minimum requirements and provides EDCs with flexibility to contract for the services called for.

### lxv. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

NRG opposed EDC ownership of customer-sited or generation-adjacent DERs, including batteries, as a routine practice, citing EDECA's separation of generation and distribution. It recommended competitive solicitations for PSUP-identified constrained circuits.

**Staff Response:** Staff thanks the commenters for their feedback and recognizes that there are specific use cases where utility owned and operated infrastructure, including storage, may be the quickest, most cost-effective method. The Board is currently looking at how to better define those use cases in future proceedings.

Base Power stated that third-party suppliers could finance and deploy residential storage without upfront ratepayer-funded deployment incentives for capacity and transmission value if negative PLC and NSPLC accounting

and Peak Shaving Adjustments or successor load-forecast mechanisms are enabled. It recommended counting verified supplier-facilitated demand reductions toward each EDC's peak-reduction target and any future EDC shareholder performance incentives. Base Power also recommended allowing third-party suppliers to receive compensation for distribution services under the long-term VPP framework without registering as DER aggregators.

**Staff Response:** Staff thanks the commenter for the comment. The Order requires each EDC to submit a PSA plan to PJM by September 10 of each year, beginning in 2027. However, there is currently no method by which the zonal load reductions provided by BTM storage exports can be captured in a PSA plan. The Order instead directs each EDC to develop a plan to revise its PLC calculation and reporting methods to account for negative PLCs, and to file a summary of that plan with the Board by February 12, 2027. Staff acknowledges that this change may help enable business models that support storage deployment without the need for state-supplied incentives, such as third-party suppliers offering their retail customers rate reductions for operating BTM storage to reduce peak load. Staff also understands that these changes may not be sufficient on their own and that unlocking the full benefit of Base's approach may require modifications to PJM's Manuals. The Order does not establish an EDC performance incentive, and Staff will evaluate potential performance incentives after the VPP Interim Program Midterm review. Distribution value for third-party suppliers will be considered in the long-term open-access VPP tariff. Individuals and Academic Institutions

Commenter(s) Referenced in This Summary: Cammie Croft and Michael Winka

Cammie Croft supported targeted storage on constrained circuits in low- and moderate- income ("LMI") communities when procured through a competitive solicitation open to community-benefit entities.

**Staff Response:** Staff thanks the commenter for their feedback and notes that residential and small commercial BTM storage is addressed through Block 1 of the Garden State Energy Storage Program. Staff recognizes that targeted storage on constrained circuits may serve specific needs, and procurement approaches for these use cases will be considered in future proceedings.

Michael Winka, advocating for a DSO model in the long-term program, stated that under such a framework utilities should not own DER assets because a utility cannot act as a neutral system manager while owning competing assets. The commenter recommended raising pay in constrained areas to attract the needed services instead.

**Staff Response:** Staff thanks the commenter for their feedback on EDC ownership of DER assets. The VPP Interim program does not allow EDC ownership of DER assets at this junction. Further development of grid services assets will occur under the purview of the Grid Flexibility Services workstream (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid).*

# 9. Consumer Protection, Data & Equity

***Straw Proposal section(s):*** *§ 6.1–6.5*

**Summary of Comments:** Commenters generally supported the data-access timeframes, single DER registry, aggregator licensing, shared-responsibility cybersecurity model, and three-tier data structure, but differed on the details. The utilities asked for timeframes that vary by data type and for notice and corrective action, not penalties, when a deadline is missed, while Rate Counsel, SEIA/CCSA/NJSEC, and several aggregators proposed fixed deadlines with remedies. Most asked that VPP fields be added to the PSUP registry rather than a separate registry, and several asked for location, settlement, ownership, and overburdened community fields. Third-party suppliers, several utilities, and aggregators asked that licensing build on existing licenses and scale with size and risk. Most supported flexible ways to show cybersecurity compliance, such as ISO 27001 or attestations in place of SOC 2 Type II, with standards phased in over time. On LMI access, commenters agreed that upfront cost, renter and multifamily status, and access to credit are the main barriers. They proposed no-cost or enhanced incentives, dedicated budgets or targets, community-based outreach, multifamily pathways, and consumer protections for financing.

### lxvi. Utilities and Utilities Association

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJNG, NJUA, PSE&G, and RECO

ACE, PSE&G, and RECO all asked that data-response timeframes vary by data type and that a missed deadline lead to notice and corrective action rather than penalties. ACE proposed 2–5 business days for enrollment

verification, 2–3 business days for unenrollment, and 5–10 business days for event-performance data, with a notice giving the reason for a delay and a revised date. RECO proposed 30 days for final event results, and PSE&G noted that some delays are outside the EDC's control. On scorecards, ACE asked for statewide metrics aligned with the Proactive System Upgrade Plan and Grid Flexibility Services, and RECO asked for a uniform statewide method that reports MW enrolled and delivered, realized savings, and cost-effectiveness.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the PowerUp NJ Program Order's Attachment A requires each EDC to describe the process and timeframe by which it will make customer data available to a customer's authorized aggregator, subject to Board review. Each EDC must also propose quantitative performance indicators and report enrolled capacity, verified load reduction, cost to achieve, and benefit-cost results, and the Order specifies common benefit and cost line items so that results are comparable across the EDCs.

ACE, JCP&L, NJUA, PSE&G, and RECO all addressed the DER registry. ACE supported a single framework but preferred EDC-managed registries with Board-approved fields, with VPP fields such as telemetry, device availability, location, and settlement data added to PSUP Appendix B. PSE&G stated that the EDCs should jointly develop the registry under the PSUP. RECO opposed an EDC-owned registry, citing the administrative burden without clear benefits, and stated that the PSUP Straw Proposal is overly prescriptive. JCP&L asked the Board to define the registry's purpose, governance, data fields, and funding first, and to build on existing utility and FERC Order No. 2222 records. NJUA asked the Board to clarify which DER types the registry covers and whether non-participating customer-owned DERs are included. It also asked that registry inclusion not authorize marketing, that customers opt in to aggregator marketing, and that customer data be anonymized unless the customer agrees otherwise.

**Staff Response:** Staff thanks the commenters for their feedback on the DER Registry requirements listed in the Proactive System Upgrade Plan Straw, which can be accessed at BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*. The development of the DER Registry will, in part, be determined under the PowerUp NJ working group.

ACE, JCP&L, PSE&G, and RECO all addressed aggregator licensing. ACE and RECO asked the Board to build on existing frameworks rather than create a new license. ACE pointed to the Energy Agent and Private Aggregator rules, and RECO to existing PJM, state, and EDC requirements. ACE also asked that licensing add Zero Trust controls (NIST SP 800-207), software bills of materials for connected devices (NIST SP 800-218), vulnerability management, 24/7 security monitoring, and annual consent renewal. JCP&L supported a Board-administered framework covering technical, cybersecurity, financial, insurance, consent, and complaint-handling requirements, with protections that last for the full period of participation. PSE&G asked that requirements match market risk and supported an EDC-maintained aggregator list that protects competitively sensitive information.

**Staff Response:** Staff acknowledges the commenters' feedback on DER aggregator licensing and notes that the Order does not establish aggregator licensing for the VPP Interim Program. The Order anticipates stakeholder engagement on a Board-administered licensing framework and code of conduct through the PowerUp NJ Working Group over the next thirty (30) months, where the use of existing frameworks and the scope of requirements can be considered.

ACE, JCP&L, PSE&G, and RECO all supported the shared-responsibility model but asked that roles be clearly assigned. JCP&L asked that aggregators be responsible for device security, updates, and replacement, and for the customer data they hold, and stated that it should not be responsible for third-party practices. RECO asked the Board to state who collects and stores customer consent, to let utilities validate aggregator controls, and to extend requirements to subcontractors. It also asked for incident reporting by severity, limits on data retention, and access only to the minimum data needed. JCP&L also supported data minimization. ACE asked for disclosure of all data shared in each tier and annual consent renewal, and PSE&G asked that AMI data remain the authoritative record for billing and settlement.

**Staff Response:** Staff appreciates the commenters' support for the shared-responsibility model and feedback that additional clarity on roles is needed in places. The shared-responsibility cybersecurity model is among the market support structures to be developed through the PowerUp NJ Working Group over the next 30 months. For the VPP Interim Program, each EDC must describe in its filing the standards, controls, and incident-response procedures that apply to its dispatch and DER management systems and to any third-party aggregator that

interfaces with those systems, together with the customer consent and data-privacy protections for enrolled customer data.

ACE, PSE&G, and RECO all supported multiple ways to show compliance and a phased approach to standards. PSE&G asked that some standards be treated as guidance during the Interim Program and phased in as the market matures. RECO supported certifications, attestations, or vendor documentation, and asked that each EDC be able to set and enforce its own data exchange standards through contracts. ACE stated that it will not have IEEE 2030.5 and 1547.3 capability at Interim Program launch. It asked that Zero Trust controls, software bills of materials, vulnerability management, and logging be required during the Interim Program, with full DERMS segmentation and NISTIR 7628 alignment later.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the baseline cybersecurity standards described in the Order are part of the market support structures to be developed through the PowerUp NJ Working Group over the next 30 months. For the VPP Interim Program, each EDC must describe in its filing the standards, controls, and incident-response procedures that apply to its dispatch and DER management systems and to any third-party aggregator that interfaces with those systems.

ACE, PSE&G, and RECO all identified upfront cost and housing type as the main LMI barriers. ACE recommended load control switches that run over the utility AMI network rather than customer Wi-Fi, along with no-cost enrollment, turnkey installation, and targeted incentives for renters. PSE&G requested an EDC-managed pathway that provides incentives for VPP-ready DERs for LMI customers. RECO recommended passive managed charging through vehicle telematics and cited O&R's New York programs, where targeted outreach and enhanced incentives improved participation in disadvantaged communities.

**Staff Response:** Staff thanks the commenters for their feedback.Staff does not deem the acquisition of further infrastructure necessary (load control switches) to utilize AMI data prudent when such data may be accessed via Wi-Fi, especially as the intention of AMI buildout was to increase metering data access capabilities. Staff notes that passive managed charging is already being pursued via another Board initiative under BPU Docket No. QO26060351, *In the Matter of the Light-Duty Electric Vehicle Charging Ecosystem And Load Management*. Staff also notes that the EDCs have the ability to propose incentive structure as part of their filings.

NJNG asked the Board to recognize the resilience value of dispatchable resources at affordable housing, senior housing, shelters, healthcare facilities, and other community sites.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the benefit line items in Attachment A include a non-energy benefit adder and a low-income adder under the NJCT and Societal Cost Test, and that each EDC may provide additional benefit-cost analysis with supporting documentation. Further, Staff intends for the future EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics.

### lxvii. Division of Rate Counsel

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel recommended monthly enrollment and unenrollment data and event-performance data within 10 days. For EDCs with a pattern of missed timeframes, it suggested booking compensation as a regulatory asset with a limited return until cured. It asked that scorecards show program costs and net benefits, and it supported adding VPP fields to the single DER registry through the PSUP.

**Staff Response:** Staff appreciates the commenter's feedback and notes that the Order requires quarterly enrollment reporting, event-level reports on a cadence proposed by each EDC, and annual reporting of benefit-cost ratios under all six tests using actual costs and verified savings. The DER registry is among the market support structures to be addressed through the PowerUp NJ Working Group.

Rate Counsel found the licensing requirements appropriately scoped and recommended low application and renewal fees. It was concerned that cybersecurity costs could discourage aggregators, and recommended requiring IEEE 2030.5 and 1547.3-compliant equipment and adherence to SOC 2 principles without audits or Type II reports. It offered no other changes to the code of conduct, data-access tiers, or security standards.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that aggregator licensing, the code of conduct, and baseline cybersecurity standards are among the market support structures to be developed through the PowerUp NJ Working Group over the next 30 months, where fee levels and the cost of compliance can be considered.

Rate Counsel stated that LMI customers and renters face barriers to DER adoption and suggested landlord outreach and cost-effective hardware incentives so they can enroll in VPP programs. It stated that offering an enrollment pathway does not make a program equitable and asked for bill impacts by class and distributional analyses showing that customers least able to buy DERs are not funding benefits for others.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that each EDC must describe how its program will reduce barriers for LMI customers and customers in overburdened communities, and must report participation by these customers. Attachment A also requires rate and bill impacts by customer class, and the RIM test, as the primary cost-effectiveness test, measures the effect of the program on customers who do not participate.

### lxviii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)

Commenter(s) Referenced in This Summary: Edge Zero, Edgeli, EnergyHub, ev.energy, Honeywell, Koolbridge, Logical Buildings, Lunar, ModernElectric, Oracle, Piclo, Renew Home, RExChain, Solar Landscape, Steffes, SunStrong, Tri-State, Turtle & Hughes, and Uplight.

ModernElectric and Piclo proposed defined EDC response times for enrollment, unenrollment, and event-performance data; Edgeli sought standardized public distribution-system data; and Turtle & Hughes focused on coordinating enrollment with project delivery and allowing service providers to assist customers. Piclo proposed hard service-level agreements requiring enrollment verification within five (5) business days, unenrollment confirmation within two (2) business days, and event-performance meter data within forty-eight (48) hours, or twenty-four (24) hours where required for PJM settlement. Piclo also recommended automatic remedies: settlement would default to aggregator telemetry when EDC data is late, enrollment verification not completed by the deadline would be deemed approved, and repeated noncompliance would trigger Board review and public reporting. ModernElectric separately proposed five (5) business days for standard residential enrollment verification and unenrollment confirmation and ten (10) business days after validated meter data becomes available for event-performance data. Edgeli asked EDCs to publish grid data in common open formats, refreshed at least quarterly. Turtle & Hughes recommended coordinating VPP enrollment with interconnection and commissioning requirements so technically ready resources can enter without avoidable delay. It also

recommended permitting authorized service providers, subject to customer-consent and cybersecurity protections, to manage applications, documentation, commissioning records, performance data, and ongoing compliance for customers. ModernElectric recommended the establishment of a public VPP Cost Savings Scorecard which reports enrolled, available, and delivered capacity, avoided capacity and distribution costs, program costs by category, customer payments and retention, and aggregator performance.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the MFRs ("Attachment A") requires each EDC to describe its enrollment processes and the process and timeframe by which it will make customer data available to a customer's authorized aggregator, subject to Board review. Each EDC must also describe how it will incorporate VPP grid services into distribution planning and report enrolled devices and kW by ZIP code and, where identified, on constrained circuits. Further, Staff intends for the future EM&V subgroup of the PowerUp NJ Working Group to establish future goals, measurements and metrics such as those requested by the commenters.

Edge Zero, Edgeli, ev.energy, Honeywell, ModernElectric, Piclo, and RExChain all asked to expand or define the registry fields. Edge Zero and Edgeli asked for circuit and transformer identifiers, and ev.energy asked that fields stay aligned with the PSUP. Piclo and ModernElectric asked that the registry track enrollments and PJM participation to prevent double counting. RExChain asked that the registry integrate with PJM GATS data rather than duplicate it, and Honeywell asked for a common data model that names a source for each field.

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Order anticipates DER registries with a consistent structure across the EDCs, containing common data fields and definitions, to enable enrollment, prevent double counting across compensation streams, and support grid reliability. The specific fields will be addressed through the PowerUp NJ Working Group over the next 30 months.

ev.energy, Honeywell, Logical Buildings, and ModernElectric asked that licensing or compliance requirements scale with an aggregator's size or risk, while Piclo supported light-touch statewide licensing and qualification requirements. Logical Buildings asked that aggregators be able to bid while a license is pending, with a decision within sixty (60) days. Piclo

recommended one Board-issued license and technical qualification valid across all four EDC territories without duplicative EDC-level qualification. Separately, Piclo supported using the single statewide DER registry developed through the PSUP proceeding rather than creating a separate VPP registry. ModernElectric asked that the Code of Conduct make clear that aggregators are not electric suppliers, and ev.energy asked for a non-discrimination clause protecting aggregator access to EDC systems.

**Staff Response:** Staff acknowledges the comments and notes that the Order does not establish aggregator licensing for the VPP Interim Program. The Order anticipates stakeholder engagement on a Board-administered licensing framework and code of conduct through the PowerUp NJ Working Group over the next 30 months, where the scope of requirements, timing, and non-discrimination provisions can be considered. Staff appreciates Piclo's recommendation that the DER registry remain in the PSUP proceeding (See BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*)

EnergyHub, ev.energy, Honeywell, ModernElectric, and Piclo recommended flexible, risk-calibrated methods for demonstrating cybersecurity compliance. Piclo asked the Board to accept ISO/IEC 27001 certification or verified vendor attestations as alternatives to SOC 2 Type II, noting the cost of obtaining a SOC 2 report. ev.energy recommended recognizing existing certifications and providing a twelve- to eighteen-month phase-in for smaller aggregators, while ModernElectric favored attestations rather than a full utility audit. EnergyHub opposed adding mandatory standards before EDC platforms and interfaces are known and proposed three alternatives to SOC 2 Type II: recognition of equivalent independently audited frameworks, including ISO/IEC 27001, HITRUST CSF, and FedRAMP Moderate; reliance on an Edge DERMS provider's SOC 2 attestation for infrastructure-layer controls, supplemented by evidence covering aggregator-level controls; and, for qualifying early-stage aggregators, an independently reviewed NIST Cybersecurity Framework self-assessment accompanied by a roadmap to SOC 2 Type II or an equivalent certification within twenty-four months. Honeywell recommended a shared-responsibility cybersecurity framework that assigns control ownership, evidence obligations, incident duties, and escalation authority among EDCs, aggregators, OEMs, integration providers, and cloud providers. It further recommended risk-proportionate controls, responsibility matrices identifying accountable and supporting parties, confidential review of appropriately scoped security evidence, and

incident procedures governing reporting, operational isolation, evidence preservation, recovery, return to service, and requalification. Honeywell also recommended that no single certification qualify a provider for every function and that EDCs retain authority over access to their systems and operational interfaces.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the baseline cybersecurity standards described in the Order are part of the market support structures to be developed through the PowerUp NJ Working Group over the next 30 months, where acceptable methods to demonstrate compliance and any phase-in can be considered. For the VPP Interim Program, each EDC must describe the standards and controls that apply to any third-party aggregator interfacing with its systems.

Honeywell, Koolbridge, Logical Buildings, Lunar, and Steffes all asked for clear customer protections. Honeywell and Logical Buildings asked for standard plain-language disclosures, and Logical Buildings asked for one statewide authorization form. Koolbridge and Steffes asked for customer override rights, and Lunar asked that customer trust be an evaluation criterion.

**Staff Response:** Staff thanks the commenters for their feedback and notes that the Order preserves customer opt-out rights for any individual event. The code of conduct anticipated in the Order is expected to address required disclosures, prohibited sales and enrollment practices, limits on opt-out penalties, and customer data usage restrictions. Each EDC's marketing plan must also explain how program services, incentives, and bill savings will be conveyed to customers.

Lunar, ModernElectric, Renew Home, Uplight, and ev.energy all asked for no- or low-upfront-cost options for LMI customers. Lunar asked that at least 15% of each EDC's program budget go to LMI programs and that meter socket adapters qualify to avoid panel upgrades. ModernElectric suggested an LMI adder or target and minimum bill credits during pilots. Renew Home and ev.energy recommended bring-your-own-device or no-upfront-cost models, and Uplight supported EDC-run or EDC-owned deployment as a targeted option for LMI customers in order to expand participation to customers who might otherwise be excluded from the program.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the Order does not set a minimum LMI budget share for the VPP Interim Program. Each EDC must describe how its program will reduce barriers to participation for LMI customers and customers in overburdened communities and must report participation by these customers. Because the Interim Program builds on devices customers already own, hardware incentives, including enabling equipment, continue to be offered through other Board-approved programs.

Koolbridge, Logical Buildings, Oracle, Piclo, RExChain, Solar Landscape, and Tri-State all proposed other paths to reach LMI customers. Logical Buildings asked for multifamily pathways and reporting by housing type and LMI status. Oracle stated that behavioral DR reaches customers without devices, and Solar Landscape requested that equity incentives or adders be made available for qualifying community-sited and FOM storage either located in or serving LMI or overburdened communities where projects have measurable benefits. Koolbridge asked that its demonstration recruit LMI homes, Tri-State stated that programs that allow users to take out low-cost loans are helpful and popular, RExChain supports the Board's equity objectives and encouraged the Board to recognize aggregators with established relationships in overburdened and institutional communities as a channel for VPP outreach, such as its experience serving nonprofit, school, and other mission driven solar hosts, and Piclo stated that open markets inherently lower entry costs for community-based and LMI-focused aggregators. SunStrong recommended opt-out enrollment for residential solar and storage customers where the aggregator already holds contractual authorization, citing its experience in Puerto Rico.

**Staff Response:** Staff appreciates the commenters' feedback and notes that each EDC must describe in its filing how its program will reduce barriers for LMI customers and customers in overburdened communities, and must report participation by these customers. The VPP Interim Program is open to any DER type that can deliver dispatchable demand reduction, and equity and LMI access are also among the market support structures to be addressed through the PowerUp NJ Working Group. Staff further notes that the PowerUp NJ Straw proposal indicated that the VPP Interim program is just the first step in building out a robust market for storage and grid services. Such considerations as suggested by the commenter will be further deliberated in the PowerUp NJ Working Group.

**lxix. Trade Associations**

Commenter(s) Referenced in This Summary: ChargEVC, EEA-NJ, SEIA/CCSA/NJSEC, and VGIC

EEA-NJ and SEIA/CCSA/NJSEC identified upfront cost as the main barrier to LMI participation in the program. EEA-NJ requested robust upfront rebates, a streamlined renter application, better alignment of incentives between homeowners and residents, and simple participation rules for LMI customers and renters. SEIA/CCSA/NJSEC asked for enhanced or fully funded enablement, no-credit-check options, renter and multifamily participation, trusted community outreach, multilingual materials, simple consent, minimum-benefit protections, and portability when customers move. It also asked that aggregators be paid for enrolling hard-to-reach customers through upfront payments that do not affect the performance-payment cost-benefit analysis. ChargEVC recommended that the Board support standard applications, customer education, integrated program design, flexible financing, third-party participation, and incentive structures that are able to be underwritten by customers or third-party investors.

**Staff Response:** Staff thanks the commenters for the comment notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services. The long term VPP tariff, which is already being worked on through the Grid Flexibility Services workstream (See BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) will provide parameters for participation.

SEIA/CCSA/NJSEC proposed fixed data deadlines: two (2) business days for enrollment verification, one (1) for unenrollment, two (2) for preliminary event data, and thirty (30) for settlement-quality data. They specified that missed deadlines ought to trigger automated notices with explanations, corrective action, and a completion date. Repeated failures should lead to public reporting, corrective-action plans, reimbursement of lost payments, and Board enforcement. They requested that planning-related VPP fields be added to Proactive System Upgrade Plan Appendix B, while customer and settlement data stay in the VPP proceeding.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that Attachment A requires each EDC to describe the process and timeframe by which it will make customer data available to a customer's authorized aggregator, subject to Board review. The DER registry, including the relationship between VPP fields and the PSUP,

is among the market support structures to be addressed through the PowerUp NJ Working Group.

SEIA/CCSA/NJSEC stated that DERA licensing should protect customers and avoid inhibiting new market entrants, and that a separate BTM storage aggregator license would be overly inhibitive. Rather, DERA license requirements and fees should scale with the applicant's risk and portfolio size. SEIA/CCSA/NJSEC also stated that the Board should be responsible for maintaining the official DER aggregator list, rather than the EDCs. They supported shared responsibility with clear roles and obtaining all relevant customer consent releases and agreements at the time of enrollment rather than consent by tier. It asked the Board to accept phased or risk-based alternatives, including SOC 2 Type I with a remediation plan, ISO 27001, or a NIST-based assessment. SEIA/CCSA/NJSEC also asked to apply utility operational-technology controls to EDC systems rather than small aggregators and that critical security provisions such as access control, encryption, secure development, vulnerability management, incident response, logging, data minimization, and vendor oversight, should be specified as mandatory requirements rather than guidance.

**Staff Response:** Staff appreciates the comments and notes that the Order anticipates a Board-administered aggregator licensing framework. Licensing, the shared-responsibility cybersecurity model, and baseline cybersecurity standards are among the market support structures to be developed through the PowerUp NJ Working Group over the next 30 months, where the scope of requirements and acceptable compliance methods can be considered.

### lxx. Advocacy Groups

Commenter(s) Referenced in This Summary: ACEEE, Ceres, CJNJ, Evergreen Action and EDF, NEEP, NJECN, NJEJA, New Jersey LCV, Sierra Club, and Vote Solar

ACEEE, Ceres, Evergreen Action and EDF, NEEP, and New Jersey LCV all asked for upfront or enhanced incentives for LMI customers. ACEEE asked that programs that overcome upfront cost be a priority from the start of the Interim Program. Evergreen Action and EDF asked for measurable LMI, overburdened community, and renter goals, no-cost or enhanced incentives through the Triennium, direct-install options, and community partners. New Jersey LCV asked for upfront battery incentives and for pairing community solar with battery aggregation so renters can take part. Ceres asked for simple enrollment and outreach to environmental justice

communities, and NEEP suggested free or reduced-cost devices and income-graduated fixed charges coupled with TOU rates. CJNJ, NJEJA, and Sierra Club requested binding equity targets, while Vote Solar recommended using an OBC adder through GSESP and developing subscriber-based, aggregation-eligible community storage and community solar-plus-storage models to expand VPP access. CJNJ asked for a standing utility deployment program in LMI and overburdened communities with a capacity target for each utility. NJEJA requested for each EDC and DER aggregator to file a quarterly Equity Performance Report, for an Independent Advisory Panel to be established, and for a requirement that at least 25% of enrolled VPP capacity in each territory be community-owned, and that license applicants show at least 30% of their portfolio in overburdened communities. Sierra Club asked for an equity floor with LMI enrollment targets, priority areas set with NJDEP, and lease-based pay with tenant protections, including for hosting equipment. Vote Solar asked for a Working Group equity workstream and rulemaking for community storage and solar-plus-storage.

**Staff Response:** Staff thanks the commenters for their feedback. As indicated in the Straw proposal, the VPP Interim program is just the first step in building out a robust market for storage and grid services. The long term VPP tariff, which is being advanced through the Grid Flexibility Services workstream (See BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) will provide parameters for participation. As mentioned in the PowerUp NJ straw proposal, there is a need to address specific use cases in the future to ensure a robust market that makes these services available to all ratepayers.

Evergreen Action and EDF, NJEJA, and Vote Solar all asked for equity and accountability data. Evergreen Action and EDF asked for data duties on both EDCs and aggregators, an annual VPP Cost Savings Scorecard, overburdened community and enrollment fields in the PSUP registry, risk-based insurance, a higher license fee, a standard disclosure label, and a Board-kept aggregator list. Vote Solar asked for an environmental justice tag, aggregator type, and device ownership type in the registry. NJEJA asked for a public GIS registry with ownership type and environmental justice status, updated quarterly and audited every two years.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that each EDC must report participation by LMI customers and customers in overburdened communities, along with enrolled devices

and kW by ZIP code and, where identified, on constrained circuits. Annual reports must include benefit-cost results using actual costs and verified savings. Staff intends that the DER registry field requirements, including the requirement for any equity-related fields such as those mentioned by the commenters, will be addressed through the PowerUp NJ Working Group.

Evergreen Action and EDF, NJECN, and Sierra Club all asked for strong cybersecurity and data protection. Evergreen Action and EDF asked that each party be accountable for the data it controls, with rules for data transfer, retention, and deletion, and that the standards be a floor with risk-based paths for items not ready at launch. NJECN and Sierra Club asked that EDCs build Grid and Edge DERMS with strong cybersecurity and that developers test for weaknesses during the Interim Program. NJECN also asked for IEEE 2030.5-2023, and Sierra Club asked for a standard data-sharing protocol such as Green Button. Evergreen Action supported the Straw Order's proposed three-tier data-access structure and associated cybersecurity standards, as this approach establishes appropriate access boundaries based on data sensitivity and customer consent.

**Staff Response:** Staff appreciates the commenters' feedback on requiring appropriate cybersecurity and data protection measures and agrees that this is a critically important aspect of the program. First, with respect to data sharing standards, these requirements are already being addressed in the recently adopted AMI rulemaking and in the Proactive System Upgrade Plan workstream (see BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*). Second, the PowerUp NJ Order itself only addresses technical requirements and it is Staff's intention that future discussions with the Power Up NJ Working Group will ensure that technical requirements continue to adapt to the shifting technology needs.

**lxxi. Program Implementers and Administrators**

Commenter(s) Referenced in This Summary: Ampion, Energy Solutions, MaGrann, Michaels Energy, and Power TakeOff

MaGrann, Michaels Energy, Power TakeOff, and Energy Solutions recommended targeted enrollment and outreach strategies for customers or market segments facing participation barriers. Michaels Energy recommended funding whole-building enrollment rather than limiting support to individual devices, treating outreach, site screening, and

engineering enablement as eligible implementation costs, and providing an enrollment adder or enhanced Pathway 1 payment to make small and medium-sized businesses in LMI and overburdened communities economical to serve. It also recommended using AMI screening to identify flexible small-business loads in overburdened communities and tracking their enrolled capacity and bill savings. Power TakeOff recommended that an EDC-contracted entity use AMI data to identify and recruit customers most likely to benefit from VPP participation, as an additional pathway alongside aggregator-initiated enrollment. MaGrann requested multifamily-specific program guidelines and mechanisms to better align incentives between property owners and residents in individually metered buildings. Energy Solutions recommended streamlined enrollment, transparent incentives, preferred-language materials, and consistent customer experiences across utility- and third-party-administered offerings to support participation and sustained engagement.

**Staff Response:** Staff thanks the commenters for their feedback on customer outreach. The Order requires that each EDC must describe how its program will reduce barriers for LMI customers and customers in overburdened communities, and its marketing plan must address known market barriers. The Order also allows each EDC to deliver its program through implementation contractors, which may include AMI-based customer identification. Further, each EDC's filing must include a marketing plan that explains how program services, incentives, and bill savings will be conveyed to customers. This marketing plan will also explain how the EDC will address known market barriers. Staff believes that it is more appropriate for the EDCs to have flexibility in implementing their own marketing practices in their respective territories; however, the Order does establish a common PowerUp NJ brand so that customers see one program identity across the component programs. Staff sees this balance of marketing/education/outreach ownership between the Board and the EDCs as appropriate given each EDC's existing touchpoints with their customers.

Ampion argued that the DER Registry was the only neutral entity within the Interim VPP framework acting as a check on settlement and double-counting. It suggested that device IDs, market participation flags, and settlement event references were necessary to keep self-settling aggregators honest. As to its proposed VSA framework, Ampion asked that these three (3) fields be added so that VSAs could populate data in standard format to prevent double-counting. Ampion also suggested that

its proposed settlement administrators could meet the cybersecurity standards as a condition of license, so that small aggregators could contract with a VSA instead of building their own systems.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order anticipates DER registries with common data fields to prevent double counting across compensation streams, to be developed through the PowerUp NJ Working Group. The Order does not establish a separate settlement administrator role for the VPP Interim Program.

### lxxii. Third-Party Suppliers

Commenter(s) Referenced in This Summary: Base Power and NRG

Base Power and NRG both opposed separate DER aggregator licensing for already licensed third-party suppliers. Base Power asked that supplier licensure govern where a supplier manages DERs only for its own retail customers without Board program payments, and that only non-duplicative elements apply otherwise. NRG asked that licensing not delay third parties that only aggregate DERs. Base Power also asked that supplier-enrolled DERs be included in the registry as soon as it is set up.

**Staff Response:** Staff appreciates the commenters' feedback on the requirement of an additional licensing process for third-party suppliers that are already licensed in the state of New Jersey. The Order does not establish aggregator licensing for the VPP Interim Program. The treatment of licensed third-party suppliers under the licensing framework, as well as the DER registry, will be considered as those structures are developed through the PowerUp NJ Working Group.

### lxxiii. Financial Services

Commenter(s) Referenced in This Summary: Syntropic

Syntropic asked for consumer protections for VPP equipment financing, including a separate agreement from the enrollment contract, plain-language disclosure of the contract's basic elements like rate, term, total cost, and cancelation, terms that do not raise the household's total monthly electricity cost, and Board oversight and complaint resolution. More broadly, it asked the Board to authorize third-party financing and on-bill repayment for equipment loans.

**Staff Response:** Staff thanks the commenter for their feedback. As described in the Order, the VPP Interim Program compensates customers for grid services and does not include equipment financing. Third-party financing and on-bill repayment are outside the scope of this Order, and the code of conduct anticipated in the Order is expected to address required disclosures and prohibited sales and enrollment practices.

**lxxiv. Individuals and Academic Institutions**

Commenter(s) Referenced in This Summary: Cammie Croft and Digital Verity

Cammie Croft requested for the MFR Order to set a binding LMI floor, modeled on the 51% LMI share in Community Solar, and an affordability band from 80% to 150% of area median income, with no upfront cost, debt, or clawback. The commenter further advocated that the LMI component utilize income verification by self-attestation or enrollment in programs such as USF, LIHEAP, and SNAP. Cammie Croft additionally suggested that, rather than utilizing opt-out enrollment, affirmative consent be required when a subsidized device is accepted, with advance notice before dispatch participation begins, exit at any time, and no fees. She also asked for SOC 2 Type II alternatives and licensing that fits nonprofits and public-benefit corporations, with financial assurance scaled to enrolled capacity.

**Staff Response:** Staff thanks the commenter for their feedback and recommendations on how PowerUp NJ can better serve LMI residents in New Jersey. Staff notes the VPP Interim program is just the first step in building out a robust market for storage and grid services. The long-term VPP tariff, which is already being worked on through the Grid Flexibility Services workgroup (see BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)* will provide parameters for participation. As mentioned in the PowerUp NJ Straw proposal, there is a need to address specific use cases in the future to ensure a robust market that makes these services available to all ratepayers. As the PowerUP NJ program transitions from the VPP Interim program to the long-term program and Staff continues to move the long-term VPP vision forward via the Grid Flexibility Services workgroup, Staff will keep equity concerns and feedback such as this in consideration.

Digital Verity asked the Board to fund an independent, university-hosted threat-modeling study of the distributed energy resource network created by the VPP Program, explaining that compliance standards alone do not identify potential attack paths to dispatch functions. It recommended conducting the study in parallel with implementation so that the findings could inform cybersecurity standards without delaying program launch. Digital Verity also requested that the study's findings be shared with the VPP Implementation Working Group and that Satya Vithala be added to the group for this subject matter.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order does not fund a separate threat-modeling study. Cybersecurity requirements, including a shared-responsibility model and incident reporting, are among the market support structures to be developed through the PowerUp NJ Working Group, which can consider findings such as these. Each EDC must also describe in its filing the cybersecurity controls and incident-response procedures for its dispatch systems. The Order establishes the PowerUp NJ Working Group to facilitate collaboration among stakeholders, and directs Staff to convene it upon approval of the EDC filings. Interested parties, including Digital Verity, may request to participate at that time.

## 10. Marketing, Timeline & Process

***Straw Proposal section(s):*** *§ 7.1–7.3, Section 8*; other issues under Stakeholder Comment No. 41

**Summary of Comments:** On marketing, most commenters supported a shared approach: the Board and EDCs provide neutral, program-level education, and aggregators market their own offers. The utilities wanted EDCs to keep a central education role, but opposed actively marketing aggregators and asked to list licensed aggregators on their websites instead. Most aggregators and advocates preferred post-distribution audits of aggregator materials over Board pre-approval, while ACE and ev.energy supported some pre-review. Several asked for outreach through community-based organizations and in multiple languages. On the timeline, the utilities, Rate Counsel, EEA-NJ, and NJUA stated that the schedule leaves too little time for review, procurement, and launch. PSE&G proposed EDC filings by February 1, 2027 and launch on October 1, 2027, and Rate Counsel asked for a procedural order with discovery. Many aggregators, trade associations, and advocates asked the Board to keep or speed up the schedule to meet PJM deadlines and capture federal tax credits. Commenters also asked for a more open process, interconnection improvements, and several provisions the Straw Proposal did not address.

**lxxv. Utilities and Utilities Association**

Commenter(s) Referenced in This Summary: ACE, JCP&L, NJUA, PSE&G, and RECO

ACE, JCP&L, NJUA, PSE&G, and RECO all stated that the proposed schedule is too tight and asked that milestones follow readiness. PSE&G stated that review, discovery, and settlement of four EDC filings cannot finish in five months, noting that EE filings get about seven months. It asked for EDC filings by February 1, 2027 and launch on October 1, 2027, with existing programs continuing under Triennium 2.5. RECO asked for MFR approval by March 1, 2027 so programs with fixed enrollment windows do not lose a season. NJUA stated that the VPP Interim Program is an entirely new statewide program rather than a routine transition between EE cycles, and that after Board approval utilities must still procure vendors, contract with aggregators, integrate platforms, enroll customers, and set up communications. It asked that existing DR and pilot VPP programs move into the VPP structure on the proposed schedule, with more complex elements, such as broader aggregator participation and expanded DER integration, on a later timeline, noting that experience in New Jersey and elsewhere shows that about one year is a more realistic timeframe for robust new VPP programs. NJUA also asked that foundational issues, such as target methods, baselines, wholesale market interaction, and evaluation criteria, be resolved before utility filings where practicable. ACE stated that a full procurement cycle takes longer than the schedule allows, and JCP&L asked for flexibility for each utility.

> **Staff Response:** Staff acknowledges the comments and notes that the Order revises the schedule. Each EDC must file its petition no later than February 12, 2027, and the VPP Interim Program will run from October 1, 2027 through September 30, 2029. Each EDC must provide an implementation schedule with key milestones, and may identify program elements it expects to develop after Board approval, provided it supplies those details to Staff before launching the affected sub-program.

ACE, PSE&G, and RECO all stated that EDCs should keep a central role in customer education. PSE&G stated that meeting the peak reduction targets will take substantial marketing spending. ACE and PSE&G both raised cost and endorsement concerns with requiring EDCs to market specific aggregators. ACE also requests that the Board lead high-level awareness messaging.

**Staff Response:** Staff appreciates the commenters' feedback and agrees that the EDCs should take the lead in educating their customers about the PowerUp NJ program and how customers can participate in the program. To ensure consistency across different services territories, the Order establishes a single PowerUp NJ name and branding standard, a marketing subgroup within the PowerUp NJ Working Group to coordinate efforts with the EDCs, and Board Staff-led public education before the programs open. Each EDC must file a marketing plan describing where and how the program will be promoted, including coordinated outreach with other utilities and its use of the PowerUp NJ name.

ACE, JCP&L, and RECO all asked for clear rules for aggregator marketing. ACE asked that materials referencing an EDC be approved by the utility in advance, as with EE trade allies, with periodic audits. RECO opposed Board pre-approval but asked that EDCs be able to set marketing standards and review materials. JCP&L asked that marketing accurately describe benefits, obligations, and data use, with aggregators accountable for accuracy.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that the code of conduct anticipated in the Order is expected to address required disclosures, prohibited sales and enrollment practices, and customer data usage restrictions, and will be developed through the PowerUp NJ Working Group. The future marketing subgroup of the Working Group will also coordinate marketing efforts with the EDCs.

PSE&G asked the Board to clarify its winter expectations, since PJM 5CP applies only in summer, and whether pay-for-performance behavioral DR, including opt-out designs, is eligible. It asked that the Interim Program allow new customer hardware under a regulatory sandbox, and that the long-term distribution tariff concept be discussed with the EDCs first.

**Staff Response:** The Order includes an option for including up to 10 calls for winter events as part of the 35 total events and provides EDCs with the option to add more dispatch events and requires a narrative to explain why such an expansion is needed. The VPP Interim Program is designed as a BYOD program for all eligible devices, except Storage which are addressed in the GSESP Block 1 portion of the Order.

**lxxvi. Division of Rate Counsel**

Commenter(s) Referenced in This Summary: Rate Counsel

Rate Counsel stated that aggregators should conduct most marketing and customer education. It recommended that the Board and EDCs post neutral VPP information and lists of approved aggregators online, and that EDCs not be required to distribute aggregator marketing materials.

**Staff Response:** Staff appreciates the comments and notes that the Order establishes a common PowerUp NJ brand and Board Staff-led public education so that customers receive neutral, program-level information. Each EDC must file a marketing plan for its program, and aggregator marketing practices are expected to be addressed through the code of conduct developed through the PowerUp NJ Working Group.

Rate Counsel stated that the five-month schedule is unworkable because each EDC filing requires full due process, and urged simple, flexible, market-based designs given PJM uncertainty. It acknowledged the Straw Proposal's procedural improvements but asked for a procedural order before the MFR Order. That order would include an issue-and-docket roadmap, a Staff response matrix, a technical conference, a revised MFR proposal with reply comments, discovery and Board findings on each EDC filing, and a separate later record for any long-term tariff. It cited New Jersey case law, the Board's BGS process, and practices in California, Maryland, and Connecticut. Rate Counsel offered its full comments as its response on issues not raised in the Straw Proposal.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order revises the schedule: each EDC must file its petition no later than February 12, 2027, and the VPP Interim Program will run from October 1, 2027 through September 30, 2029. Each EDC petition must be served on Rate Counsel and will be thoroughly reviewed by the Board before approval, and any long-term tariff will be developed through a separate straw proposal issued for stakeholder comment. Staff believes the process used to develop the Order, including the joint RFI, the Straw Proposal, and the written comment period, provided stakeholders adequate notice and opportunity to comment.

**lxxvii. Technology Providers (OEMs, DERMS Providers, Aggregators, etc.)**

Commenter(s) Referenced in This Summary: DCO, EnergyHub, ev.energy, Foley, Honeywell, Koolbridge, Logical Buildings, Oracle, Piclo, RExChain, Solar Landscape, Soltage, Steffes, Tesla, Turtle & Hughes, and Uplight

EnergyHub, Logical Buildings, Oracle, RExChain, and Uplight all addressed roles in education and outreach. Uplight asked for consistent statewide messaging from the Board, EDC use of their customer channels, and data-driven targeting rather than mass marketing. EnergyHub asked the Board to consider one statewide customer-facing VPP brand. Oracle asked the Board to encourage utilities and aggregators to integrate customer education, behavioral DR, and device-based offerings rather than market them as disconnected programs. It noted that customers may begin with behavioral actions and later enroll a smart thermostat, managed EV charger, battery, or other DER in a VPP program, while customers who do not wish to cede control of a device can still provide demand flexibility through behavioral DR. RExChain asked for coordinated education across TOU rates, VPP enrollment, solar/SREC incentives, and storage incentives. Logical Buildings asked that the aggregator be the main channel for event notices, opt-outs, and payments, with EDCs sending only required notices.

> **Staff Response:** Staff thanks the commenters for their feedback and notes that the Order establishes a single statewide PowerUp NJ name and branding standard so that customers encounter one program identity, along with a marketing subgroup to coordinate with the EDCs and Board Staff-led public education. Each EDC must describe in its marketing plan how program services, incentives, and bill savings will be conveyed to customers.

ev.energy and Solar Landscape both addressed review of aggregator marketing and contracting materials. Solar Landscape asked the Board to rely on standard disclosure rules and consumer-protection requirements rather than pre-approval, while keeping authority to act on misleading or otherwise non-compliant materials. ev.energy supported no-cost EDC distribution of aggregator materials and Board pre-review, with distribution timed to pre-summer and pre-winter campaigns.

> **Staff Response:** Staff acknowledges the comments and notes that the Order does not require Board pre-approval of aggregator materials. Required disclosures and prohibited sales and enrollment practices are expected to be addressed through the code of conduct developed through the PowerUp NJ Working Group, and the marketing subgroup will coordinate marketing efforts with the EDCs.

ev.energy, Piclo, Solar Landscape, and Tesla all asked the Board to keep or speed up the schedule. Piclo supported the proposed pace and indicated that the Q1 2027 tariff straw is the critical path item for third-party investment decisions and should not slip behind the Interim MFR settlement. Picolo stated that the October 2026 MFR Order deadline and PJM's December 1, 2026 notice deadline should be treated as hard deadlines. Solar Landscape asked the Board to move the long-term EDC tariff filing to Q4 2027 and set January 1, 2029, as a firm outside date for program launch. Tesla asked that launch not wait for Peak Shaving Adjustments, and that the Board urge PJM to update Manual 19 to allow Meter Generated Output for injecting resources. ev.energy asked the Board to confirm that aggregators can register with PJM independently of the state tariff order.

**Staff Response:** Staff appreciates the commenters' feedback and notes that each EDC must file its petition no later than February 12, 2027, and the VPP Interim Program will run from October 1, 2027 through September 30, 2029. Each EDC must also submit a PSA plan to PJM by September 10 of each year, beginning in 2027. Staff also notes that a VPP provider under these programs need not be registered with PJM, and PJM registration does not by itself qualify an entity to participate.

Honeywell and Turtle & Hughes both asked for clear implementation sequencing. Honeywell asked that the Interim Program move through readiness-based stage gates, from testing to limited operations to expansion, with each EDC filing its stage-gate plan. Turtle & Hughes asked that the VPP, GSESP, GridFlex, PSUP, AMI, and NEM reforms be run as one strategy, with implementation schedules and technical requirements published early.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that each EDC must provide an implementation schedule with key milestones from Board approval through program launch, and must provide Staff with any program details not included in its approved filing before launching the affected sub-program. Over the next 30 months, the EDCs are also expected to work with Staff on PSUPs, a GridFlex-based compensation tariff, and DERMS Tier 2 planning (See *BPU Docket No. QO24030199 In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid* and *BPU Docket No. QO26030059 In the Matter of Developing Grid Flexibility Services*

*for Aggregated DER Participation in New Jersey's Modernized Electric Grid).*

ev.energy, Soltage, and Turtle & Hughes all asked for interconnection improvements. Soltage reported study times of up to about 240 days in some EDC territories and asked for enforceable results from EDCs within six months and better pre-application reports. Turtle & Hughes asked that enrollment be coordinated with interconnection and commissioning to avoid duplicate submissions. ev.energy asked for EV-specific timelines that separate managed charging from generation interconnection, and for rules on multifamily sites with a shared meter.

**Staff Response:** Staff thanks the commenters for their feedback and notes that interconnection timelines and processes are outside the scope of this Order. Updates to distributed generation interconnection rules at N.J.A.C. 14:8-5 were adopted in January 2026 and Staff intends to recommend further updates to these rules in the near future.

DCO, Foley, Koolbridge, and Steffes all asked for paths to test or qualify resources not yet covered. Steffes proposed a pilot of 25 to 50 heat-pump homes with thermal storage, citing Sussex Rural Electric Cooperative's experience. Koolbridge asked the Board to recognize switching the electrical bus that serves a circuit as a source of peak reduction. DCO asked for a statewide assessment of about 100 potential CHP microgrid sites, and Foley asked for a working group with NJDEP to qualify on-site generators by equipment class rather than case by case.

**Staff Response:** The technology neutral framework envisioned in the Straw was designed as a Clean Energy technology neutral program which will likely grow as markets and technology expand. Staff notes that the Straw indicates that the VPP Interim program is just the first step in building out a robust market for storage and grid services.

Piclo asked that the marketplace function, including procurement/matching, qualification workflow, commitment tracking, and settlement support, be procured competitively as shared infrastructure across all four EDCs rather than four incompatible EDC-built portals.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order does not establish a shared marketplace across the EDCs. Each EDC must describe its aggregator solicitation plan in

its filing, and the PowerUp NJ Working Group provides a venue for the EDCs and stakeholders to work toward consistent practices.

**lxxviii. Trade Associations**

Commenter(s) Referenced in This Summary: Advanced Energy United, BTM Coalition, ChargEVC, EEA-NJ, NJCCC, SEIA/CCSA/NJSEC, and VGIC

BTM Coalition, ChargEVC, and SEIA/CCSA/NJSEC all asked the Board to move quickly. SEIA/CCSA/NJSEC proposed a schedule which laid out the following: a value-stack study and gap analysis in Q3 2026; a revised VPP straw with terms for existing BESS in Q4 2026; an order with MFRs for comprehensive grid services tariff in Q2 2027; utility tariff filings in Q3 2027; Board approval of tariffs in Q2 2028; launch of the Grid Services program in Q4 2028; and new projects operating by Q2 2029, so storage can use the federal tax credit before it expires in 2033 and before foreign-content limits raise costs. The BTM Coalition asked for a near-term, event-based program like ConnectedSolutions, accompanied by one storage program with appropriate performance-based compensation levels, instead of five pathways. ChargEVC asked for simple first steps that can be put in place quickly.

**Staff Response:** Staff appreciates the commenters' feedback and understands the need for long-term certainty which is why the long-term VPP program being built by the Grid Flexibility Services working group (BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid)* will provide an opportunity to compensate devices for their service to the grid. It is also why this Order requires a transition plan from the Interim program to the long-term tariff. Staff appreciates the schedule outlined by SEIA/CCSA/NJSEC, but flags that additional discussion is required before a full program to compensate grid services (long-term tariff) is developed into an order and anticipates putting forth a straw proposal of such before moving forward with an order. Staff understands, however, that the Board must move quickly with respect to developing a VPP program, which is why the current approach (Interim PowerUp NJ program launch via this Order, to be followed by a full grid service straw and subsequent order in 2027) has been taken.

NJCCC and SEIA/CCSA/NJSEC both asked for more open workgroups. NJCCC asked for published admission criteria, a broader Grid Flex

Workgroup, public materials, and more chances to comment. SEIA/CCSA/NJSEC asked that the Grid Flex group be open to anyone or, if not, that slides and call notes be published with an invitation for written feedback.

**Staff Response:** Staff appreciates the commenters' feedback and notes that the Grid Flexibility Services Workgroup is part of the Grid Modernization Forum BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*, and its process is technically outside the scope of this Order. Staff, however, is endeavoring to increase transparency into this workgroup's process as much as possible and flags that organization participation had to be capped to ensure adequate speaking time for all workgroup members. The PowerUp NJ Working Group, which is established by this Order, will facilitate collaboration among the Board, the EDCs, Rate Counsel, and relevant stakeholders. Staff is endeavoring to broaden stakeholder participation by running these workgroups but flags that it is infeasible to accommodate all parties' priorities via additional stakeholder opportunities (i.e. workgroups).

SEIA/CCSA/NJSEC and VGIC both asked for interconnection changes. SEIA/CCSA/NJSEC asked that EDCs model storage as it actually operates rather than under "worst-case-scenario" conditions, and that a proceeding be initiated to address interconnection reform as soon as possible. It also advocated for rate design and recommended that the Board initiate a proceeding or work through the Grid Flex workgroup to address retail rates for storage charging. VGIC asked the Board to direct EDCs to treat bidirectional EV charging as storage, apply interconnection only to grid-parallel discharge, and set certification paths for DC and AC systems.

**Staff Response:** Staff acknowledges the commenters' feedback and notes that interconnection requirements and retail rates for storage charging are outside the scope of this Order. Consistent with the Order, V2G-capable vehicles are treated as a form of customer-sited storage, and V2G compensation will be considered in the long-term framework.

EEA-NJ stated that the timeline is very ambitious and asked the Board to spread it out and align launches with summer and winter DR seasons.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order revises the schedule, as compared to the Straw proposal. Each EDC must file its petition no later than February 12,

2027, and the VPP Interim Program will run from October 1, 2027 through September 30, 2029, covering two summer seasons (June 1 through September 30) and two winter seasons (December 1 through the last day of February).

SEIA/CCSA/NJSEC suggested that standard disclosures may be pre-approved but that provider-specific claims be reviewed through post-distribution audits. It asked the Board to approve EDC plans for broad education while leaving customer recruitment to providers, and to coordinate quarterly outreach with community organizations.

**Staff Response:** Staff appreciates the commenter's feedback and notes that the Order directs Board Staff to begin a public education and requires each EDC to file a marketing plan, while aggregator disclosures and sales practices are expected to be addressed through the code of conduct developed through the PowerUp NJ Working Group. Each EDC must also show separately any costs of outreach to community-based organizations.

Advanced Energy United asked for contracts and tariff terms that let new DERs installed during 2027–2029 join the Interim Program, noting that its members install at least forty (40) residential batteries a week in New Jersey.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the VPP Interim Program allows additional devices to be added over the program period. Residential and small commercial BTM batteries, including newly installed systems, are served through Block 1, which provides incentives for up to 150 MW of new storage.

**lxxix. Advocacy Groups**

Commenter(s) Referenced in This Summary: ACEEE, Ceres, CJNJ, Evergreen Action and EDF, NJEJA, New Jersey LCV, Sierra Club, and Vote Solar

Evergreen Action and EDF, NJEJA, and New Jersey LCV all asked for outreach through community-based organizations. Evergreen Action and EDF asked that the Board and EDCs provide neutral education with community partners, recovered as administration costs, while aggregator advertising is not recovered from ratepayers. It asked for post-distribution audits rather than pre-approval. New Jersey LCV asked for sustained, multi-channel outreach through trusted messengers and targeted outreach

to past EE and DER program participants. NJEJA requests an extended comment window, two in-person workshops a year in each overburdened community, and program documents in ten languages other than English.

**Staff Response:** Staff acknowledges the comments and notes that each EDC must file a marketing plan that addresses known market barriers, describe how its program will reduce barriers for LMI customers and customers in overburdened communities, and show separately any costs of outreach to community-based organizations. The Order also calls for Board Staff to engage with relevant stakeholders on public education before the programs open. Staff will endeavor to increase the public's understanding of the PowerUp NJ program and advocate for the equitable distribution of information to the utmost extent possible.

Ceres, Evergreen Action and EDF, and Sierra Club all asked the Board to move quickly. Evergreen Action and EDF supported the timeline if each milestone has an enforceable date, a responsible party, and readiness requirements. Sierra Club asked the Board to meet or beat the schedule and coordinate with NEM reform, storage, utility business model reform (NJ Green Bank), Data Center Fair Share Act implementation, development of Community Benefit Agreement standards for data centers, and the Governor's Housing Governing Counsel. Ceres noted that other states are already scaling VPP programs. NJEJA and Vote Solar both asked for a more open process. NJEJA asked for at least a 90-day comment period on equity-related changes. Vote Solar asked that Grid Modernization Forum meetings follow New York's working group practices, with published schedules, virtual meeting links, agendas, notes, and membership. Vote Solar also asked the Board to reconsider the compressed NEM reform schedule. ACEEE cited the 2025 VPP Maturity Model and stated that the VPP Interim Program will enable New Jersey to transition from a Level 1 VPP (connected demand response) to a Level 2 VPP (enhanced demand response).

**Staff Response:** Staff appreciates the commenters' feedback. Per the Order, each EDC must file its petition no later than February 12, 2027, and the VPP Interim Program will run from October 1, 2027 through September 30, 2029. Each EDC must provide an implementation schedule with key milestones. The Order also coordinates the VPP Interim Program and Block 1 under the PowerUp NJ Programs and anticipates continued coordination with the Proactive System Upgrade

Planning and Grid Flexibility services work over the next thirty (30) months. The Board is endeavoring to work as quickly as possible, within reason, and increase transparency into its own and the EDCs' processes wherever possible. The NEM, Integrated Distribution of Distributed Energy Resources workgroup, and the Grid Flexibility services workgroup processes are all underway and Staff intends to keep the public updated via each proceeding's docket number (BPU Docket No. QO24090723 *In the Matter of Net Metering for Class I Renewable Energy Systems*, BPU Docket No. QO24030199 *In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*, BPU Docket No. QO26030059 *In the Matter of Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey's Modernized Electric Grid*) and on the Division of Clean Energy's website (https://cleanenergy.nj.gov/). With respect to ACEEE's feedback, staff appreciates the commenter's recognition of this advancement in New Jersey's VPP capabilities and is aware of EnergyHub's report of the VPP Maturity Model.

Ceres and CJNJ both asked for labor standards. Ceres asked for prevailing wages and workforce training, and CJNJ asked that utility-led deployment build a skilled union workforce. Evergreen Action and EDF, NJEJA, and Sierra Club all raised issues the Straw Proposal did not address. Evergreen Action and EDF asked for rules when an aggregator leaves the market, notice before Triennium 2 resources migrate, and a set process for tariff amendments. NJEJA asked for a Community Wealth Fund and a Community Capacity Building Fund, funded by 5% of VPP market revenues and 5% of the program budget, with community-led boards. Sierra Club asked Staff to study a publicly owned or anchored VPP with DCA, the Green Bank, EDA, HMFA, and NJDEP.

**Staff Response:** Staff thanks the commenters for their feedback and focus on adequate workforce development with appropriate wages. The Order currently requires the EDCs to provide a transition plan for Triennium participants to ensure that customers do not experience any gap in program implementation. Staff notes that the Straw indicates that PowerUp NJ's interim phase is just the first step in building out a robust market for storage and grid services, with further developments to come. The Program described in the Order is a compensation for grid services, there are no incentives beyond that compensation contemplated in this specific program.

**lxxx. Program Implementers and Administrators**

Commenter(s) Referenced in This Summary: Energy Solutions and Michaels Energy

Energy Solutions and Michaels Energy both addressed how marketing should be sequenced and targeted. Energy Solutions proposed three (3) phases: (1) broad education, (2) information on eligible programs and licensed aggregators, and (3) direct marketing by aggregators, OEMs, and vendors, subject to consumer protection rules. Michaels Energy stated that mass marketing will not recruit complex C&I sites and asked that EDC plans include AMI screening, feeder and substation data, coordination with account managers and existing efficiency programming, and engineering support. It also asked for a rolling technology qualification process.

**Staff Response:** Staff appreciates the commenters' feedback on marketing and customer education. The Order requires that each EDC must file a marketing plan that describes how the program will be promoted to each sector and how it will address known market barriers. Each EDC may deliver its program through implementation contractors, including for C&I customer outreach.

**lxxxi. Third-Party Suppliers**

Commenter(s) Referenced in This Summary: Base Power and NRG

Base Power asked that the MFR Order put in place the Data Center Fair Share Act reforms, including negative PLCs and Peak Shaving Adjustments, on a schedule that serves both laws. It also asked that a provider be able to choose a different pathway for different MW.

**Staff Response:** Staff appreciates the commenters' feedback and recognizes that there are opportunities for collaboration between the PowerUp NJ program and the VPP called for in the Data Center Fair Share Act. Staff notes that the PowerUp NJ program development process precedes the Data Center Fair Share Act's passage and that alignment has been made where possible. Staff notes that the Order directs the EDCs to develop plans to revise their PLC calculation and reporting methodologies to account for negative PLC by no later than February 12, 2027.

NRG asked for one statewide framework so customers and providers face one set of rules rather than four.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that the Order establishes a single PowerUp NJ program with

uniform MFRs for all EDCs, including common dispatch parameters and common benefit and cost line items. The Order does allow appropriate flexibility, where necessary, in implementation as to not be overly prescriptive and onerous in its requirements for the EDCs.

### lxxxii. Financial Services

Commenter(s) Referenced in This Summary: Syntropic

Syntropic asked to be added to the service list for Docket No. QO26030099.

**Staff Response:** Staff thanks the commenter and notes that all information will be posted in relevant docket numbers listed in this Order. Staff will endeavor to add Syntropic to relevant service lists moving forward.

### lxxxiii. Individuals and Academic Institutions

Commenter(s) Referenced in This Summary: Bill Beren, Cammie Croft, Michael Winka, and Peak+

Michael Winka and Peak+ both asked for public education. Michael Winka recommended that the Board manage public outreach through neutral partners such as NJIT, Rutgers, or Sustainable Jersey rather than leave it to DER manufacturers or aggregators. He also suggested that outreach explain why events are called in order to lower complaints and opt-outs. Peak+ asked that public education on load management be the first step, noting that many people may not understand the need for load management or how to participate. Peak+ also identified that there could be barriers to participation through a lack of willingness or technology affordability.

**Staff Response:** Staff appreciates the commenters' emphasis on customer education and agrees that awareness and understanding of the program are critical to its success. As such, the Order calls for coordinated educational outreach on the PowerUp NJ program, with consistent branding for all programs. Each EDC will be responsible for marketing the specific details of their program, but Staff intends to work closely with the EDCs to ensure brand and information consistency across different service territories.

Cammie Croft asked for open solicitation windows published in advance, for example twice a year.

**Staff Response:** Staff acknowledges the commenter's feedback and notes that each EDC must describe its solicitation plan in its filing, including a timeline that allows selected aggregators to begin enrollment, which will be subject to Board review.

Bill Beren criticized the Board's history of rulemaking delays, citing the medium- and heavy-duty EV make-ready tariff proposals, and asked the Board to streamline its rulemaking schedule to meet the proposed program deadlines.

**Staff Response:** Staff acknowledges the commenter's feedback on the medium- and heavy-duty EV proceedings and is working to ensure that rulemakings via associated proceedings come to fruition in coordination with the PowerUp NJ program. Staff will continue to move these workstreams in parallel rather than in sequence to ensure timely implementation.

# Attachment D

In the Matter of Establishing the PowerUp New Jersey Program, Docket No. QO26100658

In the Matter of Advancing a Virtual Power Plant (VPP) Program in the State of New Jersey Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program – Phase 2 Distributed Storage, Docket No. QO26040116

On August 17, 2026, Board Staff released the Draft Garden State Energy Storage Program ("GSESP") Phase 2: Distributed Energy Storage Capacity Block 1 Straw Proposal ("Straw Proposal"). Staff received oral comments at a public stakeholder meeting on September 3, 2026, and accepted written comments through September 10, 2026. The Board received a final count of sixty-eight (68) comment submissions, consisting of forty-six (46) written submissions and twenty-two (22) oral submissions. This total reflects submissions rather than unique commenters because some entities participated through both written and oral comments, and certain joint written submissions represented multiple aligned organizations.

Staff reviewed and considered all written and oral submissions and organized the comments into sixteen (16) topic areas reflecting the issues that generated the most substantive stakeholder feedback. The body of this attachment begins each topic area with a brief description of its scope and organizes the comments by commenter category, summarizing the principal themes, recommendations, concerns, and material differences reflected in the record. Because some submissions addressed multiple subjects, a comment may be reflected in more than one topic area where it provides distinct substantive information. Within each commenter-category subsection, "Commenters Referenced in This Summary" identifies the commenters expressly named in that summary. The list serves as an attribution aid and is not an exhaustive list of every commenter who addressed some aspect of the topic: omission from the list does not indicate that a submission was disregarded or excluded from Staff's review. The summaries do not address every statement or separately name every commenter who raised the same or a substantially similar point. Staff's responses address the material issues presented in the record, including issues summarized collectively.

The commenters who submitted written or oral comments, organized by commenter category, are identified below:

Categories of stakeholders:

Utilities: Electric distribution companies ("EDCs") and gas distribution companies ("GDCs")

1. Atlantic City Electric ("ACE")
2. Jersey Central Power and Light ("JCP&L")
3. Public Service Electric and Gas Company ("PSE&G")
4. Rockland Electric Company ("RECO")
5. New Jersey Natural Gas ("NJNG")

The Division of Rate Counsel

6. The Division of Rate Counsel (“DRC”)

Technology providers, aggregators, developers, and Original Equipment Manufacturers (“OEMs”)

7. Bluesky Utility NoFar USA
8. BTM Coalition (Tesla, Sunrun, Goodleap, igssolar, EnergyHub, Enphase)
9. Energy Hub
10. Every Electric Inc.
11. Koolbridge Energy
12. Lunar Energy
13. Mainstay Energy
14. Nexamp
15. Outlast Power
16. Powerflex
17. Prologis
18. Rexchain
19. RIC Energy
20. Solar Landscape
21. Soltage
22. Trinity Solar
23. Uplight
24. Voltus
25. Weave Grid
26. Xura
27. BTM Coalition (Tesla) - Dominic Gatti
28. RExChain - Siddika Pasi
29. Trucurrent - Yiming Zhong
30. CleanPeak Energy Group - Ed Levene
31. Mainstay Energy - Ajay Surie
32. Energy Hub - Miriam Fuchs
33. BTM Coalition (Sunrun) - Thad Culley
34. Powerplex - Jacqueline Piero
35. Trinity Solar - Kenneth Ebbert
36. Base Power - Jackson Parell

Trade associations

37. Advanced Energy United
38. Clean Peak Energy Group
39. Energy Efficiency Alliance
40. Joint Clean Energy Parties (New Jersey Solar Energy Coalition, Solar Energy Industries Association, and Coalition for Community Solar Access; collectively “JCEP”)
41. Mid-Atlantic Solar & Storage Industries Association (“MSSIA”)
42. New Jersey Clean Capacity Coalition

43. New Jersey Clean Energy Ventures
44. Public Power Association of New Jersey
45. Vote Solar
46. Vote Solar - Elowyn Corby
47. NJ Solar Energy Coalition - Fred DeSanti
48. Mid-Atlantic Solar and Storage Industries Association - Lyle Rawlings
49. New Jersey Environmental Justice Alliance (Solar Energy Industries Association) - Georgina Arreola-Lennox
50. New Jersey Environmental Justice Alliance (Solar Energy Industries Association) - Joan White
51. Advanced Energy United - Chloe Holden
52. ChargEVC-NJ - Pamela Frank

Environmental, consumer, and environmental justice organizations

53. Cammie Croft
54. Climate Jobs NJ
55. New Jersey Environmental Justice Alliance

Program implementers, consultants, and academic commenters

56. Base Power
57. Don Whitley
58. Ecological Systems LLC
59. Individual - Mary Ellen Hennessy-Jones
60. Individual - Michael Winka
61. Individual - Peter Fried
62. Solar United Neighbors
63. Syntropic Capital Partners
64. Individual - Stanislav Jaracz
65. Individual - Don Whitley
66. Individual (electrician) - Yehuda Chazon
67. Individual - Curtis Aubry
68. Individual - Mark Chopping

The commentors' feedback was categorized into the following topics:

1. **Eligibility.**
2. **Incentive Levels**
3. **Existing Resource Participation**
4. **Block Size**
5. **Dispatch Events**
6. **Net Energy Metering ("NEM")**

7. **Benefit Cost Methodology**
8. **Performance Factor Methodology**
9. **70% Passthrough Requirement**
10. **Distributed Energy Resource Management Systems (“DERMS”) Ecosystem**
11. **EDC Recovery**
12. **Interconnection**
13. **Overburdened Communities (“OBCs”)**
14. **Interoperability with Other Virtual Power Plant (“VPP”) Programs**
15. **EDC Control of Storage Systems**
16. **Alternative Dispatch, Measurement and Verification (“M&V”)**

Board staff have gone through all commentors’ feedback and have summarized the comments by each topic. Comment summaries are further organized by each individual category of stakeholders, for all applicable commenters. Staff responses to comments are provided below by topic area:

# 1. Eligibility

**Summary of Comments:** Stakeholders addressed the customer classes, resource types, ownership and participation structures, rate schedules, and BTM or FTM configurations that should qualify for Block 1, including the potential participation of small-commercial and other C&I customers.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE, JCP&L, PSE&G, RECO, and NJNG

Regarding the classes of customers and resources that should be eligible, the utilities differed on the appropriate breadth of eligibility. ACE recommended that eligibility criteria address interconnection status, device-level controllability, minimum telemetry capabilities, and customer consent and disclosures. JCP&L supported beginning with a focused implementation while preserving the ability to refine eligibility criteria based on Block 1 experience. NJNG supported clear eligibility rules for new residential BTM storage. PSE&G recommended consolidating the GSESP and VPP pathways into a single program for BTM resources and stated that it was prepared to administer Block 1 for any customer category approved by the Board.

Regarding existing batteries, ACE described GSESP as a mechanism for accelerating the deployment of new BTM storage and the VPP framework as the mechanism for compensating storage and other DERs for grid services. ACE therefore recommended that the Board clearly define the eligibility distinctions and transition pathways between new and existing BTM resources.

Regarding C&I, FTM, and BTM resources, the utilities principally addressed BTM participation, with their C&I recommendations focused on small-commercial customers. JCP&L recommended preserving utility-owned FTM storage as a future deployment option where customer-sited resources cannot reliably address identified distribution-system needs. NJNG separately recommended that future program designs evaluate how storage could interact with solar, fuel cells, and other inverter-based technologies to support dispatch duration, resiliency, and system performance during prolonged grid-stress events.

Regarding small-commercial participation, JCP&L recommended including small-commercial customers, while PSE&G stated that it was prepared to serve any customer category approved by the Board. ACE supported small-commercial participation where resources provide incremental and

measurable grid benefits not already captured through existing tariffs. RECO similarly recommended limiting participation to rate structures under which battery dispatch produces incremental benefits for the broader rate base. ACE recommended value-stacking, M&V, and other safeguards to ensure incentives compensate for distinct and verifiable services. RECO proposed a maximum eligible battery size and a dedicated small-commercial funding cap so that residential and similarly sized small-commercial systems could participate on comparable terms while preventing larger installations from disproportionately consuming available funding. More broadly, JCP&L recommended permitting customers to combine GSESP incentives with Board-approved financing and other DER, VPP, or grid-flexibility offerings, provided that the same service is not compensated twice.

**ii. DRC**

DRC did not oppose distributed energy storage as a resource class, provided a resource can be shown to address an identified system capacity or resource need, perform reliably at the time and location of that need, and produce measurable and verifiable net savings for New Jersey customers. DRC further questioned relying solely on residential-sales allocations and first-come, first-served enrollment and recommended consideration of competitive or least-cost selection mechanisms as an alternative. Where distribution-system benefits are claimed, DRC recommended identifying constrained areas before enrollment and using measures such as capacity reservations, locational weighting or adders, minimum locational eligibility for part of the block, or targeted solicitations. It acknowledged that first-come, first-served enrollment could remain available for capacity justified principally by statewide capacity or transmission savings.

DRC cautioned that a new ratepayer-funded DER program should produce incremental value and that Block 1 should not merely relabel existing demand-response resources or enable migration between programs without new participation, capability, or benefits. It stated that failing to ensure those outcomes would create program “free riders.” To address overlapping compensation, DRC recommended one ratepayer-funded compensation pathway by default and, where cross-program participation is permitted, dollar-for-dollar offsets for overlapping compensation, a cap on total ratepayer-funded compensation at the resource’s verified incremental value, and a resource-level registry and compensation ledger tracking payments, revenues, obligations, and applicable time periods.

DRC did not oppose considering small-commercial storage in a later or separately analyzed phase, but recommended against adding another

customer class to Block 1 without distinct cost-effectiveness and tariff analyses. DRC stated that, if eligibility is expanded to small-commercial customers, each EDC should identify the eligible rate schedules, the private value available under each tariff, the incremental obligation purchased by the incentive, and the effect on non-participating customers. It explained that some customers may already capture demand-charge, capacity, transmission, or time-of-use value through bill management and should not receive an additional ratepayer-funded payment for the same value. DRC requested a separate small-commercial Benefit Cost Analysis ("BCA"), customer-class bill-impact analysis, and compensation ledger before enrollment. DRC did not otherwise address a broader C&I or FTM eligibility framework.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: Bluesky Utility/Nofar USA; BTM Coalition; EnergyHub; Every Electric; Koolbridge Energy; Mainstay Energy; Nexamp; Outlast Power; PowerFlex; Prologis; RExChain; RIC Energy; Solar Landscape; Soltage; Trinity Solar; Uplight; Voltus; Xura; BTM Coalition/Tesla–Dominic Gatti; RExChain–Siddika Pasi; Trucurrent–Yiming Zhong; CleanPeak Energy Group–Ed Levene; PowerFlex–Jacqueline Piero; and Base Power–Jackson Parell

Technology commenters generally supported expanding eligibility beyond residential BTM resources, although they differed over sequencing and allocation. EnergyHub, Outlast Power, RExChain, Xura, Ed Levene, and Siddika Pasi supported small-commercial participation in Block 1, with several recommending dedicated allocations or system-size thresholds. PowerFlex proposed opening eligibility first to small C&I, and then broader C&I if residential enrollment is insufficient. Conversely, Prologis supported immediate eligibility for all C&I facilities. Mainstay Energy, Voltus, and Yiming Zhong emphasized a defined and timely general C&I pathway rather than one confined to critical facilities, while the BTM Coalition supported separate capacity allocations to prevent other project scales from displacing residential resources. Xura also advocated for defined C&I-scale BTM storage in the near-term, as well as the Block 1 eligibility of small non-residential systems. Bluesky Utility/Nofar USA separately asked whether future capacity blocks would extend eligibility to C&I locations.

Several commenters supported additional resource configurations and ownership models. Nexamp, RIC Energy, and Solar Landscape sought a near-term, segment-specific pathway for distribution-connected FTM storage rather than requiring those projects to wait for residential Block 1 implementation. Similarly, Soltage urged the Board to prioritize a FTM

distribution storage program in Block 2. Every Electric proposed eligibility for non-exporting plug-in batteries serving renters and multifamily residents, Dominic Gatti and Jacqueline Piero urged consideration of V2G resources, and Bluesky Utility/Nofar USA asked whether a multifamily EV-charging and battery system serving residential premises could qualify for GSESP when the system takes service under a non-residential tariff. EnergyHub, Mainstay Energy, and RExChain supported third-party-owned ("TPO") participation, while Uplight supported the inclusion of third-party-supply customers. Similarly, Ed Levene sought pathways for fixed-price third-party-supply customers, qualified aggregators, and/or third-party suppliers. Jackson Parrell supported third-party supplier access to incentives crediting BTM storage for distribution system value. Outlast Power supported TPO participation, and also recommended that the Board consider portfolio-level enrollment.

The BTM Coalition and Dominic Gatti emphasized avoiding a deployment pause between release of the Straw Proposal and the opening of Block 1 and supported transition treatment for systems installed during that period. Trinity Solar similarly asked whether systems installed after release of the Straw Proposal but before the program opens could subsequently enroll. The BTM Coalition specifically recommended eligibility for systems applying for Permission to Operate after release of the Straw Proposal. It also identified a participation gap for batteries installed before the Straw Proposal because the Interim VPP did not yet provide a storage pathway, even though those systems are already interconnected and capable of providing the same device-level performance as new systems. Uplight separately recommended that existing VPP batteries and newly installed GSESP batteries operate under a common framework for resource registration, availability, dispatch, M&V, and grid-service compensation, with the long-term VPP tariff ultimately layered onto that architecture.

Several technology commenters opposed using a customer's rate class, supplier choice, or receipt of private bill savings as a categorical bar to participation. EnergyHub, Mainstay Energy, Outlast Power, Prologis, Solar Landscape, Uplight, Voltus, and Xura generally recommended compensating distinct, measurable grid services while accounting for any duplicative value. Koolbridge Energy recommended a tariff-specific assessment under which a rate class would either be excluded or receive adjusted compensation reflecting only the incremental benefit delivered. RExChain supported excluding rate classes under which customers already capture the full value of avoided wholesale energy, capacity, and transmission charges and recommended reserving approximately 20 to 25 MW of Block 1 for small-commercial participation. The central

disagreement was therefore whether rate-related duplication should be addressed through rate-class exclusion or adjustment of compensation, not whether qualified small-commercial batteries can provide grid value.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; EEA-NJ; Joint Clean Energy Parties; MSSIA; New Jersey Clean Capacity Coalition; NJR Clean Energy Ventures; Public Power Association of New Jersey; Vote Solar; Advanced Energy United–Chloe Holden; Vote Solar–Elowyn Corby; SEIA–Georgina Arreola-Lennox; and ChargEVC-NJ–Pamela Frank

Trade associations broadly supported preserving residential BTM Block 1 while establishing timely C&I participation. Clean Peak Energy Group, EEA-NJ, JCEP, MSSIA, Vote Solar, Advanced Energy United, Georgina Arreola-Lennox, and Pamela Frank supported small-commercial or broader C&I eligibility. JCEP and EEA-NJ favored an expanded block or dedicated commercial allocation that would not displace residential resources, while MSSIA and Advanced Energy United urged an expedited general C&I pathway not limited to critical facilities. Vote Solar supported eligibility across small-commercial rate structures, subject to monitoring participation between residential and commercial customers and between OBC and non-OBC areas to ensure equitable participation. JCEP proposed a more tailored approach under which compensation would be adjusted where a tariff already provides substantially all of a particular benefit, while preserving payment for distinct capacity, transmission, distribution, reliability, or other grid services. Clean Peak Energy Group specifically supported customers served under fixed-price third-party-supply contracts. Chloe Holden and Pamela Frank also supported the inclusion of V2G.

The associations also supported broadening eligible resources and participation arrangements. Advanced Energy United, JCEP, the New Jersey Clean Capacity Coalition, and NJR Clean Energy Ventures advocated a parallel pathway for distribution-connected FOM storage, with NJR Clean Energy Ventures emphasizing storage added to existing wholesale solar facilities and their available sites, infrastructure, and interconnection rights. Advanced Energy United and ChargEVC-NJ supported V2G resources; Vote Solar proposed subscription-based community-storage models serving renters and multifamily residents through FOM or C&I projects, including pairings with community solar; and the Public Power Association of New Jersey sought participation by municipal electric utilities and the State's cooperative utilities. Advanced Energy United also suggested that the Board define a pathway for third-

party suppliers. The prevailing position was that residential BTM, C&I BTM, and FTM storage require coordinated but potentially distinct program structures.

Trade associations also generally supported a pathway for existing batteries. Advanced Energy United favored participation by both existing and new residential systems, while Vote Solar and Elowyn Corby supported allowing existing resources to earn performance compensation through GSESP or the VPP without counting them toward GSESP's new-capacity target. Clean Peak Energy Group proposed expedited approval for systems seeking Permission to Operate, and expedited interconnection for systems of 50kW or less. JCEP suggested that the Board permit Block 1 eligibility for existing DERs seeking post-straw Permission to Operate, rather than directing those applicants towards other programs in development. The principal distinction was between deployment incentives intended to induce new capacity and compensation paid to existing resources for verified grid services.

**v. Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft, Climate Jobs New Jersey, and the New Jersey Environmental Justice Alliance

These commenters primarily treated eligibility as an equity, access, community ownership, and workforce issue. Cammie Croft supported a bounded community-benefit reserve for Low-to-Moderate Income ("LMI") households, including renters and multifamily residents, as well as small-commercial eligibility for resident-serving premises such as nonprofit-owned multifamily housing, community centers, and houses of worship. NJEJA recommended requiring at least 25% of GSESP Phase 2, Block 1 capacity in each EDC service territory to be owned directly or through a controlling interest by qualifying community entities, including cooperatives, municipal utilities, community land trusts, locally governed nonprofits, and OBC-based community aggregators. Climate Jobs New Jersey did not propose another customer class but recommended requiring eligible resources to be VPP-compatible and installed and serviced under uniform licensing, safety, compliance, and apprenticeship standards.

Croft did not expressly support or oppose legacy-battery participation but supported ratepayer incentives targeting additional deployment and households not served by the existing market. She also supported applying the exclusion for supply rates that pass through wholesale charges to qualifying small-commercial participants where the premises serve residents. Neither Climate Jobs New Jersey nor NJEJA substantively

addressed existing-battery eligibility or small-commercial rate exclusions. The group's collective emphasis was therefore that expansion into BTM, C&I, or FTM storage should broaden access and community benefits rather than reproduce existing disparities or displace residential participation.

**vi. Program implementers, consultants, and academic commenters**

Commenter(s) Referenced in This Summary: Base Power, Ecological Systems LLC, Mary Ellen Hennessy-Jones, Michael Winka, Peter Fried, Solar United Neighbors, Syntropic Capital Partners, Don Whitley, Curtis Aubry, and Yehuda Chazon

These commenters generally supported targeted eligibility expansion but proposed different customer and tariff boundaries. Solar United Neighbors and Yehuda Chazon supported small-commercial participation, with SUN emphasizing nonprofit community-service providers that could serve as resilience centers and recommending a limited carve-out that preserves residential customers as the principal focus. Michael Winka supported small-commercial customers on fixed tariffs but recommended excluding demand-charge C&I customers from the interim program because they can already monetize battery operation through demand-charge savings. Base Power instead proposed separating value streams, allowing customers or suppliers already capturing capacity and transmission savings to receive only the distribution-value portion of the GSESP incentive rather than excluding the entire resource.

Base Power, Solar United Neighbors, and Syntropic Capital Partners supported eligibility across different ownership and financing structures. Base Power recommended that customers served by third-party suppliers remain eligible for Block 1 and that the supplier be eligible to serve as the participant only for the distribution-value portion of the incentive, excluding capacity and transmission value already realized through wholesale accounting. Solar United Neighbors supported equal participation by TPO resources, while Syntropic Capital Partners emphasized accommodating homeowner-owned and debt-financed systems alongside TPO and aggregation models. Collectively, these commenters favored eligibility rules that accommodate different ownership and financing structures while avoiding duplicative compensation.

Michael Winka was the only commenter in this category to directly address existing batteries. He supported eligibility for existing residential and small-commercial systems because they could immediately contribute capacity and support VPP and distribution-system-operator development, while recommending a reduced incentive to recognize their sunk capital costs.

The remaining commenters did not establish a broader category-wide position on legacy-resource eligibility.

**Board Staff Response:**

Staff acknowledges the comments concerning eligibility and recommends limiting Block 1 eligibility to behind-the-meter residential and small-commercial customers eligible for BGS-RSCP, whether taking BGS or third-party supply. Staff acknowledges DRC's concern about expanding program eligibility to small commercial customers, but concludes on the basis of the comments favoring expanding eligibility to small commercial customers that the benefits of doing so exceeds the drawbacks. In particular, Staff believes that the Block 1 program's high all-ratepayer benefit-cost ratio and modest incentive levels counsel in favor of allowing broader eligibility to ensure sufficient capacity to meet program targets can be enrolled as quickly as possible, thereby maximizing savings to ratepayers. Expanding eligibility to small commercial customers also addresses EDC concerns, noted in the Block Size section below, that it may be difficult to enroll 150 MW of new BTM energy storage capacity if eligibility is limited to residential customers only. Similarly, Staff further believes that the administrative costs and enrollment barriers created by drawing and enforcing fine eligibility distinctions between different kinds of small commercial customers will outweigh the potential benefits of targeting incentives only to those small commercial customer classes that provide the highest BCR for other ratepayers. The costs of additional EDC administrative expenses as well as higher capacity and transmission costs from delayed resource deployment are also borne by ratepayers, and must be weighed when choosing whether to chase the theoretically perfect design.

Conversely, Staff believes DRC's concerns justify excluding large C&I customers from Block 1, as a far greater percentage of such customers likely are on or have access to pass-through rates that already allow them to monetize the benefits of using BTM storage as peak reduction tools. Allowing such customers to receive the same Block 1 incentives as residential and small commercial classes would likely reduce the all-ratepayer program BCR substantially.

Staff agrees with DRC that ratepayer funding should procure measurable value that is not already compensated through another program or market. Staff has recommended that Third-party-owned and TPS-affiliated structures are permitted, subject to anti-duplication to enable robust participation while avoiding overpayment. A resource may not receive duplicate compensation for the same capacity, availability, dispatch, or interval performance.

Staff acknowledges DRC's request to consider competitive program design principals. However, Staff does not recommend competitive procurement, a locational reservation, or a statewide compensation ledger as a condition of Block 1 enrollment. Block 1 is intended to establish a uniform initial program and develop comparable information regarding enrollment, costs, performance, and realized benefits. The MFRs nevertheless require tariff, bill-impact, BCA, compensation, and performance information sufficient to evaluate the concerns raised by DRC. Staff notes that the Block 1 program is designed as a pay-for-performance program which rewards actual performance of enrolled systems. Further, Staff notes that the incentive level was set below the modeled level expected to be needed in an effort to avoid over-incentivization as an alternative to a competitive procurement. Running competitive procurements for the number of projects expected to reach enrollment of 250 MW of residential and small commercial installations would necessitate significant staff time and resource costs to administer.

Moreover, DRC itself acknowledged that Block 1's "first-come, first-served" design would be appropriate if Block 1 is primarily justified by avoiding capacity and transmission costs. That is exactly the case here. As the Block 1 BCA results in Attachment H demonstrate, projected distribution benefits account for only a small fraction of total projected benefits and the all-ratepayer BCR is well above 1.0 even if distribution benefits are assumed to be zero.

Staff further acknowledges the request to create locational based mechanisms to target deployment. Staff has recommended an intentionally simplistic design for Block 1 which is designed to achieve the bulk of benefits through capacity and transmission savings in lieu of an overly complicated construct designed on distribution benefits which are anticipated to be a small percentage of overall program benefits. Staff anticipates it will be easier to implement a more sophisticated approach in the future by gaining practical experience from operating Block 1 rather than attempting to immediately design and implement the perfect approach.

Staff acknowledges the concerns about compensation for resources that are already installed, but Staff notes that the program uses a pay-for performance design. Moreover, incentive levels have been further reduced for existing resources to reduce the risk of overcompensation while still providing some mechanism for resources currently sitting idle to dispatch during times of grid needs. Indeed, Staff's BCA modeling also showed that $100/kW-year incentive is well below the actual value BTM storage discharge provides, even in areas where the battery

provides zero distribution value and only helps avoid capacity and transmission costs.

Staff also considered concerns that compensating existing batteries may create free riders. Existing resources, however, can provide near-term, otherwise unused dispatch capability at a lower incentive rate and without requiring ratepayers to fund another installation. Crucially, neither existing nor new storage resources can receive both the Block 1 incentive and compensation from a demand response program or PJM wholesale markets, either as in individual resource or as part of an aggregation. This also means that a resource already committed to another program for the same service must complete or terminate that obligation before enrolling in Block 1 and receiving compensation from Block 1 for that service. When combined with the paucity of existing options for BTM energy storage to monetize the value they can provide to the grid, these safeguards render the risk of free ridership minimal. Accordingly, Staff recommends allowing up to 100 MW of existing storage to participate at $100/kW-year, subject to the same performance, technology, measurement, and anti-duplication requirements as new resources. The reduced rate reflects the absence of an incremental installation cost while purchasing new availability and verified performance during the program term.

Staff acknowledges multiple commenters request to provide some pathway for municipal and cooperative utilities to participate in the Block 1 program. Though Staff agrees that there is value in municipal and cooperative utility storage programs, Staff believes the Block 1 design is ill-suited to municipal and cooperative utility participation. First and foremost, the funding mechanism for Block 1 are the ratepayers of the Board-regulated and investor-owned EDCs. Municipal and cooperative utility customers will not bear any of the costs of the Block 1 program. Consequently, allowing municipal or cooperative utilities or their customers to participate in the program raises cross-subsidization concerns. Even if those were set aside, there would be significant practical questions about how to transfer the necessary funds, as the Block 1 design is built around the premise that each EDC will fund the implementation of its Block 1 program from its own ratepayers. Similarly, the Board lacks jurisdiction over municipal and cooperative utilities and thus cannot require them to act as Block 1 program administrators, which poses another significant practical challenge to integrating them into Block 1 as potential administrators. Furthermore, to the extent commenters are requesting that the Block 1 program provide funding for municipal or cooperative utility-owned storage, that is simply out of the program's scope. The Block 1 program

is exclusively designed to be a pay-for-performance program for non-utility owned BTM energy storage.

Staff also notes that that municipal and cooperative utilities have the power to develop their own versions of the Block 1 program funded by their own ratepayers. As municipal and cooperative utilities are not regulated by the Board, they do not need the Board's permission or to wait for any Board action to do so. The results of Staff's Block 1 BCA indicate their ratepayers would likely see net benefits from such a program. Indeed, cooperative and municipal utilities' ability to create their own likely net-beneficial programs funded by their own ratepayers heightens Staff's fundamental fairness concerns with requiring EDC ratepayers to cross-subsidize such programs in addition to funding their own EDCs' programs.

However, Staff stresses that its concerns about allowing municipal and cooperative utility participation is limited to Block 1. It is also due to Block 1's specific design and funding source. If Block 1 was a grant program financed by general State or Federal funds rather than a pay-for-performance program funded by EDC ratepayers, Staff agrees it would be entirely appropriate to allow municipal and cooperative utilities or their ratepayers to access it on the same terms and conditions as EDCs or their ratepayers. As such, Staff and the Board may well consider participation pathways for municipal and cooperative utilities in future blocks or other storage programs.

Staff appreciates the substantial interest in broader C&I, FTM, LMI, community-ownership, V2G, and other resource pathways. Staff does not recommend incorporating those additional segments into Block 1 beyond BGS-RSCP-eligible small-commercial customers. The initial design prioritizes a simple, implementable program that can deliver broadly shared capacity and transmission savings while limiting near-term program cost and administrative complexity. Later GSESP capacity blocks or other Board proceedings may address additional customer classes, ownership structures, technologies, and locational services based on the operational, cost, and participation data developed through Block 1.

## 2. Incentive Levels -

**Summary of Comments:** Stakeholders addressed the appropriate incentive amount and the costs, revenues, risks, performance obligations, customer benefits, and market conditions relevant to determining or adjusting that amount.

### i. Utilities

Commenter(s) Referenced in This Summary: ACE, JCP&L, PSE&G, and RECO

The utilities did not collectively provide explicit support for increasing the $200/kW-year base incentive. Generally, ACE and PSE&G instead favored upfront incentives, front-loaded, or hybrid assistance, with PSE&G specifically suggesting targeted support for LMI customers. ACE also suggested modestly higher compensation for resources providing advanced telemetry, control, or interoperability capabilities, while ACE and JCP&L recommended reviewing the initial incentive based various data points such as transparent technology-cost assumptions, participation, program performance, affordability, market conditions, and/or cost-effectiveness. Alternatively, RECO recommended retaining the $200/kW-year performance payment and adding a one-time incentive of approximately $2,000–$3,000 per system.

The principal utility rationale for supplemental compensation was that high upfront purchase and installation costs could suppress participation and jeopardize achievement of the Block 1 deployment target, particularly for LMI customers. RECO also questioned whether the Straw Proposal's federal tax-credit assumptions accurately reflect current residential economics. The utilities generally treated these concerns as support for targeted adders, upfront assistance, or subsequent recalibration, not as justification for a uniform increase in the statewide base rate.

**ii. DRC**

DRC found that the straw proposal did not demonstrate that the proposed $200/kW-year incentive was necessary or appropriately calibrated. If the Board proceeds with an administratively established Block 1 rate, DRC recommended setting the rate no higher than $200/kW-year and treating that amount as a maximum rather than a spending target or precedent for later blocks. It estimated that full enrollment of 150 MW at that maximum could expose ratepayers to approximately $30 million annually and $300 million in nominal incentive payments over ten years, excluding administrative and enabling costs.

DRC criticized Staff's revenue-gap analysis for modeling time-of-use arbitrage as the sole project revenue stream while excluding potential capacity, transmission, wholesale-market, distribution-service, future VPP, and private-resilience value. Although it recognized a reasonable basis for discounting speculative future revenues when establishing an initial incentive, DRC maintained that the original revenue gap should not permanently justify the full incentive if additional revenues later materialize

and are retained by participating owners or aggregators. It recommended distinguishing between the revenue certainty needed to establish the Block 1 market and a guarantee that all later value streams would accrue in addition to the original incentive. As an alternative, DRC recommended incorporating uncertain future value streams through administratively determined discounting factors.

DRC recommended that future incentive levels be informed by actual Block 1 experience, including installed costs, financing assumptions, tax incentives, tariff savings, participant and aggregator costs, wholesale and VPP revenues, subscription pace, attrition, dispatch performance, administrative costs, and realized capacity, transmission, and distribution value. It favored market-based price discovery for later blocks through competitive solicitations, auctions, descending-price mechanisms, or comparable processes and recommended that compensation increasingly follow verified performance as program experience develops. Where projects subscribe readily at the maximum rate, storage deployment meets program goals, or additional revenue streams become available, DRC recommended reducing future incentive levels to avoid over-subsidization and mitigate ratepayer affordability burdens.

DRC emphasized the value of regulatory certainty for properly approved Block 1 contracts and recommended addressing subsequent market changes prospectively rather than through retroactive repricing. To limit the precedent established by Block 1, it recommended annual financial and performance reporting, a formal Board review before authorizing any subsequent block, hard annual and cumulative budget caps, and reconciliation of authorized and actual expenditures. DRC also recommended one ratepayer-funded compensation pathway by default and, where overlapping participation is permitted, dollar-for-dollar offsets for overlapping compensation and a cap on total ratepayer-funded compensation at the resource's verified incremental value.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; EnergyHub; Lunar Energy; Prologis; RExChain; Solar Landscape; Soltage; Voltus; Xura; RExChain–Siddika Pasi; EnergyHub–Miriam Fuchs; and CleanPeak Energy Group–Ed Levene

Technology commenters were divided between retaining the proposed rate with structural improvements and increasing the underlying incentive. Lunar Energy supported $200/kW-year over ten years, supplemented by targeted income, equity, and locational adders, while the BTM Coalition and

EnergyHub generally agreed with the $200 rate but recommended applying it to average verified delivery rather than reducing payments through the proposed minimum-output Performance Factor. Prologis recommended $300/kW-year for C&I resources, and Siddika Pasi recommended $300/kW-year more generally. Miriam Fuchs and Ed Levene supported considering an unspecified higher rate. RExChain requested a reconciled gap analysis before fixing the value, Soltage suggested that the rate should be based on average dispatch across events, and Xura emphasized an administratively-set, durable, financeable rate with a performance component reflecting the capacity, transmission, and distribution value delivered.

Commenters supporting additional compensation cited financing and revenue gaps, substantial capital costs, limited private-resilience value for C&I customers, and assumptions that residential customers can obtain time-of-use savings that may not actually be available. Several also argued that the minimum-output Performance Factor and EDC-defined event duration could reduce realized payments far below the nominal rate. Other commenters viewed payment design and revenue certainty—not the headline incentive alone, as the central concern: Voltus emphasized value stacking to support capital and operating costs, Solar Landscape argued that greater EDC control over storage dispatch should be matched with greater compensation certainty, and Lunar Energy favored targeted adders where resources provide additional equity or locational value.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Joint Clean Energy Parties; Vote Solar; Advanced Energy United; Clean Peak Energy Group; New Jersey Clean Energy Ventures; MSSIA; Vote Solar–Elowyn Corby; New Jersey Solar Energy Coalition–Fred DeSanti; and Advanced Energy United–Chloe Holden

Several trade associations recommended higher compensation but differed on the amount and structure. The Joint Clean Energy Parties recommended $250 per average delivered kW-year, followed by a review after six months of enrollment, while Vote Solar and Fred DeSanti recommended $300/kW-year. Because NJSEC participated in JCEP's written $250 recommendation while its verbal representative recommended $300, both positions remain part of the record. Advanced Energy United supported an increase without specifying a value.

Other associations proposed alternatives to a uniform increase. Clean Peak Energy Group recommended evaluating the payment a

representative battery would actually receive after application of the Performance Factor. Alternatively, New Jersey Clean Energy Ventures emphasized compensation sufficient to close the financing gap. MSSIA proposed a fixed annual payment per kWh over approximately 10–15 years based on a tiered performance structure.

The stated justifications included long customer-payback periods, substantial capital and financing costs, reduced realized payments under the Performance Factor, and the backup capability or operational flexibility customers surrender during Dispatch Events. Vote Solar and Advanced Energy United also connected higher compensation to a greater number of Dispatch Events and the additional capacity, transmission, and ratepayer value those events could provide, while several commenters compared the proposal with higher-paying programs in other states. Vote Solar and Elowyn Corby separately supported upfront assistance for storage serving OBCs, distinguishing targeted equity support from a general increase for all participants.

v. **Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft; New Jersey Environmental Justice Alliance

The comments emphasized targeted incentive design rather than an across-the-board increase in the base incentive. Cammie Croft proposed implementing a community-benefit reserve and modified project-readiness requirements without increasing the base incentive, while observing that a fixed ten-year incentive commitment could provide meaningful financing value. She also stated that nonprofit or community ownership and elective-pay tax treatment may reduce the financing gap relative to conventional third-party ownership. The New Jersey Environmental Justice Alliance recommended a 10% social multiplier for resources located in high-energy-burden census blocks, based on the additional resilience, public-health, locational, and equity benefits of those projects and the need to address historical underinvestment.

vi. **Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power, Ecological Systems LLC, Michael Winka, Solar United Neighbors, Stanislav Jaracz, Syntropic Capital Partners, and Mark Chopping

The commenters proposed differentiating compensation based on financing and ownership structures, available value streams, location, and resource characteristics. Syntropic Capital Partners requested separate

revenue-gap modeling for homeowner-owned, debt-financed systems, arguing that their financing gap may exceed the modeled $300/kW because homeowners may not receive the depreciation and federal tax benefits assumed for third-party-owned portfolios and because the Performance Factor may reduce actual payments. Base Power recommended a lower distribution-only incentive for third-party suppliers that can capture capacity and transmission value through wholesale accounting. It proposed calculating that rate by multiplying the $200/kW-year Block 1 rate by the share of total quantified system benefits attributed to avoided distribution investment. Michael Winka recommended reduced incentives for existing resources, higher locational incentives where storage could defer infrastructure upgrades or increase hosting capacity, and the eventual phaseout of incentives as storage becomes cost-effective and market-based compensation develops.

Other commenters proposed alternative payment structures. Ecological Systems LLC recommended a market-linked Clean Peaker Parity Tariff compensating capacity and additional services such as energy absorption and voltage response, citing battery-cycling and degradation costs borne by customers. Stanislav Jaracz recommended kWh-based monthly payments, Mark Chopping proposed higher compensation for solar-charged storage than for fossil-charged storage, and Solar United Neighbors prioritized a simple and transparent pay-for-performance structure permitting the payment of participant compensation directly to aggregators without identifying a specific value. Collectively, these comments treated financing conditions, tax treatment, locational benefits, uncompensated grid services, and resource characteristics as grounds for differentiated compensation rather than an across-the-board increase.

**Board Staff Response:**

Staff acknowledges disagreement over incentive design and specifically DRC's position that $200/kW-year should be a maximum incentive, not a spending target, guaranteed payment, or precedent, while other commenters favored higher incentives. In light of the mixed comments on this topic, Staff has recommended to retain the incentive level established in the Straw Proposal for the comments concerning incentive levels and recommends maximum incentives of $200 per kW for 150 MW of new storage and further recommends establishing a $100 per kW maximum incentive level for 100 MW of existing storage, each for a ten-year performance-based term and subject to the same performance and technology requirements. The lower existing-storage incentive recognizes that those resources have already incurred installation costs. EDC filings and annual reports shall provide the cost, enrollment, attrition, delivered-performance, and payment information

required by the MFR. Staff also reiterates that these are recommended *maximum* incentive levels; actuals will depend on verified discharge and a participating resource's Performance Factor.

Staff's specific reasons for recommending these incentives values are as follows. First, though Staff refers to Block 1 payments as "incentives" for ease of reference, they are intended to be payments for the actual value efficient BTM energy storage dispatch provides to the grid and act as a transitional mechanism to market-based compensation. Second, the Block 1 program is explicitly designed to help address the ongoing electricity affordability crisis by producing net reductions in electricity costs to customers. To ensure those two design criteria are met, Staff favors keeping the incentives at a level that results in a modeled all-ratepayer BCR of well over 1.0, even in sensitivity cases with low capacity prices or no distribution-level savings. This makes it highly likely that Block 1 will deliver net savings to ratepayers and not overpay for energy storage dispatch even if Staff's assumptions about avoided capacity and transmission costs or program administration expenses prove overly optimistic. Staff likewise believes that the longer tenor and greater total budget commitment for the Block 1 program as compared to the VPP Interim program demands a greater BCR cushion.

Block 1's cost reduction objective means that having an incentive level that drives a robust market response is an important consideration, but it is not the only consideration. This is why Staff did not solely base its recommended incentive levels on the results of its gap analysis. Rather, Staff chose an incentive level that appeared both capable of driving resource deployment and enrollment while also providing a high likelihood of net savings to all ratepayers. To that end, Staff also considered empirical data showing that many New Jersey residential customers have decided to invest in BTM energy storage for private resilience reasons absent any pay-for-performance revenue stream. This provides important evidence that an incentive level that many commenters believe may be too modest will drive a sufficient market response to make Block 1 successful. By establishing an overly modest incentive, Staff has addressed DRC's concern that using administratively determined incentives which have limited price discovery opportunities would lead to the potential to over incentivization. Conversely, Staff concludes that many commenters' concerns about the sufficiency of the incentive level and the high BCR the currently proposed incentive levels counsels against a lower recommended incentive. Furthermore, the recommended incentives are smaller than comparable storage incentives in programs in other

states, indicating they constitute a modest starting point and should not be reduced further.

Staff further acknowledges DRC's criticism of the revenue-gap analysis, but believes this criticism is unfounded. DRC appears to assume that BTM energy storage resources could simultaneously receive Block 1 incentives and wholesale market revenue. This is simply incorrect. For the reasons explained below in the Benefit Cost Methodology section, it is a threshold eligibility requirement that Block 1 resources do not participate in any PJM wholesale market. Similarly, anti-duplicative compensation rules for the Block 1 program will prevent Block 1 resources from earning duplicative compensation for the same service from other Board programs. Thus, in order to access most of the future revenue streams that are of concern to DRC, a BTM energy storage resource would have to first exit the Block 1 program and forfeit Block 1 incentive payments. There was thus no reason to include wholesale market or duplicative revenue streams in the gap analysis.

Staff acknowledges that it is possible Block 1 resources could earn additional revenue for providing services for which Block 1 incentives do not compensate. However, Staff believes it is appropriate to allow such revenue to be stacked with Block 1 revenue. This follows from the fact that Block 1 incentives do not cover the full revenue gap, use a pay-for-performance design, and are calibrated to be less than the actual value storage discharge provides to grid. It is therefore economically efficient to allow BTM energy storage resources to earn additional revenue for providing additional services in the future.

Staff agrees with DRC on the need to provide incentive certainty in Block 1, and that Block 1 incentive levels should not establish a precedent or a presumptively reasonable incentive level for future Blocks. Staff will closely monitor uptake rates, in addition to tracking system costs, to track and validate incentive levels in order to make recommended adjustments for future blocks as needed.

Staff acknowledges calls for up-front incentives given the high total installed and upfront costs for storage systems. However, Staff notes that potential third-party ownership models are a frequent feature of similar programs and can obviate the need for a Host Customer themselves to pay a large upfront cost to install storage. While Staff does not recommend any specific ownership model, Staff notes, that such arrangements also enable monetization of the remaining available investment tax credits which in turn lowers the cost of storage to the Host Customer. Furthermore, upfront incentives are inconsistent with the Block 1 design objective of only providing payments to energy storage systems that deliver actual value to the grid and ratepayers.

This approach thus ensures that performance and attrition risk lie with the participating resource, rather than ratepayers generally.

Finally, Staff acknowledges commenters' requests for alternative payments structures and targeted incentive adders, as well as requests for additional values to be compensated in Block 1. Staff recommends against implementing these suggestions at this time to preserve program simplicity and limit program costs but may consider them in future blocks.

## 3. Existing Resource Participation

**Summary of Comments:** - Stakeholders addressed whether previously installed batteries should have a participation pathway and how compensation for those resources should relate to incentives intended to support new storage deployment.

### i. Utilities

Commenter(s) Referenced in This Summary: Atlantic City Electric ("ACE")

ACE characterized GSESP as a market-development program intended to accelerate the deployment of new BTM storage through financial incentives and the VPP as the operational framework through which storage resources and other DERs would provide grid services and receive compensation. ACE recommended that the Board clearly distinguish eligibility requirements for new and existing BTM storage, differentiate installation incentives from performance-based grid-services compensation, and establish coordinated participation pathways across GSESP, the VPP Interim Program, and GridFlex. ACE further recommended using GSESP incentives to support the purchase and installation of new BTM storage and subsequently enabling those resources to enroll in the VPP under clearly defined eligibility and participation requirements.

### ii. DRC

DRC recommended that ratepayer-funded DER programs produce new participation, capability, and measurable incremental capacity-resource value rather than merely relabel existing demand-response resources or facilitate movement between programs without corresponding new benefits.

DRC recommended establishing a resource-level registry and compensation ledger before Block 1 enrollment begins. The ledger would track GSESP incentives, VPP and demand-response payments, other EDC and Board program incentives, public and tax-supported assistance, tariff savings, wholesale revenues, aggregator payments, and other ratepayer-funded compensation, together with the specific obligation and applicable period associated with each payment. DRC proposed using this information to determine whether claimed services are incremental, separately measurable, operationally compatible, and worth more to ratepayers than the combined compensation paid to obtain them, as well as to account for later-arising revenues and resource migration between programs.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; Uplight; Trinity Solar; BTM Coalition (Tesla) – Dominic Gatti; Trinity Solar – Kenneth Ebbert

The commenters generally agreed that batteries installed before Block 1 opens should not be left without a pathway to provide compensated grid services, but they did not establish a common position that all legacy systems must participate directly in GSESP. The BTM Coalition emphasized that existing batteries are already interconnected and capable of providing the same device-level performance as new systems. Uplight similarly viewed existing and GSESP-supported batteries as operationally comparable once installed and recommended common registration, dispatch, M&V, and grid-services compensation standards across GSESP and the VPP or Edge DERMS framework. The BTM Coalition, Trinity Solar, Dominic Gatti, and Kenneth Ebbert also recommended a safe harbor for systems installed, or applying for permission to operate, between release of the Straw Proposal and the opening of Block 1.

Uplight distinguished the deployment incentive associated with a resource's enrollment pathway from compensation for its subsequent delivery of grid services. It recommended that existing batteries participating through the VPP and newly deployed GSESP batteries use the same performance-measurement and grid-services compensation methodology when they provide equivalent services,

thereby supporting consistent treatment of verified performance across the two programs.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Vote Solar; Vote Solar – Elowyn Corby; ChargEVC-NJ – Pamela Frank; Joint Clean Energy Parties ("JCEP")—SEIA, NJSEC, and CCSA; Clean Peak Energy Group

Advanced Energy United, Vote Solar, Elowyn Corby, and Pamela Frank generally supported providing qualified existing batteries with a pathway to earn compensation for grid services, reasoning that excluding operational resources would leave available capacity unused. Advanced Energy United expressly recommended allowing both existing and new residential systems into Block 1. Vote Solar supported a standardized pathway through GSESP or the VPP framework and recommended that existing resources be permitted to provide services without counting toward GSESP's new-capacity target. JCEP focused more narrowly on avoiding a deployment pause by extending eligibility to systems installed, or applying for permission to operate, after the Straw Proposal or Board Order but before enrollment opens. Clean Peak Energy Group differed by recommending that enrollment open by March 1, 2027, to permit a full quarter for installation, and expedited inspection and Permission to Operate.

The applicable trade associations generally distinguished incentives intended to induce new installations from payments earned for verified grid performance. Vote Solar and Advanced Energy United supported compensating existing resources for services provided but did not expressly recommend that all existing batteries receive the same dollar-per-kW-year deployment incentive as new resources. JCEP and Clean Peak Energy Group did not propose a separate incentive rate for transition-period systems. The trade-association record therefore supports an existing-resource participation pathway but does not establish a common position on identical incentive levels.

**v. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: Cammie Croft

Cammie Croft stated that the proposed commercial-operation-date screen would distinguish projects based on timing but would not establish whether the incentive caused a battery to be installed or whether the project would have proceeded without the program. She cautioned that compensating projects already planned or otherwise likely to proceed would provide less incremental value to ratepayers and recommended a community-benefit reserve with modified project-readiness requirements to direct a portion of Block 1 toward projects that could expand access and deployment.
Croft distinguished the question of whether an existing battery might provide compensable grid services from whether it should receive the full incentive intended to induce new deployment. Generally, her comments caution against automatically extending the new-resource incentive to existing or otherwise non-incremental resources.

**vi. Program implementers, consultants, and academic commenters**

Commenter(s) Referenced in This Summary: Michael Winka

Michael Winka supported allowing existing residential and small-commercial batteries to participate in the performance-based program. He reasoned that these systems could immediately enlarge the participating resource base, contribute available capacity, and support the development of a VPP and distribution-system-operator market.

Michael Winka expressly opposed compensating existing batteries at the same rate as newly installed resources. He recommended a significantly reduced incentive for existing systems because their installation costs are already sunk, while still allowing them to earn performance-based compensation for services provided. He did not propose a specific reduced dollar amount or calculation methodology.

**Board Staff Response:**

Staff acknowledges and appreciates the support for operational batteries. Staff agrees that existing resources require clear treatment and recommends that 100 MW of existing storage be

eligible for a ten-year performance-based term at $100/kW-year, subject to the same technology, operating, measurement, and performance requirements as new resources. Staff agrees with DRC that existing resources should be paid only for new, measurable capability and not for an overlapping obligation. The $100/kW-year maximum purchases incremental availability and verified performance rather than sunk installation cost; an existing overlapping dispatch or compensation obligation bars Block 1 payment for the same service. Staff suggests that through participation in Block 1, existing and otherwise idle and unused capacity resources can be most readily deployed at reduced cost to support the Program goals of reducing the zonal capacity obligation. An existing resource already subject to a continuing dispatch obligation or receiving compensation for the same service may not also receive Block 1 compensation for that same obligation. Each EDC filing shall describe the contractual and systems controls it will use to identify continuing dispatch obligations and prevent simultaneous compensation for the same service. The reduced incentive purchases incremental availability and verified performance during the program term; it does not reimburse sunk installation cost.

Staff acknowledges DRC's request for a comprehensive resource registry and notes that remains an important feature of the mid-term VPP program as described in the Order, with an expectation that efforts on this will commence through a stakeholdering process during the next 30 months. The Block 1 Interim Report will also contemplate whether the establishment of a registry is necessary.

However, Staff disagrees with DRC that the establishment of such a registry should be a precondition to the launch of Block 1. The time it takes to establish such a registry could materially delay the implementation of Block 1 and by extension the savings it provides to ratepayers. As noted above, Block 1 also has several built-in safeguards against duplicate compensation that lessen the near-term importance of such a registry. Furthermore, except for several EDC pilot programs whose incentives cannot be stacked with Block 1, there is currently no mechanism for actively dispatching or incentivizing BTM batteries to reduce zonal capacity obligations and provide near-term capacity

savings to New Jersey ratepayers. Consequently, Staff believes the lost ratepayer savings from delaying the launch of Block 1 would outweigh the benefits of having a DER registry at program launch.

## 4. Block Size

**Summary of Comments: -** Stakeholders addressed the appropriate initial MW award, the allocation of that capacity, and the performance, enrollment, cost, or market conditions that should inform future capacity blocks.

**i. Utilities**

Commenter(s) Referenced in This Summary: PSE&G; JCP&L; RECO

PSE&G characterized the existing target as ambitious and potentially difficult to achieve through residential participation alone, and suggested that non-incentivized utility-scale investment could supplement GSESP deployment to meet State targets. JCP&L requested additional analysis supporting the proposed MW target, and a mechanism to adjust it should actual adoption differ materially from forecasts. RECO similarly recommended treating deployment milestones as nonbinding and proposed a service-territory goal of 4 MW by summer of 2030, contingent on approved programs, available funding, and customer adoption.

**ii. DRC**

DRC emphasized the financial consequences of the proposed 150 MW capacity commitment, estimating that full enrollment at the maximum $200/kW-year incentive could expose ratepayers to approximately $30 million annually and $300 million in nominal incentive payments over ten years, excluding administrative and enabling costs. It criticized allocating the block based on residential sales and enrolling resources through an administratively established, first-come, first-served process without competitive price discovery or a sufficiently developed showing of system need, costs, expected benefits, and ratepayer savings.

DRC recommended tying capacity commitments to identified system needs and measurable ratepayer value. For capacity expected to provide distribution benefits, it recommended requiring each EDC to identify constrained areas before enrollment, including the relevant constraint, forecast timing, conventional investment potentially avoided or deferred, estimated project cost, required kW reduction, duration and timing of the need, forecast load growth, and minimum performance required to support deferral. DRC proposed reserving capacity for constrained areas, applying locational weighting or adders, establishing minimum locational eligibility

for part of the block, or conducting targeted solicitations. It stated that first-come, first-served enrollment could remain available for capacity justified principally by statewide capacity or transmission savings, while capacity receiving distribution-value credit should be targeted to documented needs and reflected in EDC capital planning.

DRC recommended treating Block 1 as a disciplined opportunity to obtain actual cost, participation, and performance information before making further capacity commitments. It requested a formal Board review before authorizing any subsequent block, considering subscription pace, enrollment and attrition, installed costs, incentive and administrative expenditures, customer and aggregator retention, dispatch performance, available revenues, capacity and transmission value, distribution deferrals, bill impacts, market conditions, and lower-cost alternatives. It further recommended requiring affirmative Board action for any additional block based on updated need, market conditions, incentive requirements, actual Block 1 performance, and demonstrated ratepayer savings.

DRC also recommended hard annual and cumulative budget caps and annual reconciliation of authorized and actual expenditures, installed and delivered MW, performance factors, and net benefits. It recommended returning or crediting unspent or unsupported balances rather than automatically rolling them forward and conditioning additional capacity on demonstrated cost-effectiveness rather than satisfaction of an enrollment target. Where actual results fall materially below the approved showing, DRC recommended preserving the Board's authority to reduce future block sizes, lower incentive levels, suspend new enrollment, require an updated filing, disallow imprudent expenditures, redesign the program, or decline future blocks. DRC emphasized that program success should be measured by verified net customer savings after accounting for incentives, administrative expenses, enabling investments, and alternative opportunities, rather than by MW enrollment alone.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: Prologis; BTM Coalition; Every Electric; PowerFlex; RExChain; Voltus; CleanPeak Energy Group–Ed Levene; and RExChain–Siddika Pasi

Prologis proposed a 300 MW block if all C&I facilities are included, reflecting the larger systems those customers can support. Voltus also recommended C&I inclusion, questioning the reduction from the VPP Straw Proposal's referenced 350 MW of BTM storage to 150 MW and suggesting closing that gap through concurrent C&I participation. Still, Voltus did not

suggest a specific Block 1 cap. RExChain–Siddika Pasi similarly questioned whether 150 MW is realistic for a residential-only program, but did not recommend a particular alternative total.

Other commenters were not necessarily opposed to the 150 MW objective, but urged the Board to consider changes to who participates or how capacity is counted in order to meet the goal. PowerFlex recommended using enrollment milestones and opening the block progressively to small and larger C&I customers if residential installations are not on track to fill it; RExChain proposed reserving approximately twenty (20) to twenty-five (25) MW of the existing block for small-commercial resources; and CleanPeak Energy Group–Ed Levene expressly supported the 150 MW goal. The BTM Coalition focused on the denominator, recommending that capacity reservations reflect expected sustainable delivery, customer backup reserves, and event duration rather than inverter nameplate capacity, so that a nominal 150 MW award produces approximately 150 MW of usable grid flexibility. Similarly, Every Electric supported altering the definition of Awarded Storage Capacity to reflect deliverable capacity, rather than inverter nameplate.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Vote Solar; Clean Peak Energy Group; Joint Clean Energy Parties; Energy Efficiency Alliance; Advanced Energy United–Chloe Holden; Vote Solar–Elowyn Corby; and Solar Energy Industries Association–Georgina Arreola-Lennox

Advanced Energy United recommended increasing the cap to 300 MW, reasoning that the existing block could fill before the long-term VPP becomes available and that 150 MW of enrolled nameplate capacity may provide only approximately 50 MW during multi-hour events. Vote Solar recommended at least 250 MW, citing the limited time remaining to achieve New Jersey's 1 GW distributed-storage target by 2030. Elowyn Corby likewise supported a block substantially larger than 150 MW, while Chloe Holden supported an increase without specifying an amount.

Other trade associations supported retaining or supplementing the existing allocation. Clean Peak Energy Group supported the 150 MW objective, while the Joint Clean Energy Parties recommended preserving the full 150 MW residential allocation and adding capacity through either an expanded Block 1 or a separately identified small-commercial tranche. The Energy Efficiency Alliance similarly recommended limiting commercial participation to a percentage of each EDC's allocation to preserve residential access.

Vote Solar, Elowyn Corby, and Georgina Arreola-Lennox additionally recommended counting actual deliverable or export capability rather than nameplate capacity so that the block reflects the MW available to provide grid services.

**v. Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft

Cammie Croft recommended using demonstrated customer demand to determine additional residential capacity. She proposed that oversubscription of Block 1 open a second residential block sized according to the waitlist and incorporating the same community-benefit reserve. Within the initial 150 MW block, she recommended reserving a modest share of each EDC's allocation for community-benefit projects, with the reserve size determined by Staff and unused capacity reverting to the general queue after a defined period. If applications exceed the remaining capacity during the final enrollment week, she recommended allocating that capacity pro rata among applicants or capping reservations per applicant to prevent a single large portfolio from taking an EDC's remaining allocation.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power

Base Power did not take a position on the appropriate initial MW award, but noted the change between the up to 350 MW proposed in VPP Straw Proposal and the GSESP Block 1 proposal's 150 MW target. To that end, Base Power recommended that the MFR Order reconcile those figures. Base Power also recommended preserving the ability to open additional capacity promptly if Block 1 subscribes rapidly, rather than predetermining a larger initial award.

**Board Staff Response:**

Staff acknowledges the comments concerning program scale and recommends an initial block of 150 MW of new storage and 100 MW of existing storage in an effort to deploy a significant volume of new residential and small commercial systems and make use of otherwise idle existing systems. This size is intended to produce meaningful statewide operating experience and potential capacity and transmission benefits while limiting ratepayer exposure during the initial block. Staff acknowledges Block 1 will provide key programmatic learnings to be leveraged through subsequent capacity blocks, should the Board determine they are appropriate.

Staff believes Staff's recommendation to expand Block 1 eligibility to small commercial customers addresses the EDCs' concerns that it might not be feasible to meet the 150 MW target solely with residential BTM energy storage.

With respect to DRC's concerns about setting a 150 MW administrative target to be filled on a first-come, first-served basis with a process to tie incentives to distribution system needs, Staff reiterates that the Block 1 program targets and is primarily justified by avoided capacity and transmission benefits. DRC itself acknowledges that such an approach is appropriate for a program focused on avoiding bulk-system costs. As shown in Attachment H, even when assuming no distribution system benefits the state-wide lifetime all-ratepayer BCR for Block 1 is still 1.76. The small distribution-level savings in the base case are heavily discounted but positive to account for the likelihood that a fraction of Block 1 capacity will be deployed in locations where it can also provide distribution-level benefits.

Staff also believes that it would be difficult to either gather the baseline data needed to inform future price discovery and potential blocks focused on meeting distribution system needs absent an initial Block 1 target of 250 MW. Observing how fast Block 1 capacity enrolls will provide data on whether future incentive levels should be lower or higher. The 250 MW target is also large enough that it should result in enough BTM energy storage capacity on constrained circuits to provide the EDCs with some initial experience in dispatching BTM energy storage to meet distribution level constraints. This will provide critical, real-world data on the locational value BTM storage can provide as well as the challenges in leveraging BTM storage for this purpose. That data and experience will in turn aid the design and implementation of future blocks focused on providing value to the distribution system.

Conversely, Staff believes DRC's concerns counsel against expanding the size of Block 1 as several commenters suggested. While Staff is confident that Block 1 will provide net benefits to ratepayers, the administratively set nature of the Block 1 incentives means neither the Board nor Staff can know whether the Block 1 incentive level is the most cost-effective incentive level. It is possible that the Block 1 incentive levels will ultimately prove to be higher than necessary and that a lower incentive could have provided ratepayers with even greater net savings. Maintaining a modest but meaningful block size of 150 MW of new storage capacity and 100 MW of existing storage capacity limits this risk and allows for price discovery before the Board commits to incentives levels for future and potentially larger blocks. In short, Staff believes the 250 MW Block 1 target strikes a reasonable balance

between the benefits of quickly securing a meaningful amount of BTM storage capacity and the risks of over-incentivizing that capacity.

Similarly, Staff agrees with DRC that subscription alone does not establish cost-effectiveness or ratepayer savings. Enrolled nameplate capacity must therefore be distinguished from verified peak reduction. Nameplate enrollment shall be reported separately from available and delivered capacity and shall not be treated as equivalent to delivered system value. EDC filings and annual reports to the Board shall reconcile enrollment, commitments, payments, attrition, event performance, and any waitlist as required by the MFR. Staff recommends that any expansion beyond these initial quantities be assessed by Staff and notes that should a recommendation for expansion be made it would require affirmative Board review and action.

## 5. Dispatch Events -

**Summary of Comments:** Stakeholders addressed event duration and frequency, advance-notice requirements, emergency events, the purposes for which resources should be dispatched, and the respective roles of the Board and EDCs in defining and calling events.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G; JCP&L; RECO; NJNG

The EDCs emphasized preserving operational flexibility in the design of Dispatch Events. PSE&G recommended allowing EDCs to propose the maximum number, duration, notice, and other event parameters based on changing grid and market conditions. RECO supported the proposed four-hour event duration but recommended avoiding prescribed dispatch windows or seasonal event limits so EDCs can respond to prolonged extreme temperatures and reliability conditions. JCP&L similarly recommended that any annual or seasonal cap provide exceptions or separate treatment for EDC-initiated reliability, resiliency, and distribution-system events.

Regarding notification, ACE recommended consistent statewide rules that permit EDCs to shorten notice during reliability or emergency conditions. RECO recommended sufficient advance notice for scheduled events and shorter notice for system emergencies, emphasizing the need to manage battery state of charge during sustained, consecutive-day events. JCP&L recommended evaluating whether participating technologies, communications systems, and aggregators can reliably respond within the

proposed ten-minute emergency-notice period. NJNG emphasized the potential need for longer-duration and consecutive-day performance, citing July 2026 PJM emergency and pre-emergency conditions lasting up to eight hours and totaling more than thirteen hours across two days. NJNG also recommended evaluating resource availability, dispatch performance, customer outcomes, pre- and post-event load, recharge timing, rebound effects, and secondary peaks during sustained grid-stress conditions.

ACE, JCP&L, and RECO supported a Board role in establishing program objectives, general guidelines, and dispatch priorities, together with EDC authority over event activation and operational decisions. The utilities identified system-peak reduction, localized distribution constraints, reliability, resiliency, and improved grid utilization as appropriate Dispatch Event purposes. ACE and JCP&L recommended formal dispatch hierarchies prioritizing distribution-system reliability needs over conflicting VPP, wholesale-market, aggregator, or customer signals. PSE&G recommended giving EDCs the primary role in defining event types and maximum duration, subject to Board review and approval, as well as priority to dispatch, curtail, or prevent resource dispatch when necessary for distribution-system reliability. NJNG recommended that Block 1 be implemented with clear dispatch and performance rules and that utility responsibilities be clearly defined for dispatch communications, performance measurement, incentive administration, and cost recovery.

**ii. DRC**

DRC recommended that the Board establish uniform minimum categories, purposes, and measurement rules for Dispatch Events so that the four EDC programs are comparable and their ratepayer value can be independently evaluated. Its proposed statewide framework would address PJM capacity and transmission peak events, distribution thermal constraints, local congestion, emergency events, event-duration limits, notice requirements, baseline or state-of-charge requirements, and rules governing overlapping events. DRC emphasized that a kW of performance should have a consistent meaning across EDC territories and that event definitions should not make performance materially easier or harder to satisfy in one territory than another.

As part of a broader sensitivity analysis, DRC recommended that the BCA test dispatch success, event duration and frequency, and EDC forecast accuracy, together with other cost, market, technology, and participation assumptions. These sensitivity cases would allow the Board to evaluate whether program benefits continue to exceed costs under reasonable variations in Dispatch Event performance and operating conditions.

Within Board-established parameters, DRC supported allowing EDCs to call Dispatch Events based on local system conditions, provided that the reason for each event is documented and reported. For distribution events, it recommended linking each dispatch to an identified constraint and reporting whether the event changed system loading sufficiently to support an avoided or deferred distribution investment.

DRC also recommended event-level reporting identifying the reason for each event and targeted system need, enrolled and available kW, dispatched and delivered kW, event duration, Performance Factor, forecast accuracy, customer opt-outs, and estimated capacity, transmission, or distribution value. Together, these recommendations seek to make dispatch performance consistent, auditable, tied to identified system needs, and capable of demonstrating verified ratepayer benefits.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; EnergyHub; Koolbridge Energy; Lunar Energy; Mainstay Energy; PowerFlex; Prologis; RExChain; Solar Landscape; Uplight; Voltus; WeaveGrid; Xura; BTM Coalition (Tesla) – Dominic Gatti

Commenters proposed different approaches to Dispatch Event frequency and duration. The BTM Coalition recommended approximately sixty (60) standard events annually, together with a minimum annual-event requirement and authority to call emergency events above the standard cap. Dominic Gatti similarly supported increasing the annual limit above thirty-five (35). Uplight recommended varying event frequency and duration according to the grid service being provided rather than establishing a rigid statewide cap. Koolbridge supported the proposed seasonal and annual event structure and four-hour maximum, together with a bounded number of readiness tests outside the annual count and distinct treatment of system-peak, distribution-constraint, and reliability events. Xura recommended a three- to four-hour maximum and advance establishment of annual limits, seasonal windows, and related parameters. RExChain recommended fixing event duration in advance or permitting participants to elect a capacity-and-duration commitment, reasoning that variable duration affects financing and effective compensation.

Commenters generally recommended greater notice for routine events. The BTM Coalition recommended twenty-four (24) hours for standard events and approximately fifteen (15) minutes for emergencies, while EnergyHub recommended twelve (12) to twenty-four (24) hours for routine

events. PowerFlex and Uplight supported day-ahead notice where practicable. Voltus maintained that two (2) hours may be insufficient to recharge a battery for a four-hour event and recommended either extending the notice period or accounting for the resource's state of charge when notice is issued. RExChain supported the proposed two-hour and ten-minute standards but recommended limiting emergency events to a defined share of the annual total and prohibiting dispatch during an active severe-weather warning or declared emergency in the affected territory. The BTM Coalition recommended treating emergency events consistently with the proposed performance exemptions, while Mainstay Energy emphasized clearly defined emergency opt-outs and protection of customer-selected critical-load reserves.

Several commenters supported establishing statewide Dispatch Event purposes while allowing EDCs to determine when and where qualifying system conditions occur. EnergyHub, Prologis, and Solar Landscape recommended Board-defined statewide outcomes or event categories, with EDCs establishing system-specific timing, location, and operational triggers. Uplight recommended a limited, outcomes-focused Board role, while PowerFlex recommended that the Board ensure event designs advance transparent and implementable peak-reduction and affordability objectives. RExChain proposed a more prescriptive statewide framework under which the Board would establish binding permissible event categories and EDCs could propose only incremental distribution-specific events. RExChain also recommended a signal-and-settle structure in which EDCs issue standardized dispatch instructions, participants bear responsibility for delivery, and direct EDC control is reserved for bona fide reliability emergencies subject to subsequent reporting. WeaveGrid emphasized time- and location-specific distribution constraints, while Solar Landscape identified capacity and transmission peaks, local congestion, reliability emergencies, and distribution-investment deferrals as measurable event purposes.

Commenters differed regarding PJM 5CP targeting. Lunar Energy recommended making best efforts to dispatch during each of PJM's five coincident peaks. The BTM Coalition maintained that targeting 5CP or negative Peak Load Contribution values would primarily reallocate capacity costs rather than reduce an EDC's zonal capacity obligation and recommended aligning capacity dispatch with a Peak-Shaving Adjustment Plan or comparable load-forecast mechanism. Voltus similarly recommended focusing Block 1 on distribution and non-emergency transmission value not already compensated through PJM. These positions reflect differing views regarding whether Dispatch Events should principally

target existing PJM peak-allocation constructs or broader incremental system and distribution value.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties ("JCEP"); MSSIA; New Jersey Clean Capacity Coalition; New Jersey Clean Energy Ventures; Vote Solar; Solar Energy Industries Association – Georgina Arreola-Lennox; Solar Energy Industries Association – Joan White; Advanced Energy United – Chloe Holden; ChargEVC-NJ – Pamela Frank

Several trade associations supported increasing event frequency. Advanced Energy United recommended permitting sixty (60) to ninety (90) events annually, with a minimum of twenty (20), and JCEP recommended approximately sixty (60) standard events and allowing emergency events above the routine cap. Similarly, Vote Solar recommended at least sixty (60) summer events while suggesting that the Board consider twenty (20) winter events and as many as ninety (90) total events. Joan White similarly recommended more than sixty (60) annual events, while Pamela Frank recommended maximizing event frequency and Georgina Arreola-Lennox supported both additional events and greater notice. Chloe Holden connected a higher event obligation to the need for increased compensation. New Jersey Clean Energy Ventures instead focused on duration, recommending a three (3) hour maximum because some residential batteries may be unable to sustain nameplate output for four (4) hours, particularly as the batteries degrade.

Advanced Energy United and JCEP recommended twenty-four (24) hours' notice for standard events, while Joan White requested more than the proposed two (2) hours. Advanced Energy United supported as little as fifteen (15) minutes' notice for emergency events and recommended that nonparticipation in an emergency event called with less than twenty-four (24) hours' notice not count against the customer in the performance calculation, while customers that respond should receive compensation. JCEP recommended day-ahead notice for routine events, retaining shorter notice for genuine emergencies, and treating emergency events as exemptions so unavailable systems are not penalized. New Jersey Clean Energy Ventures similarly recommended sufficient preparation time and narrowly defining the circumstances qualifying for emergency treatment. Clean Peak Energy Group recommended a simplified day-ahead protocol for the initial 2027 summer season if full EDC communications systems are not yet available.

The applicable associations generally supported statewide Board-defined purposes and operating parameters, combined with EDC discretion over individual calls. JCEP recommended statewide rules governing event purposes, duration, frequency, notice, charging, customer reserves, consecutive events, and other operational requirements. New Jersey Clean Energy Ventures supported the Board's development of a common statewide framework governing the purpose and operating parameters of dispatch events, but called for the EDC to maintain discretion to determine individual events. Vote Solar recommended that the MFR Order identify the grid services each EDC must incorporate, with exclusions requiring Board approval. MSSIA favored a leading Board role because dispatch requires balancing distribution, transmission, public-policy, recharge, and investor considerations. The New Jersey Clean Capacity Coalition recommended a statewide taxonomy distinguishing event-based generation, transmission, and distribution services from continuously settled value streams such as energy arbitrage, while allowing EDCs to set specific call windows and seasonal parameters.

The associations also differed regarding the appropriate peak-reduction construct. MSSIA recommended including zonal transmission peaks, Clean Peak Energy Group emphasized actual coincident-peak performance, and New Jersey Clean Energy Ventures included PJM capacity and transmission peaks, distribution constraints, congestion, and reliability emergencies. Advanced Energy United recommended weather- and reliability-driven events and a Peak-Shaving Adjustment Plan or comparable load-forecast mechanism, while JCEP cautioned that 5CP targeting alone may shift zonal capacity-cost allocation rather than reduce the underlying obligation. These comments generally support broader, clearly defined grid-value objectives rather than treating all Dispatch Events as interchangeable.

**v. Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft; New Jersey Environmental Justice Alliance ("NJEJA")

Cammie Croft recommended that the Board establish event categories and binding outer limits on notice, duration, annual frequency, and test calls, while leaving individual dispatch decisions to the EDCs. She emphasized that participants need to know the operating obligations at the time of a ten-year award and recommended capping test calls, requiring additional calls either to count toward the annual limit or receive additional compensation, and keeping any additional dispatch opportunities within the Board-established operating envelope. She also supported a bounded and

reported emergency override while otherwise relying on dispatch signals executed by participants or aggregators.

NJEJA recommended giving a Community Advisory Board veto authority over dispatch-priority rankings for emergency events during extreme-weather conditions, thereby incorporating community representation into decisions affecting how storage resources are prioritized during emergencies.

**vi. Program implementers, consultants, and academic commenters**

Commenter(s) Referenced in This Summary: Base Power; Michael Winka; Peter Fried; Solar United Neighbors; Individual – Stanislav Jaracz

Solar United Neighbors recommended approximately sixty (60) to 100 annual events and at least twenty-four (24) hour notice so participating resources can be fully charged and prepared. It further recommended that poor performance during events called with less than twenty-four (24) hours notice not reduce participant compensation. The other commenters in this category did not recommend a specific statewide event count or duration.

Michael Winka supported using Block 1 and the interim VPP period to test dispatch for services beyond coincident-peak reduction through a sandbox process developed by the Board, EDCs, and stakeholders. He envisioned the Board helping define and test additional services during the interim stage, while ultimately acting as the regulator rather than directly defining market operations in a mature DSO/VPP framework. Base Power recommended using a common near-term event calendar where an event may simultaneously provide capacity, transmission, and distribution value, with longer-term consideration of separately defined and compensated event categories. They also supported fleet-level dispatch signals rather than direct utility control of individual devices.

Peter Fried recommended that participating municipal electric utilities and the cooperative possess independent authority to define and control call hours for resources connected to their systems, rather than placing those resources under investor-owned EDC dispatch authority. Stanislav Jaracz raised a customer-resilience question concerning how the program would treat a battery that cannot perform during a Dispatch Event because a power outage is occurring, identifying the need to clarify the interaction between event obligations, outages, and performance treatment.

**Board Staff Response:**

Staff recommends statewide Block 1 parameters of a three-hour maximum event duration, at least 21 hours' advance notice, and no more than 35 Dispatch Events per year, including up to 25 summer events and up to five winter events. These parameters balance the EDCs' requests for operational flexibility with the requests of technology providers, trade associations, and other market participants for predictable event obligations and sufficient notice, as well as environmental and consumer commenters' emphasis on firm outer limits and customer protections. The three-hour limit recognizes the limited duration of the residential and small-commercial batteries expected to enroll in Block 1 and reduces the risk that otherwise capable resources receive little or no compensation because they cannot sustain output through a longer event. It also reflects the fact that further research by Staff indicated that the longer event durations provided only a very small increase to the chance that dispatched storage would reduce actual peaks, which is already quite high with a three-hour event duration. Staff therefore concluded that Block 1 would provide greater peak reduction value if the discharge from relatively energy-limited BTM energy storage devices was concentrated into three rather than four hours. The summer-weighted allocation reflects the program's primary capacity and transmission objectives, including performance during PJM coincident-peak periods, while the winter limit responds to concerns raised by storage-market commenters regarding shorter charging windows and consecutive-day recharge constraints for solar-plus-storage systems.

Staff acknowledges commenter concerns about whether Block 1 should target PJM 5 CPs, and commenter's point that 5 CP data at present is primarily used for intrazonal capacity cost allocation and does not directly determine a zone's overall capacity obligation. Nonetheless, Staff maintains its recommendation to target the 5 CPs in addition to 1 CP periods (which despite the CP label are technically non-coincident peaks). The reason for this is that PJM's BTM storage load forecast adjustment mechanism is still in its infancy. PJM has informed Staff that at present it is primarily based on the nameplate capacity of deployed systems rather than the actual peak reduction they provide. However, PJM indicated that within the next few years it will likely adjust its BTM storage load forecast adjustment to explicitly account for actual peak reduction once BTM storage deployment becomes material. As it is unclear whether PJM's revised load forecast adjustment mechanism will be based on coincident or noncoincident peaks, Staff recommends that Block 1 target both 5 CP as well as 1 CP periods to future proof the program. Staff also notes that historically 5 CP and 1 CP periods occur very close together, often in back-to-back

hours, which indicates that Block 1's three-hour dispatch events can effectively target both without much difficulty.

The 21-hour notice requirement similarly provides participants and their operators a reasonable opportunity to manage state of charge, customer backup reserves, and charging schedules without eliminating the EDCs' ability to forecast and target likely peak periods. Staff does not adopt requests for materially more frequent events because increasing the obligation without corresponding operational experience could increase degradation, customer attrition, and program costs before Staff can determine whether the additional calls produce incremental ratepayer value. However, as described in the Order and MFRs EDCs may request and describe in their filings an alternative dispatch logic if such an arrangement can be demonstrated to provide greater ratepayer savings.

Staff does not recommend a separate short-notice emergency-event construct for Block 1. The record demonstrates that the expected battery fleet requires adequate notice to manage state of charge and preserve customer-selected backup capability, and Block 1 compensation is designed around planned, measurable performance rather than emergency availability. This decision does not prevent an EDC from using Block 1 resources to address qualifying grid-stress or distribution conditions within the statewide parameters. Each EDC will retain authority to identify grid needs and call individual events, but its filing must describe event purposes, forecasting methods, resource selection, treatment of overlapping calls, customer opt-outs, measurement, and reporting. These requirements respond to DRC's concern that EDC discretion not produce materially different or unauditable performance obligations: a kW of performance will be measured under the same statewide event and settlement rules, while event-level reporting will allow Staff to determine why an event was called, what resources were available, what they delivered, and what system objective the event served.

Staff also considered comments recommending a Peak Shaving Adjustment Plan or alternative dispatch logic. Staff agrees that Block 1 performance must be reflected in the mechanism that determines New Jersey's zonal load forecast for the program to produce the projected capacity savings. Current PJM rules, however, create barriers to placing BTM storage directly into EDC Peak Shaving Adjustment Plans absent changes to PJM's governing documents. The Order therefore uses the existing state-program information pathway under which Board Staff provides PJM with projected and actual storage deployment data for incorporation into PJM's load forecast, and

requires EDCs to provide the enrollment, interconnection, operational, and performance information needed for that submission. This is a reasonable near-term mechanism because it connects verified program deployment to the load forecast without delaying Block 1 pending a PJM tariff change. An EDC may propose different dispatch logic if it demonstrates greater measurable ratepayer savings while preserving customer protections and consistent performance accounting; any change to the statewide event limits requires express Board action.

Regarding DRC's recommendation to explore how sensitive the Block 1 BCR is to assumptions about the Block 1 program's effectiveness at targeting PJM's peaks, Staff notes that this can be easily determined from the data presented in Attachments G and H. Specifically, both capacity and transmission savings linearly scale with the CP Reduction Effectiveness value, which is assumed to be 95% in the presented scenarios. Avoided capacity and transmission costs are the only benefits in Scenario 3, what the BCR values would be with different CP Reduction Effectiveness values can be easily calculated by multiplying the shown BCR values by the preferred CP Reduction Effectiveness value divided by 95%. For example, if one holds all other assumptions in Scenario 3 equal and assumes Block 1's CP Reduction Effectiveness value will only be 80%, then the statewide lifetime program BCR would be 80% divided by 95% multiplied by 1.76, or approximately 1.48.

## 6. NEM

**Summary of Comments:** - Stakeholders addressed the eligibility of NEM customers and whether existing EDC tariffs, operating requirements, export rules, or procedures could impede their participation in GSESP.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G

PSE&G identified current NEM rules and the absence of a generally available tariff for battery exports, other than for larger Qualifying Facilities, as potential constraints on customer ability to realize the full value of participating batteries. It did not recommend a definitive NEM eligibility rule but indicated that clarification of the treatment and compensation of battery exports is needed.

ACE recommended aligning the export-limited interconnection requirements under N.J.A.C. 14:8-5.2(l) across GSESP and other DER programs. It explained that, because Block 1 contemplates studying

storage systems based on their configured export limits rather than nameplate capacity, the Board should establish a statewide process for certifying and verifying export-limiting devices. ACE further recommended requiring aggregators and OEMs to document compliance with approved export-limit specifications and report configuration or firmware changes that could affect export behavior. ACE stated that these measures would support consistent interconnection studies, reliable dispatch performance, and the transition of participating resources into future VPP and GridFlex programs.

**ii. DRC**

DRC made recommendations concerning device-level measurement, verification of charging and discharging, and the use of existing AMI, manufacturer, aggregator, and EDC capabilities in response to the broader metering and dispatch architecture, but did not substantively address the issue of NEM in their comment.

**i. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; Lunar Energy; RExChain; BTM Coalition (Sunrun) – Thad Culley; Trinity Solar – Kenneth Ebbert

The BTM Coalition and Thad Culley supported allowing net-metered solar-plus-storage systems to export battery energy during GSESP Dispatch Events. The BTM Coalition recommended clarifying that solar-paired storage is eligible to export under NEM where appropriate controls ensure that the battery charges from onsite solar. Lunar Energy requested clarification of how dispatched battery exports would interact with NEM and export-limiting requirements and recommended wholesale accounting reforms that would recognize exports beyond onsite load. RExChain separately requested clarification regarding whether battery exports during Dispatch Events would be permitted, required, or excluded and how those exports would settle against the customer's NEM arrangement. RExChain also requested confirmation that Block 1 dispatch and device-level measurement would not affect the paired solar system's PJM GATS reporting or eligibility to generate Renewable Energy Certificates.

The BTM Coalition identified existing EDC interconnection materials as a practical barrier because they may cause batteries to be installed in non-export configurations before GSESP export requirements are finalized. It recommended that the MFRs clarify export authorization and require EDC interconnection applications to allow applicants to identify intended exports

under GSESP and future grid-services programs. In written questions submitted in advance of the stakeholder call, Kenneth Ebbert asked how onsite solar production, contemporaneous battery charging, and battery exports would be measured during Dispatch Events and whether participating customers would retain applicable NEM credits and other bill savings.

**iii. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Joint Clean Energy Parties; Vote Solar

The Joint Clean Energy Parties and Vote Solar supported allowing existing NEM customers to add storage, participate in GSESP, and export during Dispatch Events without losing the NEM treatment applicable to the underlying solar system. JCEP maintained that participation in NEM and GSESP compensates distinct services and recommended express program language protecting NEM eligibility while appropriately distinguishing the associated value streams.

Advanced Energy United recommended that the MFR Order clarify that participating storage projects may export to the grid and require each EDC filing to identify any tariff, documentation, or process changes necessary to enable those exports. The Joint Clean Energy Parties separately recommended that the MFR Order expressly authorize Block 1 battery exports, subject to applicable safety and interconnection requirements; direct each EDC to implement necessary interconnection-process changes; and protect the NEM status of an underlying solar system when a customer adds storage and participates in GSESP. Vote Solar recommended requiring EDCs to permit NEM customers to receive performance compensation under GSESP and VPP programs without battery exports disqualifying the customer's solar exports from NEM treatment; it also recommended accommodating non-exporting batteries in grid-flexibility programs.

**iv. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: None

The environmental, consumer, and environmental justice commenters did not substantively address whether NEM customers should be eligible to participate in GSESP or identify existing EDC NEM rules and procedures as barriers to participation.

**v. Program implementers, consultants, and academic commenters**

Commenter(s) Referenced in This Summary: Base Power; Ecological Systems LLC

Base Power recommended separating retail NEM treatment from interconnection eligibility and wholesale accounting. It proposed calculating Peak Load Contribution and Network Service Peak Load Contribution values from AMI interval data without a zero floor, thereby recognizing authorized battery exports when allocating capacity and transmission obligations, and incorporating verified Block 1 reductions into PJM load forecasts through a Peak Shaving Adjustment Plan or successor mechanism. Base Power also proposed allowing an eligible third-party supplier that separately realizes capacity and transmission value to receive a reduced, distribution-only Block 1 incentive, thereby compensating distinct distribution-system services without duplicating wholesale compensation.

Ecological Systems LLC proposed a broader Clean Peaker Parity Tariff incorporating bidirectional real-time net metering. Under its proposal, customer-owned batteries would receive market-based compensation for energy exported to the distribution system and separate compensation for absorbing energy under qualifying grid conditions. These proposals would expand the compensation framework beyond conventional NEM rather than specifically addressing whether existing NEM customers should be eligible for Block 1.

**Board Staff Response:**

Staff acknowledges the comments concerning net energy metering and the need for clarification on export capabilities for standalone and paired solar plus storage facilities. On the basis of these comments, Staff recommends that NEM customers with solar-plus-storage systems be eligible for Block 1. Staff further recommends that such customers receive full NEM credit for all their exports if the storage component of their system is configured to operate in a “NEM integrity” mode that ensures all energy the storage component exports was originally sourced from on-site solar generation. Staff further recommends that the Board require EDCs to allow both standalone storage and the storage components of solar-plus-storage systems to export power to the grid, under the terms and conditions and using the processes described in the body of the main order.

These recommendations respond to technology provider, other market participants, and solar and storage trade association comments that supported allowing solar-plus-storage customers to participate and export during Dispatch Events without forfeiting NEM treatment for

eligible solar generation, while also addressing the EDCs' requests for clear export authorization, interconnection, metering, and verification rules. Excluding solar-plus-storage customers would unnecessarily remove a substantial class of otherwise eligible batteries even though NEM and Block 1 compensate different functions: NEM compensates eligible exports from the customer-generator, while Block 1 compensates verified discharge performance during EDC Dispatch Events. Allowing both does not, by itself, constitute duplicate compensation. The relevant safeguard is to define which exports remain eligible for NEM and to measure Block 1 performance separately at the device level, consistent with DRC's broader emphasis on device-level measurement and verification. Accordingly, standalone storage and solar-plus-storage systems may seek authorization to export under N.J.A.C. 14:8-5, and a solar-plus-storage system may receive NEM credit for battery exports where equipment controls or operating software ensure that exported battery energy was charged from the paired solar facility. This approach permits participation without paying NEM credit for grid-charged energy or compromising the integrity of the underlying NEM program while also not jeopardizing the ability for solar to generate GATS compliant RECs.

Staff recommends the Board require EDCs to permit both existing and new standalone storage and solar-plus-storage systems seek authority to export by submitting interconnections requests that the EDCs process pursuant to N.J.A.C. 14:8-5. This directly addresses the implementation barrier identified by commenters: a resource installed under an unnecessarily restrictive interconnection configuration may be unable to deliver the performance for which Block 1 pays. In response to Base Power's concern regarding systems serving third-party supplier customers, Staff recommends that the applicability of the storage interconnection procedures not depend on a customer's choice of electric supplier, NEM status, or eligibility for Block 1 incentives. BTM storage seeking export authorization should be evaluated under the applicable interconnection rules at its proposed export capability, including an agreed limited-export level where applicable, regardless of program enrollment. Staff further recommends that the EDC filings identify how standardized procedures, applicable review timelines, and the prohibition on extraneous studies outside those specified in N.J.A.C. 14:8-5 will apply to these resources.

At the same time, the Order does not create a separate export-compensation rate for standalone storage. A participating standalone battery remains eligible for the applicable Block 1 performance payment, subject to program requirements. These requirements provide a uniform eligibility rule, preserve NEM integrity, avoid

duplicative compensation, and prevent unresolved export-rate questions from delaying the initial block.

Staff separately acknowledges Base Power's request that exports from interconnected behind-the-meter storage be recognized through negative PLC values, without conditioning such treatment on NEM eligibility. That request concerns the allocation and calculation of capacity and transmission obligations, rather than the establishment of a retail energy export rate and is not resolved by the NEM treatment described above. Staff recommends that each EDC submit a filing to identify the existing treatment of storage exports in PLC calculations, any applicable zero floor, the tariff, metering, settlement, and PJM coordination changes that would be necessary to implement Base Power's proposal. Each filing should also explain how verified Block 1 reductions and exports are reflected in applicable Peak Shaving Adjustment submissions or successor load-forecast mechanisms. Staff does not recommend adopting a negative-PLC methodology in this Order; instead, Staff recommends reserving that determination pending review of those filings and the applicable tariff and wholesale-market requirements. That reservation should not be construed as a requirement that otherwise authorized storage exports qualify for NEM.

# 7. Benefit Cost Methodology

**Summary of Comments:** - Stakeholders addressed whether the program design can produce the anticipated capacity, transmission, and distribution benefits, how those benefits should be quantified and verified, and whether a Peak Shaving Adjustment Plan is necessary.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G; JCP&L; RECO; NJNG

The utilities generally recognized that distributed storage can reduce peak demand and potentially produce capacity, transmission, reliability, and distribution-system benefits, but several requested additional information or implementation guidance before those benefits are treated as assured. ACE found the Straw Proposal's initial benefit-cost results directionally reasonable but requested disclosure of enrollment assumptions, avoided-peak values, dispatch frequency, degradation, customer overrides, and other underlying inputs, with the methodology updated as operational data become available. JCP&L considered the design reasonably positioned to capture systemwide capacity and transmission benefits but recommended clearly defining whether the primary objective is PJM coincident-peak reduction, utility peak reduction, or localized distribution support. NJNG

supported the performance-based approach but recommended reporting dispatch performance, availability, avoided system costs, consumer participation, and emissions impacts, where applicable, to determine whether Block 1 delivers its expected value and to inform future capacity blocks.

The utilities emphasized different mechanisms for connecting Block 1 performance to peak reduction and wholesale value. PSE&G requested near-term coordination between Staff and the EDCs regarding how enrolled resources would capture PJM value and maximize peak-capacity load reductions. ACE supported peak shaving and performance-based dispatch as Block 1 objectives and separately recommended EDC coordination with PJM to ensure that DER participation in wholesale markets remains consistent with distribution-system reliability. JCP&L requested clarification of the relative roles of PJM coincident-peak reduction, utility peak reduction, and localized distribution-system objectives. Their recommendations therefore centered on defining peak-reduction objectives and coordinating operational and wholesale-value mechanisms rather than prescribing a common PSAP requirement.

The utilities also offered distinct views regarding distribution-system value. PSE&G cautioned that Block 1's limited size and lack of locational targeting may make it difficult to materially affect individual feeders and recommended using Block 1 data to develop standardized distribution-service values for future blocks. JCP&L observed that customer-driven enrollment may not place batteries where constraints or planned investments exist and recommended establishing a framework for measuring and valuing localized benefits. RECO identified reducing localized distribution constraints, improving grid utilization, and supporting reliability as appropriate dispatch outcomes and recommended allowing event definitions to evolve based on demonstrated system needs and program performance.

ACE proposed that EDCs identify local capacity and reliability needs and competitively procure targeted services from BTM battery aggregators and DER operators through arrangements comparable to Distribution Service Agreements. ACE described DER-based solutions as potential cost-effective alternatives or complements to traditional infrastructure investments. NJNG supported a performance-based residential BTM framework capable of addressing distribution constraints and recommended reporting dispatch performance, availability, avoided system costs, customer participation, and emissions impacts to evaluate realized program value and inform future capacity blocks.

**ii. DRC**

DRC characterized Staff's RIM-like BCA framework, which focuses on costs and benefits flowing through rates, as a constructive improvement over evaluating the program primarily by MW deployment. It acknowledged Staff's reported BCRs of 2.16 for all ratepayers and 1.79 for nonparticipating residential customers while recommending that the assumptions underlying those results be stress-tested before customers are committed to a ten-year incentive stream. However, it nonetheless questioned the necessity of a ratepayer-funded program to support additional energy resources, as well as the overall impact on affordability posed by such a program.

DRC recommended separately presenting gross system benefits, participant bill savings, transfers among customer groups, reductions in utility revenue requirements, and expected customer-bill savings. It also recommended a sensitivity case excluding participant incentive payments as an independent system benefit because those payments constitute a program cost incurred to procure the claimed services rather than an incremental system saving.

For transmission benefits, DRC recommended identifying the mechanism through which reduced peak contribution would lower New Jersey transmission obligations and when those reductions would affect customer charges. For capacity benefits, it recommended explaining how verified Block 1 performance would change BGS or other procurement costs and distinguishing direct load-reduction savings from broader capacity-market price effects. DRC recognized as prudent Staff's assumption that Block 1 would not produce a capacity demand-reduction-induced price effect while the capacity market remains at its price cap. It nevertheless recommended testing scenarios in which expected capacity and transmission benefits are lower, delayed, or not realized and verifying retrospectively whether forecast savings ultimately reduce wholesale obligations, revenue requirements, or customer bills.

DRC recommended that the BCA include every incremental cost necessary to acquire, interconnect, meter, communicate with, dispatch, verify, settle, and administer Block 1 resources, including but not limited to technology, telemetry, cybersecurity, M&V, financing, customer-service, regulatory, and program-transition costs. DRC recommended that costs already recovered through base rates, Triennium programs, grid-modernization proceedings, VPP budgets, AMI approvals, or other proceedings should not be charged again to Phase 2. DRC further stated that a necessary Block 1 cost should

not be omitted from the BCA merely because an EDC proposes to recover it in another docket. DRC recommended downside sensitivities addressing a number of factors, including installed costs, financing, tax credits, degradation, replacement, participation, attrition, customer pass-through, dispatch performance, event duration and frequency, EDC forecast accuracy, administrative and enabling costs, capacity and NITS values, load growth, VPP and wholesale revenues, and the percentage of enrolled resources capable of delivering distribution benefits.

DRC also recommended comparing Block 1 with reasonably available alternatives, including tariff or rate-design changes, targeted demand response, energy efficiency, managed charging, and conventional system solutions, even if the program passes a RIM-style test. It requested annual and cumulative bill-impact analyses for residential, small-commercial, large-commercial, and industrial classes, separated by participation status where applicable, together with an affordability analysis addressing less-advantaged and fixed-income households. Forecast BCRs should be followed by annual retrospective analyses comparing expected and actual enrollment, incentive and administrative costs, performance, customer pass-through, capacity and transmission savings, distribution deferrals, and bill impacts.

DRC recommended crediting distribution-level benefits only where storage addresses a documented system constraint and produces an identifiable change in an EDC capital plan. Before enrollment, it proposed identifying constrained feeders, substations, transformers, or planned investments and documenting the applicable constraint, conventional solution, project cost, required kW reduction, timing and duration of the need, forecast load growth, and minimum performance necessary to support deferral. DRC distinguished resources located on unconstrained circuits, which may contribute to statewide capacity or transmission reductions, from resources demonstrably enabling an EDC investment to be removed, reduced, or deferred.

DRC reiterated its prior storage comments that distribution benefits should be credited only where resources are located in areas with an actual constraint, the expected avoided costs are quantified, performance during the relevant periods is reliable, and the expected load reduction is incorporated into EDC distribution planning. Drawing on its prior VPP comments, DRC further recommended treating a claimed distribution benefit as realized only when an identifiable capital project is removed, reduced, or deferred and the resulting savings are reflected in the EDC's capital plan, revenue requirement, or customer bills. It also recommended that the BCA account for the probability and expected duration of a deferral,

continuing load growth, battery degradation and replacement, the respective useful lives of the battery and conventional investment, and lifecycle costs relative to alternative solutions. For Block 1, DRC proposed locational reservations, weighting or adders, minimum locational eligibility for part of the block, or targeted solicitations to increase the likelihood that resources are deployed where measurable distribution benefits can be achieved.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; Koolbridge Energy; Lunar Energy; Outlast Power; RExChain; RIC Energy; Solar Landscape; Soltage; Uplight; Voltus; WeaveGrid; CleanPeak Energy Group – Ed Levene; Base Power – Jackson Parell

Several commenters questioned whether targeting 5CP hours or reducing individual customer PLCs would, by itself, achieve the wholesale savings assumed by the program. The BTM Coalition argued that 5CP dispatch and negative PLC values primarily reallocate existing costs unless the reductions are reflected in PJM's zonal load forecast, and recommended a PSAP or equivalent load-forecast modification. Lunar Energy similarly recommended incorporating verified Block 1 performance into a PSAP or comparable mechanism so the resources reduce the EDC's zonal capacity purchase obligation. Uplight agreed that the program must demonstrate actual system-cost reductions rather than cost reallocation, but recommended allowing each EDC to select among a PSAP, qualifying PJM capacity-market participation, or another mechanism that produces measurable savings. Base Power–Jackson Parell additionally advocated negative PLC accounting to recognize exports, although other commenters distinguished that accounting treatment from the separate need to reduce the underlying zonal obligation.

Commenters also raised broader benefit-cost alignment issues. RExChain argued that the gap analysis and BCA rely on inconsistent TOU-participation assumptions and that the minimum-output Performance Factor is not aligned with the peak-hour capacity value cited in the BCA. Voltus recommended separating the generation-capacity value available through PJM from the non-emergency transmission and distribution value procured through GSESP to prevent overlapping compensation. CleanPeak Energy Group–Ed Levene recommended considering transmission and distribution deferrals, wholesale market-price suppression, Demand Reduction-Induced Price Effects ("DRIPE"), reliability, voltage support, and other measurable benefits when evaluating ratepayer impacts.

Commenters generally considered distribution benefits attainable, but emphasized that their value depends on location, timing, operational capability, and the avoided infrastructure alternative. WeaveGrid proposed identifying the relevant feeder, transformer, substation, or constrained area; estimating the traditional investment and its present value; determining the required hourly reduction; and calculating a location-specific avoided cost rather than relying on a generic statewide value. Uplight similarly recommended locational visibility and coordinated dispatch through an Edge DERMS, while Solar Landscape and Koolbridge supported defining and measuring distribution-constraint events separately from system-peak events. Outlast Power identified well-located small-commercial batteries as a means of providing local circuit value, while RIC Energy and Soltage emphasized that distribution-connected FTM projects may be better positioned to defer larger distribution investments. These FTM recommendations were directed principally toward future or parallel program structures rather than the residential Block 1 design.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties; MSSIA; New Jersey Clean Capacity Coalition; New Jersey Clean Energy Ventures; Vote Solar; Advanced Energy United – Chloe Holden

Advanced Energy United, Chloe Holden, and the Joint Clean Energy Parties argued that dispatch aligned only with 5CP hours would not necessarily reduce the zonal capacity obligation underlying ratepayer costs. Advanced Energy United recommended requiring EDC proposals to include a PSAP or equivalent load-forecast modification through which verified GSESP reductions would be incorporated into PJM forecasts. The Joint Clean Energy Parties treated a PSAP as one available pathway and recommended that each EDC explain how and when enrolled MW will be reported to PJM, while New Jersey Clean Energy Ventures likewise supported treating distributed storage as a demand-side resource or load reduction in PJM forecasts. Clean Peak Energy Group placed comparatively greater emphasis on rewarding performance during the actual intervals that determine generation-capacity and transmission obligations, illustrating a material difference regarding how wholesale value should be captured.

The trade associations recommended a broader and more transparent benefit-cost record. Collectively, Clean Peak Energy Group and the Joint Clean Energy Parties requested disclosure of the assumptions, inputs,

avoided-cost values, performance expectations, and calculations supporting the capacity, transmission, distribution, and other benefits claimed in the BCA. MSSIA recommended including demand-reduction-induced price effects, while Clean Peak Energy Group supported evaluating market-price effects, congestion, avoided losses, reliability, resilience, and other reasonably quantifiable benefits. The Joint Clean Energy Parties and New Jersey Clean Capacity Coalition recommended an independent avoided-cost or value-stack study. JCEP recommended such a study covering capacity, transmission, distribution, energy market value and wholesale price effects, ancillary services, avoided emissions, and market-price benefits. Vote Solar additionally recommended basing program capacity on deliverable output rather than nameplate capacity so the benefit calculation reflects backup reserves, efficiency losses, and other limits on actual grid delivery.

Trade associations addressing distribution-level benefits generally considered them quantifiable when linked to identified locations, system needs, and avoided investments. Clean Peak Energy Group recommended identifying constrained areas and comparing the cost of incremental storage compensation against the present value of the substation, transformer, feeder, or other investment avoided or deferred, potentially through a Locational Distribution Value Adder. Advanced Energy United recommended a locationally differentiated, long-term tariff for midscale distribution-connected FOM storage, with durable payments reflecting the avoided capacity, transmission, and distribution costs delivered by projects located on constrained feeders. Vote Solar recommended accommodating non-exporting BTM batteries in grid-flexibility rules and incentives because systems serving on-site load can still reduce upstream distribution demand. It also recommended requiring hosting-capacity maps to report both load and generation at the line-section or nodal level so stakeholders can evaluate hybrid charging and export configurations, better understand grid constraints, and support flexible interconnection for larger C&I and FOM projects. The Joint Clean Energy Parties recommended a Board-funded independent value-stack study and gap analysis for the FOM and GridFlex frameworks that distinguishes benefits capable of valuation and implementation at program launch from those requiring additional data or methodological development. The New Jersey Clean Capacity Coalition separately recommended an independent avoided-cost study to inform compensation for a future distribution-connected FOM program, including energy, capacity, transmission, distribution, avoided greenhouse-gas, and energy- and capacity-market-price benefits.

**v. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: Cammie Croft; New Jersey Environmental Justice Alliance

Cammie Croft acknowledged the Straw Proposal's finding that Block 1 could produce savings for non-participants but raised an additionality concern not resolved by the stated BCA: the analysis does not determine whether an incentivized battery would have been installed without the program. She maintained that ratepayers receive greater value when the incentive causes incremental deployment and recommended program structures that extend participation to households the existing market is unlikely to reach. She did not take a position on whether a PSAP is necessary.

The New Jersey Environmental Justice Alliance emphasized that program cost-effectiveness should translate into measurable benefits for participating customers and OBCs rather than disproportionate developer or utility value capture. It recommended binding revenue-flow requirements, including a 50% customer pass-through floor and directing 25% of total program revenues to an OBC Resilience Fund. For double-counting oversight, NJEJA proposed quarterly Equity Performance Reports separating GSESP incentive payments, capacity-market revenues, and ancillary-service compensation, together with associated clawback provisions. NJEJA also recommended coordinating GSESP with the separate PSUP proceeding by requiring PSUP filings to identify distribution feeders where GSESP storage could defer substation-transformer, feeder-reconductoring, or other traditional infrastructure upgrades. It argued that this coordination could improve cost-effectiveness through strategic siting, including recognition of the social and locational value provided by storage in high-energy-burden OBC census blocks.

**vi. Program implementers, consultants, and academic commenters**

Commenter(s) Referenced in This Summary: Base Power; Don Whitley; Ecological Systems LLC; Michael Winka; Solar United Neighbors; Syntropic Capital Partners

Base Power argued that the wholesale benefits underlying the Straw Proposal's BCA will not be fully realized unless verified reductions are incorporated into PJM load forecasts and exporting resources can receive negative PLC values. It recommended directing each EDC to include Block 1 resources in its PSAP submissions or a successor load-forecast mechanism, revising wholesale accounting to recognize exports below zero customer load, and registering and settling AMI data for both consumption and exports. Solar United Neighbors similarly maintained that

the program's success depends on EDCs being able to rely on enrolled resources during high-demand periods to reduce capacity obligations, although it focused on adequate event frequency and availability rather than specifying a PJM filing mechanism.

These commenters identified several approaches to realizing distribution-system value. Base Power recommended separating the distribution-value portion of the Block 1 incentive from its capacity and transmission components. It proposed allowing third-party suppliers that monetize capacity and transmission value through wholesale accounting to receive a distribution-only incentive, calculated as $200/kW-year multiplied by the avoided-distribution-investment share of total quantified benefits in the BCA. For the near term, Base Power proposed applying that lower rate to the same Dispatch Events and Performance Factor used for other participants. Over the longer term, it recommended considering separate designation and compensation of capacity, transmission, and distribution events, with the distribution incentive targeted to the particular times and electrical locations where storage can relieve otherwise-overloaded distribution infrastructure. Michael Winka proposed using PSUP information to establish targeted sandbox areas where locational incentives could test whether storage defers upgrades. In both his written submission and oral comment, Don Whitley asked why standardized FOM storage could not be located at or near existing EDC substations, with EDC purchasing, installation, operation, maintenance, security, and coordinated dispatch near constrained load during high demand. Ecological Systems LLC proposed a Clean Peaker Parity Tariff that would separately compensate availability, exported energy, and autonomous local grid-support or absorption services.

Syntropic Capital Partners supported transparency in the published gap and benefit-cost analyses and recommended extending that transparency to the assumptions affecting performance and ownership structures. More broadly, these commenters viewed Block 1 as an opportunity to test whether distributed resources can provide lower-cost local services, but their recommendations ranged from modifying the existing BCA and PJM accounting framework to testing locational service models or replacing the contemplated compensation structure with an alternative tariff.

**Board Staff Response:**

Staff recommends using the modified RIM test as the primary BCA because Block 1 is principally intended to reduce costs borne by ratepayers through avoided energy, capacity, transmission, and to a lesser extent distribution costs. The remaining five tests provide

supplementary perspectives on participant, program-administrator, resource, and societal effects. Attachments G and H detail the relevant assumptions and provide the results of Staff's preliminary RIM tests. This framework and additional information responds to the EDCs' requests for clearer assumptions and implementation pathways, the requests of technology providers, other market participants, and trade associations to connect verified performance to PJM load forecasting and disclose the underlying BCA inputs, and environmental and consumer commenters' focus on additionality and verifiable customer benefits. The directive to the EDCs to perform more detailed BCAs based on this framework also addresses DRC's concern that the claimed benefits must be evaluated using full-cost accounting and retrospective verification. Each EDC must perform all six analyses required by the MFRs, or provide a supported explanation where a test does not apply, using the common benefit and cost categories prescribed for Block 1. The EDC must include every incremental cost necessary to administer and deliver the program—including incentives, administration, technology, telemetry, cybersecurity, interconnection support, EM&V, customer support, reporting, and any proposed capital or deferred costs—and demonstrate that the same cost is not already recovered through base rates, Triennium programs, VPP budgets, AMI approvals, grid-modernization proceedings, or another mechanism. Requiring full program costs while prohibiting duplicate recovery addresses DRC's concern that favorable BCR results should not depend on omitting costs or shifting them to another docket.

Staff also notes the myriad requests and recommendations for additional studies and sensitivity analyses from DRC and other commenters. In light of these requests, Staff has provided two additional scenarios that explore how the BCA changes if New Jersey capacity prices fall to $100 per MW-day (well below their historic average) and if no distribution benefits are realized from Block 1. The low capacity price scenario also incorporates the DRIPE impacts that would be expected in a scenario where the current capacity price cap is no longer expected to bind, addressing MSSIA's request that DRIPE impacts be explicitly modeled. Notably, even the limited DRIPE impacts that would be expected with a $100 per MW-day capacity price (which corresponds to the PJM capacity market clearer in the lower-sloped and thus more price-inelastic part of the Variable Resource Requirement curve), DRIPE impacts almost completely cancel out savings from lower capacity prices. This indicates that compared to nearly any average capacity price scenario between $100 per MW-day and the $325 per MW-day (which is assumed to be a capped price in where there is no DRIPE), Staff's base case conservatively

underestimates capacity savings, potentially by a significant amount. Staff's base case would likewise underestimate capacity savings if the current price cap is not extended to future capacity auctions and the market starts clearing at the "normal" maximum price, which based on recent capacity market auction parameters are likely to be well over $500 per MW-day. The no distribution benefit sensitivity also shows that the all-ratepayer lifetime BCR for the program remains well above 1.0, even with Staff's conservative capacity savings assumptions.

Staff acknowledges that these two additional sensitivity cases do not fully answer every request for numerous other sensitivities and analyses that could be run. However, Staff believes they are sufficient to show that Staff's finding that the program's BCR is well above one is likely robust to a wide range of reasonable assumptions. Furthermore, Staff is concerned that the fulfilling every request for additional analysis risks analysis paralysis and material delays to the launch of the Block 1 program. Considering the current critical shortage of capacity in PJM at present and the fact that Block 1 provides a robust BCR even when considering *only* avoided capacity and transmission costs, this is a situation in which speed to launch and thus speed to power has significant ratepayer benefit. Staff therefore declines to make the perfect the enemy of the good by analyzing every conceivable scenario before proceeding with Block 1, especially since the EDCs are themselves being directed to provide their own independent and more detailed BCAs before the Board approves final program designs.

For similar reasons, Staff declines to recommend including many of the tweaks related to ensuring greater distribution system value or OBC benefits in the Block 1 design. While Staff believes these recommendations have merit and are well worth considering in future Blocks, Block 1 is intentionally designed to be comparatively simple and primarily target bulk system savings that accrue to all ratepayers while providing data that can inform the design of more sophisticated future blocks. Simplicity is especially valuable given those objectives, because it enables faster launch, enrollment, and deployment, thereby providing ratepayer savings and data more quickly.

Staff also believes the BCA results and supporting data and assumptions in Attachments G and H, along with the discussion in these comment responses, addresses DRC's concerns about the affordability impacts of the program. In short, the BCA results and the additional discussion in these comment responses show that the Block 1 program is likely to provide significant cost savings and thus *reduce* retail electricity costs over its lifetime. Staff acknowledges that the delay between when program costs are incurred and benefits are

realized means that costs may exceed benefits for the first two years of the program. However, this also corresponds to the ramp-up stage of the program in which cumulative program costs are expected to be only $30 million across the entire state (as shown in Table 4 in the main Order, the cumulative sum of projected EDC Block 1 budgets for 2027 to 2029 is $30 million). Staff is also actively investigating the possibility of using the Orsted settlement money deposited in the Energy Storage Fund to cover Block 1 program expenses during the initial period in which Block 1 does not produce sufficient offsetting savings to cover program costs. If this approach proves to be viable, it should prevent Block 1 from ever resulting in bill increases for ratepayers.

Staff also disagrees with DRC that the need for a program like Block 1 has not been adequately demonstrated. First, the current critical capacity shortage in PJM, widely acknowledged problems with the PJM capacity market, and New Jersey's status as a capacity importing state all point to an urgent need for more in-state capacity that comes online quickly. BTM energy storage is a potentially significant source of capacity that meets that criteria. Second, it is a resource type that can act as a demand-side load reducer that can reduce the total amount of capacity New Jersey ratepayers have to buy from the PJM capacity market. Unlike supply-side resources, this allows BTM energy storage to reduce costs, even if the market is clearing at a capped price and/or too far short of PJM's reliability requirement for an incremental unit of supply to lower capacity prices. Third, Staff notes that N.J.S.A. 48:3-87.8(d) requires the Board to support the deployment of 2,000 MW of storage within the state by 2030. It has been eight years since that statutory provision was enacted and only a little more than four years remain before the deadline, and it is clear that the rate of energy storage deployment in the state without incentives has been insufficient to have reasonable confidence the target will be met in the absence of programs like Block 1.

Staff also recognizes the numerous requests for an explanation of how Staff envisions Block 1 will reduce zonal capacity obligations, given commenters' point that this is not something that reducing measured load during 5 CP periods accomplishes by itself. In short, Staff recommends the Board utilize PJM's load forecast adjustment mechanism for BTM energy storage by annually providing PJM with data on Block 1 resource deployment and performance, both actual and projected. For context, in the past few years PJM has begun annually soliciting data about state BTM solar and storage programs from all state utility commissions, including the Board, in its footprint. If a state utility commission provides the necessary data by late July, PJM then feeds that state-provided data into a BTM solar and storage

deployment forecast prepared by S&P Global, which PJM in turn uses to develop a downward load forecast adjustment to its annual load forecast with zonal level granularity. These adjustments are currently reported by zone in Table B-8b of the annual load forecast PJM releases in January. Pursuant to Schedule 8 of PJM's Reliability Assurance Agreement, those zonal load forecasts, which include the downward adjustments from BTM storage, are then used to determine the final zonal capacity obligations for the delivery year that starts in that same calendar year. This means that Block 1 data the Board provides PJM within July of a given year can reduce the zonal capacity obligations for the delivery year that starts on June 1 of the subsequent calendar year. That is a notably shorter timeline to the realization of capacity savings than supply-side market participation could provide due to the three-year forward design of the PJM capacity market.

As to why Staff favors this approach over using PJM's PSA mechanism, and why Staff continues to recommend that Block 1 target dispatch to 5 CP in addition to 1 CP periods, please see Staff's response to comments in the Dispatch Event section.

Staff also notes that Staff provided preliminary information about Block 1 to PJM in July of this year, which already appears to have resulted in a substantial increase to the S&P Global's New Jersey BTM storage deployment forecast. Indeed, if PJM accepts S&P Global's deployment forecast without material changes, it is quite possible that Block 1 will start providing capacity savings more quickly than Staff's BCA assumes. This is because S&P Global's forecast shows a significant uptick in New Jersey BTM storage deployment beginning in 2027, presumably due to the Block 1 Program. It is thus possible that the Block 1 program may reduce New Jersey zonal capacity obligations as soon as 2027. In contrast, for Block 1 BCA purposes Staff made the intentionally conservative assumption that the first load forecast in which PJM would account for Block 1 capacity is the 2029 annual load forecast that will determine zonal capacity obligations for the 2029/2030 delivery year.

Thus, avoided capacity cost savings are expected to result from reduced zonal load reflected in PJM's load forecast leading to reduced peak share-driven allocation of capacity costs to the participating EDCs. These wholesale savings, in turn, will reduce suppliers' expected cost to provide BGS supply, reducing competitively-awarded BGS prices. Because BGS-RSCP supply is procured through three annual tranches, the associated savings would phase in with each tranche, as we assume that suppliers will only factor savings for projects that are online at the time of the BGS procurement:

approximately 33 percent in the first applicable Delivery Year, 67 percent in the second, and 100 percent thereafter. In the near term, PJM's recognition of projected BTM storage deployment through annual state regulatory submissions should reduce forecast zonal peak load and the corresponding capacity procured through BGS. Assuming the program becomes operational in 2027, these reductions are expected to be reflected by the 2029/2030 Delivery Year. See Appendix G for further methodological detail.

Furthermore, this demand-side approach to reducing capacity costs is also the primary reason Block 1 resources are prohibited from participating in PJM wholesale markets. BTM energy storage resources that participate in PJM wholesale markets as supply side resources (e.g., through a FERC Order 2222 Distributed Energy Resource Aggregation) have their load reconstituted in PJM load forecasts to prevent double counting the same resource on the demand and supply side. Thus, BTM energy storage systems acting as supply-side resources cannot lower zonal capacity obligations and instead can only provide capacity cost relief to other ratepayers by lowering wholesale capacity prices. However, the PJM capacity market has recently begun to clear in critical shortage conditions quantities where the Variable Resource Require curve would be flat even in the absence of the present temporary price cap. This means an incremental unit of capacity supply can do nothing to lower the overall capacity clearing price. Staff expects these conditions will likely persist for at least the next two auctions that will set capacity prices for the 2029/2030 and 2030/2031 delivery years and quite possibly longer. Consequently, Block 1's demand-side approach to reducing zonal capacity obligations and BGS procurement obligations is the only way DERs like BTM energy storage can provide ratepayers relief from high capacity prices in the near term.

Whereas capacity savings arise from reduced forecast BGS procurement obligations, transmission savings come from actual metered reductions during the transmission CPs on which Network Service Peak Load ("NSPL") obligations are calculated. NSPL obligations are then used to allocate Network Integration Transmission Service ("NITS") charges to network customers. The BCA therefore applies the annual NITS rate to the avoided NSPL obligation. To address the possibility that NITS rates may adjust over time to recover the applicable transmission revenue requirement, the analysis assumes that the relationship among demonstrated peak reductions, their recognition in PJM load forecasts, and the resulting NSPL allocations provides a reasonable basis for estimating transmission benefits without separately quantifying potential changes in DFAX-

based or similar power-flow cost allocations. Because NSPL is based on actual 1 CP load, these savings can be expected to begin in the calendar year following the relevant performance year rather than through the three-tranche BGS procurement cycle. As a conservative timing assumption, however, transmission benefits are modeled as accruing on the same phase-in schedule as the BGS procurement cycle, thereby allowing time for program impacts to be demonstrated and incorporated into applicable PJM forecasting and allocation processes. See Appendix G for further methodological detail.

Furthermore, Staff does not recommend designing the initial block around locational distribution procurement because Block 1 is principally intended to capture statewide capacity and transmission savings through a simple, scalable structure, and modeled distribution benefits represent a smaller share of total benefits. Staff nevertheless agrees with DRC that distribution-deferral value should not be credited merely because a battery enrolls. Staff's BCA cases accordingly discount or remove altogether any distribution benefit the program could deliver. An EDC may attribute a distribution benefit in its BCA to reasonably identified constraints and should: describe the conventional investment that could be avoided or deferred, quantify the required timing and performance, and explain how the resource is expected to affect the EDC's capital plan, revenue requirement, or customer bills. EDC reporting must distinguish projected from realized distribution benefits. EDCs may also propose events or future refinements targeting specific communities, feeders, or other local constraints where they demonstrate incremental ratepayer value. This approach avoids overstating generic distribution benefits while preserving the ability to capture and validate locational value when the necessary evidence exists. The separate mechanism for reflecting Block 1 in PJM's load forecast is addressed in the response to Issue 5.

To ensure that program evaluation is informed by realized performance and customer outcomes, the EDCs shall file an Annual Report. The Annual Report shall serve as the primary mechanism for assessing whether the program is delivering the customer and system benefits contemplated at the time of program approval. Through ongoing measurement of enrollment, operational performance, expenditures, savings, and bill impacts, Staff and stakeholders will be able to compare realized results against forecasted expectations.

In conclusion, Staff's analysis supports proceeding with the defined initial block, but Staff agrees that projected benefits must be tested against timing and downside risk. The BCA therefore includes a base case along with two sensitivity cases, as described above. EDCs are

directed to conduct their own BCA cost tests and filings must provide the assumptions, formulas, workpapers, bill impacts, and permitted sensitivities required by the MFRs, and annual reporting must distinguish forecasts from actual costs, enrollment, performance, and realized savings. Some assumptions are directives from staff (for example, incentive levels) and some assumptions are subject to EDC revision (for example, program administration costs). These safeguards are sufficient for Block 1 because they expose the principal assumptions to review, prevent modeled benefits from being treated as verified savings, and preserve a record for evaluating future changes. As explained above, Staff does not recommend delaying Block 1 to compare every possible alternative program or market reform; those alternatives involve different objectives, authorities, and implementation timelines, and may be evaluated in later proceedings or future capacity blocks. Staff notes that no later block is authorized by this Order.

# 8. Performance Factor Methodology

**Summary of Comments:** - Stakeholders addressed the proposed minimum-output calculation, alternative methods for measuring performance during Dispatch Events, and the relationship between measured performance and incentive payments.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE

ACE was the only utility to substantively address the Performance Factor framework. It recommended a consistent statewide methodology that evaluates measurable outcomes, including delivered kW and kWh, dispatch responsiveness, signal adherence, and availability, using auditable AMI and device-level data. ACE did not state whether the proposed Average Min Discharge methodology should be retained, replaced with average discharge, or compared with methodologies used in other programs; instead, it requested clear rules governing partial performance, customer overrides, and nonperformance caused by distribution-system constraints.

ACE recommended that the Board clearly define how the Performance Factor affects incentive payments, including the treatment of partial performance, customer overrides, and nonperformance caused by distribution-system constraints. It also recommended allowing EDCs to refine measurement methodologies, data-validation processes, and performance metrics as technologies and program experience evolve, provided that any refinements preserve transparency, accountability, and

consistent statewide objectives. ACE further recommended retaining flexibility to adjust maximum event duration, seasonal event limits, and minimum advance-notice requirements based on utility needs and lessons learned following program launch.

**ii. DRC**

DRC evaluated the Performance Factor primarily through the principles of verification, comparability, and ratepayer value. It recommended uniform statewide standards connecting performance-based compensation to measurable and independently verifiable delivery during defined events. Under its proposed framework, performance calculations would be supported by consistent event definitions, measurement protocols, validation requirements, and reporting across EDC territories.

DRC recommended device-level measurement sufficient to verify charging and discharging during Performance Intervals. It considered device-level metering and EDC validation reasonable where those functions can be implemented through existing AMI, manufacturer, aggregator, and EDC capabilities with auditable data quality and without unnecessary new control or data platforms. DRC also recommended event-level reporting of enrolled and available kW, dispatched and delivered kW, event duration, the resulting Performance Factor, forecast accuracy, customer opt-outs, and the estimated capacity, transmission, or distribution value associated with each event.

DRC emphasized that a kW of performance should have the same meaning across EDC territories. It therefore recommended uniform performance, measurement, validation, and reporting requirements to prevent differences in EDC event rules or implementation practices from making the performance obligation easier or harder to satisfy in one service territory than another.

DRC recommended that compensation increasingly follow verified delivery as program experience develops and that actual Block 1 performance inform incentive levels for subsequent blocks. It requested annual reconciliation comparing authorized and actual incentive and administrative expenditures, installed and delivered MW, Performance Factors, and net benefits. DRC also recommended reviewing subscription pace, installed costs, project attrition, dispatch performance, customer and aggregator retention, administrative costs, realized capacity and transmission value, additional revenue streams, and demonstrated distribution deferrals before establishing future incentive levels. Where actual experience shows ready subscription at the applicable rate, achievement of storage-deployment goals, or availability of additional

revenues, DRC recommended reducing future incentive rates to prevent over-subsidization and limit ratepayer burdens.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; Energy Hub; Every Electric Inc.; Koolbridge Energy; Lunar Energy; PowerFlex; Prologis; RExChain; Soltage; Trinity Solar; Uplight; Voltus; Xura; BTM Coalition (Tesla) – Dominic Gatti; RExChain – Siddika Pasi; CleanPeak Energy Group – Ed Levene; Energy Hub – Miriam Fuchs; BTM Coalition (Sunrun) – Thad Culley; and Powerplex – Jacqueline Piero

Commenters in this category generally opposed using the lowest-output interval to determine performance for an entire Dispatch Event. The BTM Coalition, Energy Hub, PowerFlex, Prologis, RExChain, Soltage, Uplight, Voltus, Xura, Dominic Gatti, and Miriam Fuchs supported compensation based on average verified kW delivered across the applicable Performance Intervals, reasoning that one low-output interval should not discount otherwise valuable performance. Energy Hub observed that average-output settlement is used in programs such as Massachusetts' ConnectedSolutions and residential or small-commercial battery programs in Connecticut, Rhode Island, Maine, and Arizona. Every Electric, Trinity Solar, and Jacqueline Piero recommended measuring performance against a sustainable or nominated commitment rather than maximum nameplate output. Koolbridge supported retaining an auditable Performance Factor but recommended separately evaluating performance across different event types, while Lunar Energy supported the basic structure of performance-based compensation tied to verified delivery.

These commenters frequently connected the methodology to the effective value and financeability of the incentive. They cautioned that the minimum-output calculation makes payments under the stated $200/kW-year rate difficult to predict and may discourage enrollment or investment. RExChain explained that, when Awarded Storage Capacity exceeds the output a battery can sustain throughout an event, annual compensation effectively becomes a function of usable energy capacity and event duration rather than declared kW. At the proposed four-hour maximum duration, it calculated an effective rate of $50 per usable kWh-year. Separately, RExChain applied the methodology to Staff's illustrative 11.5-kW/13.5-kWh battery and cited the resulting 23.5% Performance Factor and approximately $540 annual payment to demonstrate the difference between the headline incentive rate and expected compensation. The BTM Coalition similarly recommended replacing the percentage calculation with the more transparent formula of average delivered kW multiplied by the

incentive rate. Positions on the underlying rate differed: Lunar Energy supported the proposed $200/kW-year rate and ten-year term, Soltage supported retaining $200 if applied to average dispatch, and Prologis and Ed Levene recommended higher compensation in connection with C&I participation or shorter-duration obligations. Across these positions, commenters generally emphasized that the stated incentive should reflect realistically deliverable performance and produce revenue that customers and financing parties can reasonably estimate.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties; MSSIA; New Jersey Clean Energy Ventures; Vote Solar; and NJ Solar Energy Coalition – Fred DeSanti

Advanced Energy United, Clean Peak Energy Group, the Joint Clean Energy Parties, Vote Solar, and Fred DeSanti recommended replacing the minimum-output calculation with average verified output across the applicable Performance Intervals. They reasoned that the proposed methodology allows one low-output hour to determine compensation for an entire event, understates the service actually delivered, and may discourage participants from maximizing output during the intervals of greatest grid need. Advanced Energy United referenced Connecticut's use of average verified performance, while the Joint Clean Energy Parties cited Massachusetts' use of average kW. Clean Peak Energy Group proposed using average discharge for compensation while allowing a separate reasonable minimum-performance standard to protect sustained availability. MSSIA proposed a different structure—a fixed annual payment based on energy capacity, expressed in dollars per kWh, subject to a performance requirement—while New Jersey Clean Energy Ventures emphasized defining the complete performance calculation before enrollment and limiting standard events to three hours so that residential batteries can perform consistently throughout the incentive term.

Several associations also maintained that the Performance Factor must be considered together with the incentive rate and operating requirements. The Joint Clean Energy Parties recommended $250 per average delivered kW-year, Fred DeSanti recommended $300 per average AC kW, and Vote Solar supported $300/kW in combination with an increased event obligation. Advanced Energy United similarly supported higher compensation, noting that deliverable capacity during multi-hour events may be substantially below enrolled nameplate capacity. Clean Peak Energy Group recommended reevaluating the proposed $200/kW-year

rate in light of the four-hour event requirement and the final Performance Factor methodology. These commenters generally cautioned that a nominal maximum incentive may overstate expected participant compensation if the minimum-output methodology materially reduces the payment ultimately earned.

**v. Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft

Croft recommended allowing a participant to elect an Awarded Storage Capacity below the battery's nameplate rating, based on the output the system can sustain throughout a four-hour Dispatch Event. She explained that, because the proposed payment formula effectively produces a payment equal to the incentive rate multiplied by minimum output regardless of the capacity initially awarded, a lower sustainable nomination would not increase ratepayer costs. In her view, this approach would release additional capacity within the block, better align the award with deliverable performance, and create a more predictable obligation that financing parties could underwrite.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power; Syntropic Capital Partners; and Individual – Stanislav Jaracz

Syntropic Capital Partners recommended measuring performance against average discharge or delivered energy across a Dispatch Event rather than the minimum interval. It also requested that the Board publish expected Performance Factor ranges for representative battery sizes and event patterns so that customers and financing parties can evaluate realistic revenue. Stanislav Jaracz similarly recommended using delivered kWh rather than kW as the performance metric, reasoning that an energy-based calculation would be fairer. Base Power supported verified, performance-based compensation and a common Performance Factor tied to delivered output but did not expressly choose between minimum-output and average-output settlement.

Syntropic directly connected the calculation to financeability, observing that the proposed methodology could reduce a nominal $200/kW-year incentive to approximately $540 annually for the illustrative battery operating at a 23.5 percent Performance Factor. It maintained that a fixed ten-year rate provides limited underwriting value unless participants can reasonably forecast the payment they will actually receive. Jaracz additionally recommended monthly incentive payments, while Base Power did not

identify the minimum-output calculation as a reason to modify the underlying incentive rate.

**Board Staff Response:**

Staff recommends retaining a sustained-discharge methodology because the capacity and transmission value Block 1 is intended to procure depends on reliable output during the critical hour, not average output across a dispatch event that could mask a material decline when the system peak occurs. Staff recognizes that technology providers, other market participants, and several trade associations favored average verified output, delivered energy, or performance against a nominated commitment because those approaches would make payments more predictable and avoid allowing one low-output interval to determine compensation for an entire event. Staff does not adopt those alternatives because they could compensate energy delivered outside the critical interval as though it provided equivalent peak value; however, Staff's new recommendation for a three-hour event limit and proportional payment structure mitigates the concern that the methodology could unduly discount otherwise useful performance. For each EDC Dispatch Event, performance will be based on the lowest average hourly discharge among the event's one-hour Performance Intervals, and the annual Performance Factor will equal the average of those EDC Dispatch Events' minimum outputs relative to Awarded Storage Capacity. This method does not treat a momentary one-minute fluctuation as zero performance; it uses the average discharge during the lowest-performing one-hour interval. Applying one uniform formula across all EDCs, supported by device-level interval data, implements ACE's and DRC's emphasis on uniform, auditable, and independently verifiable measurement and ensures that a kW of compensated performance has the same meaning statewide.

Other commenters proposed retaining a sustained-performance requirement while allowing participants to nominate a lower level of Awarded Storage Capacity. Staff declines to adopt this recommendation because such a change could have the effect of materially increasing the size of Block 1. That would upset the balance Staff sought to strike between gaining a meaningful amount of BTM storage capacity in Block 1 and limiting ratepayers' cost exposure if experience shows that the proposed Block 1 incentive levels over-incentivize BTM energy storage. Please see Staff's response to comments in the Block Size section for further discussion on this point.

Staff recognizes that the sustained-discharge methodology produces lower and less certain payments than average-output settlement for batteries whose output declines during an event. Staff addresses that

concern by reducing the maximum event duration from the four hours discussed in the Straw Proposal to three hours, aligning the obligation more closely with commonly available residential configurations, and by defining the $200/kW-year and $100/kW-year amounts as maximum payments rather than guaranteed revenues. Annual payments remain proportional to verified performance, so ratepayers do not pay the full incentive where a resource does not sustain the service on which the claimed benefits depend. Average-output settlement is not adopted because it could compensate energy delivered outside the critical interval as though it provided equivalent peak value. The Board may consider prospective changes after operating data are available, but settled performance and existing awards will not be retroactively recalculated.

## 9. 70% Passthrough Requirement

**Summary of Comments:** - Stakeholders addressed whether a minimum percentage of the incentive should be passed through to Host Customers and how that requirement would affect different ownership, financing, aggregation, and customer-compensation models.

i. **Utilities**

Commenter(s) Referenced in This Summary: None

The utilities did not substantively address whether the proposed 70% customer pass-through is necessary or whether it should vary among customer-owned, aggregator-managed, leased, or third-party-owned systems. Accordingly, no utility position should be inferred regarding retention, removal, enforcement, or modification of the requirement.

ii. **DRC**

DRC recommended annual reporting of incentive receipts, other public subsidies, tariff savings, aggregator compensation, customer pass-through amounts, wholesale revenues, and realized project returns on an aggregated and confidential basis sufficient for Board and DRC review. It also recommended that the BCA test different aggregator pass-through assumptions and that retrospective reporting compare forecast and actual customer pass-through results. These requirements would allow the Board to assess the distribution of incentive value, project economics, and whether future incentive levels remain appropriately priced, but they do not establish a preferred customer-pass-through percentage.

DRC separately recommended a resource-level compensation ledger identifying GSESP incentives, aggregator payments, tariff savings, public

and tax-supported incentives, wholesale revenues, the obligations purchased by each payment, and the relevant time periods. It also sought anti-duplication controls and limits on total ratepayer-funded compensation. Those recommendations address aggregate compensation and overlapping value streams; they do not determine how a nonduplicative GSESP payment should be divided between an aggregator or TPO and the Host Customer.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; Energy Hub; Every Electric Inc.; RExChain; Voltus; BTM Coalition (Tesla) – Dominic Gatti; CleanPeak Energy Group – Ed Levene; and Energy Hub – Miriam Fuchs

Technology providers proposed different changes to the 70% cash pass-through requirement for TPO and portfolio-ownership models. Voltus recommended removing the requirement and, if the Board retains a customer-value protection, limiting it to service aggregators managing customer-owned resources. Ed Levene similarly recommended exempting TPOs. EnergyHub and Miriam Fuchs stated that a uniform requirement may be incompatible with different residential-storage business models and difficult to enforce, with EnergyHub supporting flexible assignment of incentives for TPO arrangements. The BTM Coalition recommended removing or reforming the requirement because TPOs finance, own, maintain, and assume performance risk for the underlying equipment while providing customer value through varied commercial arrangements. It also cautioned that requiring EDCs to review provider pricing and financing arrangements could create substantial administrative burdens and require disclosure of commercially sensitive information.

Every Electric supported retaining the 70% threshold and plain-language disclosure requirement but recommended allowing a TPO that also performs the aggregation function to satisfy the threshold through documented in-kind value, including no-cost equipment, bill savings, and backup-power benefits. RExChain recommended allowing TPOs to comply through reduced lease or power-purchase-agreement payments, no-cost system provision, or equivalent quantified consideration disclosed before enrollment; alternatively, it proposed exempting TPOs from a cash-remittance requirement and applying a disclosure obligation instead. The BTM Coalition favored removing or reforming the requirement, but recommended that, if retained, reduced lease prices, solar-payment credits, fixed annual payments, direct revenue shares, and combinations of those mechanisms qualify, with the percentage calculated against

compensation actually earned. Dominic Gatti recommended applying the requirement to bought-down leases. The proposals therefore ranged from retaining the threshold with broader compliance methods to exempting TPO structures or removing or reforming the requirement.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties; NJ Solar Energy Coalition – Fred DeSanti; and New Jersey Environmental Justice Alliance (Solar Energy Industries Association) – Joan White

Trade associations generally supported ensuring that customers receive meaningful program value but opposed applying a rigid 70% cash-payment formula to every business model. Advanced Energy United stated that a fixed pass-through threshold is inconsistent with some residential storage models and recommended limiting it to customer-owned assets if the requirement is retained. Clean Peak Energy Group recommended distinguishing service-only aggregators from TPOs that finance and own equipment and bear long-term financing, equipment, maintenance, replacement, acquisition, and performance risks. The Joint Clean Energy Parties similarly recommended that the requirement apply to aggregators managing customer-owned devices, not TPO systems, although they proposed that 70% could remain a default if customers are permitted to affirmatively select a fully disclosed alternative arrangement.

These commenters emphasized that TPO and lease customers may receive program value through reduced upfront costs, lower lease payments, bill credits, fixed annual payments, or other contractual benefits rather than a direct percentage of annual incentive revenue. The Joint Clean Energy Parties recommended allowing all such mechanisms to qualify and measuring compliance against the compensation actually earned. Fred DeSanti recommended allowing the parties to negotiate the allocation where the system is leased, while Joan White supported the underlying customer-benefit concept but requested clarification concerning TPO arrangements in which anticipated program revenue is already reflected in lease pricing. Across these comments, disclosure of the expected incentive, its recipient, the customer's economic benefit, associated fees, and the allocation of operational and performance risks was presented as an important consumer-protection measure.

**v. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: Cammie Croft; New Jersey Environmental Justice Alliance

Cammie Croft supported the 70% threshold and plain-language disclosure for service aggregators acting on behalf of Host Customers but requested clarification regarding a participant that is both the TPO and aggregator. For an owner-participant that finances the battery, she recommended using a defined host-benefit standard in place of a 70% cash remittance. That standard could require no upfront cost, backup power, no household debt or clawback, a defined share of program value, and plain-language disclosure of the value retained by the owner. Croft reasoned that requiring an owner-participant to remit 70% of the incentive in cash could consume revenue needed to finance the equipment and foreclose no-upfront-cost models intended to serve households with affordability constraints.

The New Jersey Environmental Justice Alliance supported a binding pass-through requirement but recommended replacing the proposed 70% floor with a 50% direct customer pass-through, accompanied by a related 25% OBC-focused revenue requirement and a 10% social multiplier for resources in highly energy-burdened areas. It proposed providing customer share through visible bill credits, reduced retail rates, or direct payments to ensure that publicly supported incentives produce verifiable household benefits rather than being retained principally by developers. The filing describes the 25% OBC component in two different ways: as one-quarter of total program revenues directed to an OBC Resilience Fund and, in its proposed Section 5.J language, as at least 25% of the 50% customer pass-through directed to qualifying OBC households. That distinction would require clarification before the proposal could be translated into a single revenue-allocation formula. Climate Jobs NJ did not substantively address this topic.

**vi. Program implementers, consultants, and academic commenters**

Commenter(s) Referenced in This Summary: Base Power; Syntropic Capital Partners

Base Power recommended limiting the 70% floor to systems owned by the Host Customer. It argued that, in a TPO or supplier-owned fleet, the provider finances, installs, owns, operates, and maintains the battery, while the customer receives value through the installed equipment, backup power, bill savings, and the pricing of the retail product rather than through a discrete incentive payment. Base Power therefore recommended exempting TPO and supplier-owned fleets and relying on accessible pre-enrollment disclosure of the incentive structure and customer-benefit methodology.

Syntropic Capital Partners supported retaining the 70% floor as a consumer-protection measure, particularly for customer-owned, debt-financed systems. It cautioned that reducing the floor could leave customers with less program revenue to pledge toward repayment and thereby restrict financing access. Syntropic requested clarification that a separate, voluntary, fully disclosed financing agreement, and a customer's decision to use received incentive payments to repay a loan, does not reduce the aggregator's pass-through obligation. It also recommended distinguishing a passive capital provider from an Aggregator and requiring separate plain-language disclosure of financing principal, interest rate, term, total repayment obligation, and the consequences of moving or leaving the program.

**Board Staff Response:**

Staff does not recommend a mandatory 70% customer passthrough for the initial block. Technology providers, aggregators, trade associations, and other market participants generally agreed that customers should receive material and transparent value, but explained that a single pass-through percentage would operate differently across customer-owned systems, service-only aggregation, leases, financing arrangements, TPO structures, and supplier-affiliated models. Environmental and consumer commenters proposed different binding customer-benefit structures. DRC did not endorse a particular percentage but requested reporting on customer pass-through, aggregator compensation, tariff savings, other revenues, and project economics. On this record, a uniform percentage could apply to no-upfront-cost and third-party-owned arrangements even where the customer receives meaningful value through equipment, backup capability, reduced lease pricing, bill credits, or other disclosed consideration. Staff therefore recommends requiring clear customer disclosures and EDC reporting on TPO ownership configurations, and customer-facing arrangements as provided in the MFRs rather than adopting a rigid allocation formula. These safeguards are sufficient for the initial block because; they make the recipient and form of customer value reviewable; allow Staff to identify whether a business model produces inadequate customer benefits; and avoid prescribing a formula before comparable operating data exist. The Board may adopt prospective customer-benefit or pass-through standards if program experience demonstrates that additional protection is warranted.

Staff acknowledges the importance of ongoing data collection for continued program refinement, and recommends using the EDCs' required Annual Reporting function and Staff's Interim Report as a way to monitor program development. Staff elects to not include certain data

requested by DRC as EDC reporting requirements, such as the provision of customer savings, tariff arrangements, and project level economics. In addition to the administrative burden it would levy onto participants, participants' self-reported savings and project returns will not be uniform across the fleet due to varying participation models, service territory, and the bespoke value participants each attribute to resilience. The value of this data will be limited, and Staff believes there will be sufficient detail to assess appropriate incentive levels on a going-forward basis. For reasons stated in Item 1 above, pass-through tariff reporting is not feasible. However, EDCs will be reporting participation levels on TOU tariff structures and the split of TPS vs. BGS participation. That said, Staff sees potential value in DRC's suggested resource compensation ledger, but believes further stakeholder consultation regarding its administrative feasibility is needed before the Board orders its establishment. Staff therefore recommends that PowerUp NJ working group consider such a compensation ledger so the Board can render a decision on this proposal in the near future.

## 10. Distributed Energy Resource Management System ("DERMS") Ecosystem

**Summary of Comments:** - Stakeholders addressed whether DERMS capabilities are required for Block 1, the respective functions of Grid DERMS and Edge DERMS, and the appropriate roles of EDCs, aggregators, OEMs, and third-party platform providers.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G; JCP&L; RECO

The utilities generally proposed launching Block 1 using existing utility systems or contracted platforms while developing more robust DERMS capabilities as program requirements mature. ACE recommended using existing AMI, utility systems, aggregator and OEM platforms, and Grid-Edge DERMS capabilities during Block 1 while developing Utility DERMS capabilities over time. PSE&G proposed using its existing contracted Edge DERMS arrangements initially if EDCs are assigned responsibility for dispatch communications and performance-data collection and validation. JCP&L emphasized scalable capabilities for telemetry, communications, validation, operational visibility, and future integration, while RECO proposed using a third-party aggregator together with its existing Demand Response Management System.

ACE expressly distinguished Edge DERMS from Utility DERMS. It described Edge DERMS as supporting device and aggregation functions,

including enrollment, telemetry, state-of-charge monitoring, dispatch execution, and customer-facing controls. ACE described Utility DERMS as providing the distribution-system visibility and coordination needed to manage voltage, capacity constraints, local reliability needs, and competing dispatch signals. Under ACE's phased model, Edge DERMS platforms would support Block 1 while Utility DERMS capabilities mature to support more granular distribution operations.

The utilities generally supported EDC responsibility for identifying grid needs, calling or coordinating Dispatch Events, validating performance, and retaining sufficient operational visibility and reliability authority. They nevertheless recognized a substantial role for third-party platforms. ACE recommended that aggregators, OEMs, and implementation vendors manage device-level operations through Edge DERMS platforms; PSE&G anticipated contracting with Edge DERMS providers; and RECO proposed combining EDC dispatch authority with third-party aggregator services. No utility recommended that each EDC immediately build a proprietary system that directly controls every participating battery. NJNG did not substantively address the DERMS ecosystem.

**ii. DRC**

DRC recommended using existing AMI, demand-response systems, customer-data systems, communications networks, and manufacturer and aggregator platforms to implement Block 1 wherever those capabilities can perform the required functions at lower cost. It considered Staff's proposed device-level measurement and EDC validation approach reasonable if existing systems can support auditable data quality. DRC recommended requiring an EDC proposing a new DERMS or control platform to demonstrate the specific operational need and explain why existing capabilities or lower-cost alternatives are insufficient.

DRC proposed evaluating DERMS investments based on required functions, existing capabilities, incremental costs, and funding sources. It recommended that each EDC inventory its AMI, demand-response, customer-data, communications, DERMS or distributed-management, interconnection, and aggregator-interface capabilities and identify the Block 1 function served by each proposed investment. The EDC should also identify the lower-cost alternatives considered, the portion of the platform attributable to Block 1, and every other docket or rate mechanism through which the same capability is or will be funded.

DRC cautioned against charging Block 1 for preexisting or multipurpose DERMS and grid-modernization investments already included in base rates, Triennium programs, AMI approvals, VPP budgets, or other proceedings. At the same time, it cautioned against the inverse error: if a

new Block 1-specific interface or integration is necessary and provides measurable program benefits, its incremental cost should be included in the BCA even if the EDC proposes to recover it elsewhere. DRC therefore recommended isolating the costs actually caused by Block 1, preventing duplicate recovery, assigning directly attributable costs according to cost causation where practicable, and evaluating the full all-in cost of the selected architecture.

DRC supported EDC-directed dispatch to the extent necessary to ensure that ratepayer-funded resources respond at the time and location of system need, but it did not presume that direct EDC device control or an EDC-owned DERMS is the only or least-cost model. It recommended comparing direct EDC control, aggregator-mediated dispatch using standardized signals and third-party device-management platforms, and tariff- or price-based response where the required behavior can be obtained without a separate control platform. This approach could preserve EDC operational authority while avoiding duplicative EDC device-control systems.

DRC recommended that the Board establish functional requirements for dispatch timing, reliability, telemetry, verification, cybersecurity, and override rules, while requiring each EDC to justify the least-cost architecture satisfying those requirements. The comparison should consider incremental technology costs, communications reliability, latency, customer opt-out rights, measurement accuracy, vendor lock-in, and the ability to support multiple future DER programs. DRC did not assign the DERMS ecosystem exclusively to either EDCs or third parties, but it expressly recognized a role for aggregators and their platforms and cautioned that EDCs should not use control over interconnection, dispatch information, or system-need data to disadvantage third-party aggregators or favor utility-affiliated solutions.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; Energy Hub; Every Electric Inc.; Koolbridge Energy; Lunar Energy; PowerFlex; RExChain; Solar Landscape; Uplight; Weave Grid; and Energy Hub – Miriam Fuchs

Commenters in this category differed on whether DERMS should be described as “required,” but generally converged on using existing third-party and device-management capabilities rather than constructing new utility-controlled platforms for Block 1. The BTM Coalition, Energy Hub, and Uplight considered an Edge DERMS or common Edge DERMS/VPP architecture necessary or strongly preferable for enrollment, availability

management, dispatch communications, telemetry, M&V, and settlement. Energy Hub stated that existing Edge DERMS platforms could support launch without waiting for EDC Grid DERMS development. Uplight additionally recommended using a common Edge DERMS architecture for both GSESP and the VPP Interim Program. In contrast, Every Electric, PowerFlex, and RExChain agreed with Staff that a new DERMS is not required if EDCs issue standardized signals and participants use existing device platforms and telemetry to execute and verify performance. These positions largely reflect different views about platform terminology and procurement rather than disagreement that Block 1 requires reliable enrollment, communications, dispatch, telemetry, and settlement functions.

The commenters drawing a distinction between DERMS layers generally described Grid DERMS as a utility-facing system for distribution visibility, constraint management, and coordination across grid assets, while Edge DERMS connects the EDC with customer devices, OEMs, aggregators, and portfolios. The BTM Coalition and Energy Hub argued that a full Grid DERMS is not necessary for Block 1, whereas an Edge DERMS can provide the operational functions needed for a timely launch. Uplight and Weave Grid emphasized that an Edge DERMS can also map resources to feeders, transformers, substations, and local constraints, allowing the program to capture more granular distribution benefits. Lunar Energy similarly supported an aggregator Edge DERMS layer that manages state of charge, backup reserves, solar production, and other site-specific conditions. PowerFlex cautioned, however, that reliance on a single EDC-selected Edge DERMS provider could restrict participating technologies and competition if the program becomes limited to that provider’s integrations and capabilities.

These commenters generally recommended that EDCs identify the grid need, establish operating parameters, and call or authorize events, while aggregators, OEMs, Edge DERMS providers, or resource owners execute device-level dispatch. Energy Hub, Lunar Energy, Uplight, Koolbridge Energy, Every Electric, RExChain, and Solar Landscape supported variations of this signal-and-execute structure. Uplight and Weave Grid placed greater emphasis on EDC-directed, distribution-aware orchestration, while PowerFlex and RExChain emphasized participant control and cautioned against direct utility control or duplicative utility investment. Across these positions, commenters generally supported open interoperability, standardized signals and data, auditable device-level telemetry, and EDC reliability authority without requiring each EDC to independently integrate with and directly operate every participating battery.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties; New Jersey Clean Capacity Coalition; and New Jersey Environmental Justice Alliance (Solar Energy Industries Association) – Joan White

These commenters did not recognize a relevant distinction between Grid DERMS and Edge DERMS. The Joint Clean Energy Parties agreed that a full Grid DERMS should not be a prerequisite for Block 1 but recommended that the MFRs expressly provide for Edge DERMS capabilities. They maintained that an Edge DERMS can handle enrollment, event communications, device-level performance data, and settlement through existing OEM and aggregator integrations. They recommended that utilities contract with existing "out-of-the-box" Edge DERMS providers rather than develop bespoke utility software, citing cost, implementation time, interoperability, and vendor-lock-in concerns. Clean Peak Energy Group similarly recommended allowing qualified existing third-party battery-control platforms to receive and execute EDC dispatch instructions, subject to functional interoperability, telemetry, M&V, response-time, availability, data-security, and cybersecurity requirements.

Advanced Energy United and the Joint Clean Energy Parties supported an operating structure in which EDCs call Dispatch Events while participants, aggregators, OEMs, or other approved platforms execute the response. Joan White likewise described Edge DERMS as the intermediary layer between EDCs and individual assets and requested greater clarity regarding the aggregator and DERMS ecosystem. The New Jersey Clean Capacity Coalition's comments were directed principally toward FTM-distribution storage, but it similarly argued that inverter telemetry and device-level measurement can provide auditable verification and that program development should not be delayed pending costly utility Grid DERMS deployment. Collectively, these commenters favored EDC direction of grid-service needs combined with competitive third-party execution, rather than routine direct utility control through newly constructed proprietary platforms.

**v. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: Cammie Croft

Cammie Croft agreed with Staff that a new DERMS is not necessary for Block 1. She recommended using device telemetry delivered through a Licensed Aggregator as the settlement basis, with the EDC issuing

dispatch instructions and the participant or Aggregator executing them. She maintained that this structure would provide auditable performance data without duplicative utility-control infrastructure and recommended carrying the same settlement approach into the future VPP tariff.

Croft proposed an architecture in which participants or third parties manage device-level control, while EDCs retain authority to call Dispatch Events and exercise a bounded, documented emergency override for local reliability conditions. She recommended evaluating any additional control platform based on whether its incremental ratepayer savings exceed its implementation, communications, and administrative costs.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power

Base Power agreed with Staff that DERMS is not required to operationalize Block 1. It recommended that participants operating storage fleets receive EDC dispatch instructions at the aggregation level, execute those instructions across their own systems, and report portfolio-level performance data, while retaining device-level data for EDC audit. Base Power maintained that AMI interval data and aggregation-level telemetry are sufficient for wholesale accounting and program settlement without requiring a new utility DERMS.

Base Power therefore favored participant-managed dispatch platforms rather than an EDC-owned system providing direct device-level control. It argued that direct EDC control would require additional DERMS or equivalent utility investment, complicate portfolio management of state of charge, backup reserves, and other value streams, and separate operational responsibility from the Participant that bears performance risk. Base Power supported standardized EDC dispatch signals and audit rights while retaining Appendix I's interoperability standards as voluntary guidance. Base Power did not recognize a relevant distinction between Grid DERMS and Edge DERMS. The remaining commenters in this category did not substantively address the DERMS ecosystem.

**Board Staff Response:**

Staff does not recommend requiring a full Grid DERMS as a prerequisite to Block 1. The EDCs generally requested flexibility to use existing utility systems and contracted capabilities, while technology providers, aggregators, trade associations, and other market participants generally favored a signal-and-execute structure using existing OEM, Aggregator, or Edge DERMS platforms rather than

duplicative utility device-control systems. DRC likewise recommended evaluating required functions, existing capabilities, incremental costs, and lower-cost alternatives rather than assuming a new platform is necessary. Accordingly, an EDC may use existing systems, qualified third-party platforms, or OEM systems, or another architecture if the selected approach supports reliable dispatch, device-level telemetry, measurement, settlement, cybersecurity, auditability, and reporting. Each EDC filing must identify the Block 1 function supported by any proposed system or integration cost, inventory existing capabilities, compare lower-cost alternatives, allocate only the portion attributable to Block 1, identify recovery requested in any other proceeding, and include every genuinely incremental cost in the BCA. These safeguards allow EDCs to retain authority to identify grid needs and call events while participants execute dispatch and remain accountable for performance. They also address DRC's cost-causation and duplicate-recovery concerns by preventing Block 1 from funding a multipurpose platform merely because it may be useful, without excluding a demonstrated investment that is necessary and cost justified.

## 11. EDC Recovery

**Summary of Comments:** - Stakeholders addressed recovery of incentive, administrative, technology, and implementation costs; potential EDC performance incentives; the required support for program-administration budgets; and appropriate peak-shaving objectives.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G; JCP&L; RECO; NJNG

The utilities generally supported timely recovery of prudently incurred Block 1 costs, although they differed regarding the appropriate accounting and recovery treatment. ACE and JCP&L supported recovery through a non-bypassable, reconcilable tariff rider and recommended deferring and amortizing customer incentive payments over the period in which program benefits are realized. ACE proposed applying the authorized return to capital investments and the unamortized incentive balance, while JCP&L additionally proposed recovering depreciation and a deferred return on capital investments and applying carrying costs to over- or under-recovered balances. RECO recommended preserving flexibility to treat administration, incentives, and related labor costs as a regulatory asset amortized over a period aligned with the expected life of participating storage resources. It also supported rolling enrollment because residential and small-commercial storage resources become eligible and operational throughout the year. RECO recommended that cost-recovery mechanisms

accommodate timing differences among customer enrollment, incentive payments, and program cost recovery without creating unnecessary administrative complexity.
ACE and PSE&G supported consideration of utility performance incentives, but proposed different approaches. ACE recommended addressing such incentives through the longer-term VPP/GridFlex framework and tying them to measurable operational and system outcomes—including timely interconnections, accurate administration and data validation, peak load reduction, avoided capacity costs, distribution investment deferrals, and reliability—rather than installed capacity alone. PSE&G recommended an energy-efficiency-style mechanism that rewards utilities for meeting or exceeding storage targets. JCP&L did not propose a utility incentive and instead recommended first evaluating Block 1 through objective measures such as enrollment, available capacity, dispatch performance, and actual peak reduction. RECO and NJNG likewise did not propose a specific shareholder incentive mechanism.

ACE, PSE&G, JCP&L, and RECO recommended that EDC filings identify the principal functions driving administrative costs, including labor, customer enrollment and education, marketing, application processing, aggregator and contractor management, software and platform services, cybersecurity, telemetry and data management, dispatch, M&V or EM&V, customer support, reporting, compliance, and future VPP integration. PSE&G recommended using the level of detail required for existing energy-efficiency and demand-response programs, while ACE and RECO emphasized retaining flexibility to refine budgets as participation and implementation experience develop. JCP&L additionally stressed transparent estimates and timely recovery of prudently incurred operating and capital costs. NJNG did not prescribe comparable filing details.

The utilities identified peak reduction as a principal program objective, with individual recommendations addressing how that objective should be framed and measured. JCP&L recommended that the Board clarify whether Block 1 is intended to address PJM coincident peaks, individual utility peaks, or localized distribution needs because those objectives may require different dispatch rules and performance measures. ACE and RECO favored high-level outcome requirements with operational flexibility, PSE&G supported maximizing peak-capacity reductions, and NJNG recommended evaluating both peak reduction and sustained performance during prolonged reliability events.

**ii. DRC**

DRC recommended transparent reporting of the revenue requirements and customer-bill impacts associated with the proposed non-bypassable per-kWh charge, disaggregated by customer class and participation status. Its cost-recovery recommendations focused on demonstrating the reasonableness, allocation, and incremental nature of administrative, enabling, implementation, and transaction-specific expenditures.
DRC opposed automatically socializing all Block 1 administrative and enabling costs merely because the program is Board approved. It recommended applying cost-causation principles so that application processing, aggregator licensing, customer enrollment, project-specific technical review, customized data interfaces, device testing, settlement, telemetry review, interconnection studies, dispute resolution, and individualized reporting are recovered through reasonable fees from the applicants, participants, aggregators, or projects causing those costs where practicable. Common costs that demonstrably produce systemwide savings could receive broader ratepayer recovery if supported by an adequate cost-causation showing.

DRC also recommended that the Board identify ways to allocate costs to the primary new load drivers contributing to the need for additional resources, specifically identifying large data center-driven loads and other concentrated energy-usage sectors. The filing does not prescribe a particular tariff, allocation factor, or cost-recovery mechanism for those customers, but it expressly identifies load-driver cost allocation as an issue the Board should address rather than automatically spreading all costs across existing customers.

DRC recommended that each EDC submit a complete, auditable, function-by-function and year-by-year budget separating participant incentives from administration, technology, interconnection, M&V, marketing, data, and other expenditures. EDC filings should identify vendors, staffing assumptions, unit costs, allocation factors, and existing AMI, demand-response, customer-data, communications, DERMS, interconnection, and aggregator-interface capabilities. For every proposed expenditure, the EDC should demonstrate the incremental Block 1 function being provided, why the expenditure is reasonable and necessary, the lower-cost alternatives considered, the portion used by Block 1, and whether the same cost is already recovered through base rates, Triennium programs, VPP budgets, grid-modernization proceedings, AMI approvals, or another mechanism.

For each material cost, DRC requested the proposed accounting and ratemaking treatment, including any deferral, regulatory asset,

amortization, carrying charge, or capital treatment, together with an explanation supporting that treatment. It recommended a cost-causation analysis distinguishing participant-specific, aggregator-specific, project-specific, EDC-systemwide, and statewide costs; reasonable participant and aggregator fee schedules; hard annual and cumulative budget caps; restrictions on transfers among major budget categories; annual reconciliation; and return or credit of unspent or unsupported balances. It also requested sufficient workpapers to test staffing, vendor rates, unit costs, allocation factors, and overlap with other programs, together with express Board authority to disallow unsupported, duplicative, out-of-scope, or imprudently incurred expenditures.

DRC further recommended including every genuinely incremental Block 1 cost in the BCA, even if the EDC proposes to recover it through another proceeding, while preventing duplicate recovery of costs already funded elsewhere. It emphasized that cost-effectiveness should reflect the full all-in cost of obtaining the resource rather than depend on the docket in which a particular expenditure is booked. DRC noted that full enrollment at the proposed maximum incentive could produce approximately $300 million in nominal incentive payments over ten years before administrative and enabling costs, reinforcing its request for firm budget, reconciliation, reporting, and prudence protections.

DRC did not propose or endorse an EDC shareholder incentive, shared-savings mechanism, tiered earnings opportunity, or arrangement allowing EDCs to retain a percentage of capacity, transmission, distribution, or peak-related savings. Its broader position that program compensation and claimed benefits should be tied to independently verifiable net customer savings does not constitute a proposed EDC incentive mechanism. DRC instead sought actual cost, performance, savings, and bill-impact information before additional compensation or program expansion is authorized.

DRC recommended defining the relevant PJM capacity and transmission peak events, linking distribution Dispatch Events to identified local constraints, and measuring whether dispatch affects the obligations, procurement costs, capital plans, revenue requirements, or customer bills used to justify the program. For prospective estimates, EDCs should identify the causal mechanism and expected timing of each benefit, with retrospective reporting used to verify whether those benefits materialized. DRC recommended evaluating program success through verified net customer savings after accounting for incentives, administrative and enabling costs, and reasonably available alternatives.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; Koolbridge Energy; Prologis; RExChain; Solar Landscape; Uplight

The technology-sector commenters generally focused on the accounting and oversight of administrative expenditures rather than proposing EDC shareholder incentives. The BTM Coalition opposed locking the program into a separately identified residential-bill rider and recommended treating program costs as a regulatory asset, subject to prudence review, so that recovery can occur over the multiyear incentive term while the associated benefits are realized. The BTM Coalition did not provide recommendations concerning the components of EDC administrative budgets. The remaining commenters generally did not select a particular cost-recovery mechanism.

Koolbridge Energy recommended task-based itemization that separates one-time implementation costs from recurring per-participant expenses and reports costs at the 50 MW, 100 MW, and 150 MW enrollment milestones. Prologis recommended standardized cost categories, cost-per-kW metrics, quarterly actual-versus-budget reporting, prior approval for material variances or additional capital expenditures, and an explanation of why functions cannot be performed by program participants. RExChain recommended annual category-level budgets, per-project and per-kW benchmarks, staffing and vendor information, and a clear capital-versus-expense allocation. It also proposed two structural protections: an administrative-cost cap of approximately 10% to 15% of disbursed incentive payments, with annual true-ups and refunds of overcollections, and a mandatory statewide application and settlement platform using common forms and shared or jointly procured infrastructure across the EDCs.

Solar Landscape recommended that EDC filings identify major cost categories, distinguish one-time start-up and integration costs from recurring expenses, and disclose costs recovered through grid-modernization, DERMS, PSUP, or other proceedings to prevent duplicative recovery. It proposed common metrics, including administrative cost per enrolled MW or kW, administrative costs as a percentage of total program expenditures, expected participating capacity, and the assumptions underlying material differences among EDC proposals. Solar Landscape also recommended separating administrative costs from participant compensation and evaluating whether the proposed spending enables measurable positive net ratepayer value. Uplight recommended identifying platform, OEM and aggregator integration, enrollment, dispatch, M&V, data-management, settlement, and reporting costs and demonstrating that

those expenditures enable enrolled capacity to deliver the ratepayer benefits used to justify the program.

None of the applicable commenters recommended an EDC shareholder incentive mechanism. The BTM Coalition supported making system peak reduction the principal dispatch objective and coordinating capacity-related dispatch with a Peak Shaving Adjustment or comparable load-forecast modification, while preserving EDC discretion over distribution events.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Energy Efficiency Alliance; Joint Clean Energy Parties; New Jersey Clean Energy Ventures; Public Power Association of New Jersey

The trade associations generally focused on transparency, cost allocation, and the relationship between administrative expenditures and delivered program benefits. The Joint Clean Energy Parties did not recommend a single cost-recovery mechanism but requested that EDC filings distinguish costs recovered through application fees from those recovered through a program rider, incremental costs from functions already funded in existing rates or programs, operating expenses from capital expenditures, and Block 1 costs from expenditures supporting VPP, grid-modernization, PSUP, or other utility initiatives. The Public Power Association of New Jersey separately requested an equitable funding mechanism that avoids inappropriate cross-subsidization while providing municipal electric utilities and the cooperative a meaningful opportunity to participate. The remaining applicable trade associations did not propose a particular rider, regulatory-asset, or revenue-requirement treatment.

Regarding administrative costs, the Joint Clean Energy Parties recommended detailed and comparable EDC filings covering staffing, applications, interconnection coordination, customer and aggregator support, communications, metering, data management, M&V, settlement, incentive administration, cybersecurity, information technology, consultants, legal and regulatory functions, education, and capital investment. They also recommended uniform statewide procedures for program administration, M&V, settlement, and incentive payments. For proposed capital investments, they recommended requiring EDCs to demonstrate that existing systems or lower-cost third-party capabilities cannot perform the necessary functions. They further recommended periodic reporting comparing actual administrative costs with approved budgets. The Energy Efficiency Alliance supported transparency but

recommended presenting program costs together with associated customer-bill and grid benefits so that cost reporting does not discourage participation. New Jersey Clean Energy Ventures cautioned that separate EDC-specific device-control systems and technical requirements could create unnecessary costs and favored execution through aggregators or project owners.

**v. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: Cammie Croft; New Jersey Environmental Justice Alliance

The New Jersey Environmental Justice Alliance recommended conditioning utility cost recovery and incentive eligibility on binding equity outcomes through a performance-based regulatory framework. Its proposal included measurable affordability and equity metrics, quarterly reporting, and proportional clawbacks of previously approved recoveries when required outcomes are not achieved within specified reporting periods. Under this framework, utility compensation would be evaluated based on demonstrated community and equity outcomes in addition to program deployment and system performance.

Cammie Croft recommended that EDC petitions itemize administration by function, benchmark costs against the Triennium 2 programs Block 1 would replace, state administrative costs as a share of incentive payments, and report enrollment and interconnection-processing performance. The New Jersey Environmental Justice Alliance additionally recommended disaggregated reporting of program revenues and benefits, including incentive, capacity-market, and ancillary-service compensation, to support accountability and identify shortfalls affecting overburdened communities. Neither commenter proposed a numerical peak-shaving target.

**vi. Program implementers, consultants, and academic commenters**

Commenter(s) Referenced in This Summary: Base Power; Michael Winka; Peter Fried

Michael Winka recommended applying the same administrative-cost detail and justification requirements used for utility energy-efficiency programs. He also favored a relatively simple initial incentive and administrative framework, with more complex metering, dispatch, and grid-service approaches tested through limited sandbox applications before broader implementation.

Base Power recommended that verified Block 1 reductions be included in each EDC's Peak Shaving Adjustment submission, or an equivalent PJM load-forecast mechanism, and count toward the EDC's peak-demand-

reduction obligations under the VPP framework. Base Power also recommended separating the distribution component of the performance incentive from capacity and transmission value where necessary to recognize services available from third-party-supply customers, although this proposal addressed participant compensation rather than EDC cost recovery. Peter Fried supported peak-demand management as a program objective and identified municipal utilities as potential providers of those benefits. None of the applicable commenters proposed a specific numerical peak-shaving target.

**Board Staff Response:**

Staff recommends treating prudently incurred Block 1 incentives and ordinary program-administration costs as operating expenses recovered via a bill rider in the same Performance Year they are incurred, subject to annual reconciliation and prudence review, rather than as capital investment eligible for a separate equity return. This treatment responds to the EDCs' requests for timely and certain recovery while recognizing DRC's concern that ratepayers should not finance duplicative, unsupported, or unnecessarily capitalized costs. Most Block 1 costs are customer incentives, implementation expenses, contractor costs, data and reporting functions, and other operational or pass-through costs tied to assets the EDCs do not own. Application-fee revenue will be credited against recoverable administrative costs, and an EDC may seek recovery for a demonstrated capital investment or deferred cost only if it identifies the specific Block 1 function the investment provides, explains why existing or lower-cost alternatives are insufficient, demonstrates that the cost is not already recovered elsewhere, and justifies the proposed accounting and ratemaking treatment.

Staff declines to adopt ACE's and JCP&L's recommendation to amortize incentive expenditures and recover them over the life of the program. Block 1 incentives are annual, pay-for-performance incentives rather than upfront incentives. This means allowing full EDC recovery of those expenses in the year they are incurred as a pass-through operating expense already spreads out incentive cost recovery over the life of the program. Staff believes this design renders ACE and JCP&L's amortization approach unnecessary and will spare ratepayers the additional cost of paying a rate of return on any regulatory asset containing deferred incentive expenditures.

Each filing must provide the function-by-function and year-by-year cost detail required by the MFRs, including staffing, vendors, unit costs, allocation factors, existing capabilities, alternatives considered, and

justification for any capital expenditures. These requirements are sufficient to permit recovery of reasonable implementation costs while allowing the Board to disallow unsupported, duplicative, out-of-scope, or imprudent expenditures. Staff does not recommend an EDC shareholder incentive, shared-savings mechanism, or performance incentive in this Order because the initial block should first establish reliable baselines for costs, performance, and realized savings. That said, Staff is open to an approach to EDC earnings that ties EDC profit to outcomes that provide demonstratable benefits to ratepayers. The Board may consider integrating such a mechanism prospectively into the Block 1 design after sufficient operating and EM&V data are available, which will likely be the time the Interim Report is completed.

Staff declines to adopt DRC's recommendation to assign all Block 1 administrative costs directly to participants. First, Staff believes allowing recovery of Block 1 administrative costs from ratepayers generally is consistent with cost-causation principles because even when including administrative costs, the benefits Block 1 provides to ratepayers exceed program costs. Second, assigning administrative costs wholly to participants would effectively decrease the net incentive provided by the Block 1 program, thereby requiring a compensating increase to the headline incentive to drive the same level of program adoption. Thus, assigning all these administrative costs to participants would effectively be an accounting gimmick that would not actually reduce overall Block 1 program costs to non-participants. Third, attempting to recover these costs solely through application fees could make those fees variable and hard to predict, and that uncertainty could inhibit program enrollment and thus lower the benefits Block 1 provides to all ratepayers. Fourth, this approach is simply infeasible because it will be impossible for EDCs to know in advance precisely what their future administrative costs will be or the number of applications they will receive in order to calculate the application fee levels that will ensure EDCs recover precisely 100% of their administrative expenses from participants. Staff therefore believes that EDCs should collect a set application fee from participants that helps defray program administrative costs, while recovering the balance of those administrative costs from other ratepayers who benefit from Block 1.

Staff also declines to adopt DRC's recommendation to assign Block 1 costs solely to new data centers and other incremental large loads because Block 1 capacity is intended to serve existing load. To be clear, Staff agrees with the larger principle that new large loads should be responsible for paying for the incremental costs of the new capacity needed to serve them. This is why the Board plans to adopt a mechanism in the proceeding implementing the Data Center Fair Share

Act that will incentive data centers to procure and fully pay for VPP portfolios that include BTM energy storage and other DERs that can offset some or all of their load. However, such a mechanism will be separate from and additional to the Block 1 program.

Staff also does not recommend differentiated cost allocation by rate class in this initial block; the Order evaluates costs and benefits at the program and portfolio level while recognizing that Block 1's direct capacity benefits are expected to accrue primarily through the BGS-RSCP class and that broader transmission and distribution benefits may accrue across classes. As described in the Order, costs will be recovered through the applicable EDC RGGI Rider component approved by the Board to enable adequate tracking of program costs. Finally, with respect to differentiated and distinct incentives as requested by certain commentors that would be in proportion to each benefit stream, Staff notes that benefits were estimated using simplifying assumptions appropriate to a BCA. However, the goal of the BCA and Block 1 is to provide a total maximum incentive level, not identified specific cost allocations based on anticipated values and as such, Staff does not recommend distinct incentives tied to wholesale market savings and distribution system benefits.

For the reasons provided in Staff's response to comments in the Eligibility section, Staff recommends against including municipal utilities in the Block 1 program.

## 12. Interconnection

**Summary of Comments:** - Stakeholders addressed whether existing BTM interconnection processes require modification and how exporting, non-exporting, and export-limited storage configurations should be reviewed and accommodated.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G

ACE recommended several changes to support timely BTM interconnection as Block 1 increases residential-storage application volumes. It requested clarified interconnection timelines, scalable staffing and systems, recovery of incremental interconnection labor, and sufficient implementation flexibility to account for feeder conditions and application volumes. ACE also recommended consistent statewide requirements for export-limited systems, including evaluation based on certified export capability rather than nameplate capacity, standardized certification and verification of export-limiting devices, documentation from aggregators and OEMs, and notice of configuration or firmware changes affecting export

behavior. ACE nevertheless recommended leveraging existing interconnection processes during Block 1 rather than establishing an entirely new interconnection architecture.

PSE&G identified existing NEM rules and the absence of a generally available export tariff, other than for larger Qualifying Facilities, as potential barriers to customers realizing the full value of their batteries. ACE contemplated both export-capable and export-limited configurations and recommended evaluating each system according to its certified operating limits. PSE&G emphasized the need for greater clarity regarding customers' ability to export stored energy.

**ii. DRC**

DRC recommended allocating interconnection-related costs according to cost causation. It proposed reasonable interconnection and project-specific technical-review fees for costs directly attributable to an applicant, aggregator, or project, while allowing broader recovery only for common costs supported by demonstrated systemwide benefits.

DRC also recommended requiring each EDC to inventory its existing interconnection systems before proposing new investments and to identify the incremental Block 1 function, lower-cost alternatives, program-specific usage, and other proceedings through which the investment may be funded.

DRC's interconnection recommendations focused principally on cost recognition and allocation. It recommended including every incremental interconnection study and upgrade cost necessary for Block 1 in the BCA and testing those costs through sensitivity analysis. It also recommended applying cost-causation principles so that project-specific technical reviews, interconnection studies, upgrades, and other directly assignable costs may be recovered through reasonable fees from the applicant, participant, aggregator, or project causing them, rather than automatically socialized across nonparticipants. Common interconnection costs could receive broader recovery where an EDC demonstrates corresponding systemwide benefits and an adequate cost-causation basis.

DRC further recommended requiring each EDC to inventory its existing interconnection systems and identify the incremental function, lower-cost alternatives, Block 1 usage, and funding source associated with any proposed new interconnection platform, interface, staffing request, or expenditure. Costs already recovered through base rates or another proceeding should not be recovered again, while genuine incremental Block 1 costs should not be omitted from the BCA merely because an EDC

proposes to recover them elsewhere. DRC also cautioned that EDCs should not use control over interconnection, dispatch information, or system-need data to disadvantage third-party aggregators or steer customers toward utility-affiliated solutions. These recommendations provide cost and nondiscrimination safeguards but do not constitute a proposal to revise the technical interconnection process.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: Coalition; Every Electric Inc.; Koolbridge Energy; Lunar Energy; Nexamp; Outlast Power; RExChain; Uplight; BTM Coalition (Sunrun) – Thad Culley

The technology-sector commenters generally supported interconnection pathways that reflect the actual operating characteristics of participating systems, although they differed regarding whether export should be required. The BTM Coalition recommended that EDCs revise their interconnection materials so standalone and solar-paired batteries can indicate an intention to export under GSESP, coordinate interconnection and program enrollment where practicable, and streamline duplicative application documents. BTM Coalition (Sunrun) – Thad Culley likewise stated that currently net-metered solar-plus-storage systems should be permitted to export. Outlast Power supported expedited and consistent review of certified no-export and limited-export systems, published application checklists and enforceable timelines, and studies based on approved operating limits. Koolbridge Energy supported the Straw Proposal's existing direction to evaluate export-limited systems according to agreed export capability rather than nameplate capacity.

Every Electric alone proposed an alternative compliance pathway for portable, non-exporting plug-in storage. It described AC-coupled batteries that connect through standard receptacles, discharge only to onsite load, and require no permanent installation or conventional interconnection. Every Electric recommended allowing a Board-approved participant certification of non-export, supported by device-level telemetry, to satisfy the interconnection-related Development Maturity requirement without entering the conventional interconnection queue. For performance verification, it proposed telemetry provided through a Licensed Aggregator and validated against whole-premise AMI interval data, which it asserted would support participation by renters and multifamily residents. The BTM Coalition and Lunar Energy supported export-capable solar-plus-storage systems and requested clarification that Dispatch Event exports would not jeopardize NEM eligibility. RExChain requested a determination of whether dispatch-related exports are permitted, required, or excluded and how they

interact with NEM. Every Electric and Outlast Power supported eligibility for non-exporting systems capable of providing verifiable load reductions, while Uplight recommended recognizing both reductions in customer net load and incremental exports at the customer meter.
Although the question posed concerns the existing BTM process, Nexamp separately identified FTM interconnection readiness as a related deployment issue. Nexamp recommended that EDCs begin accepting and processing distribution-connected FTM storage applications before the applicable program opens, establish standardized storage-specific application and study procedures, consider charging schedules and operating constraints, provide project-specific upgrade-cost and schedule information, enforce processing timelines, and treat hosting-capacity maps as preliminary screening tools rather than substitutes for project-specific studies.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties; MSSIA; New Jersey Clean Capacity Coalition; New Jersey Clean Energy Ventures; Vote Solar

The trade associations generally recommended changes or clarifications to facilitate export-capable BTM storage while accommodating limited- and non-export configurations. Advanced Energy United and the Joint Clean Energy Parties recommended expressly authorizing Block 1 batteries to export and requiring EDCs to identify and implement necessary tariff, application, document, and process changes. Advanced Energy United requests clarity on the ability of solar-plus storage systems to export and generate NEM credits. The Joint Clean Energy Parties also recommended protecting the NEM status of existing solar customers that add storage. Clean Peak Energy Group proposed an expedited pathway for qualifying residential and other storage systems of 25 kW or less, including standardized applications and technical documentation, approval within ten business days for complete applications satisfying established screens, no individualized engineering study where those screens are met, and evaluation based on maximum permitted export rather than nameplate capacity. Vote Solar likewise supported studying systems according to agreed export capability and maintaining eligibility for NEM customers, while also emphasizing that non-exporting batteries can provide distribution benefits and should be able to transition to exporting configurations under future flexible or phased interconnection tariffs.

Several trade associations also raised related FTM interconnection issues. The Joint Clean Energy Parties and the New Jersey Clean Capacity Coalition recommended that EDCs begin accepting and studying distribution-connected FTM storage applications before the applicable program opens, develop standardized storage-specific study assumptions and application requirements, and evaluate projects according to enforceable charging, export, limited-export, and dispatch parameters. The Joint Clean Energy Parties additionally recommended allowing projects to adopt controlled- or limited-export configurations without withdrawing and reapplying when the modification would not cause a material adverse system impact. The New Jersey Clean Capacity Coalition proposed an Interconnection Workgroup to address application procedures, site-control requirements, operational study assumptions, cost sharing for utility-side upgrades, and integration of PSUP information into hosting-capacity maps. MSSIA similarly emphasized the need to accelerate FTM interconnection, while New Jersey Clean Energy Ventures recommended prioritizing storage added to existing renewable-generation facilities where existing sites, permits, infrastructure, and unused interconnection capacity could reduce development barriers.

**v. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: Cammie Croft; New Jersey Environmental Justice Alliance

Cammie Croft focused on adapting interconnection-readiness requirements for community-benefit portfolios. She recommended allowing qualified community-benefit participants to obtain a portfolio reservation based on a deployment plan, with site-specific interconnection applications due by a specified milestone, such as six months after the reservation award, and an 18-month deadline for achieving commercial operation instead of the proposed 12-month deadline. She also recommended prioritizing EDC-identified constrained circuits and requiring reporting on interconnection-processing times. Her proposal would modify when community-benefit projects must demonstrate site-specific interconnection readiness rather than revise the underlying technical study standards.

The New Jersey Environmental Justice Alliance recommended incorporating equity requirements directly into interconnection administration. It proposed prioritizing interconnection requests from overburdened communities, using interconnection timelines as a quantitative utility-performance metric, waiving application and study fees for qualifying small storage projects in specified low-income areas, and establishing an Interconnection Ombudsperson office within the BPU Division of DRC, staffed with multilingual customer advocates, to assist

customers with eligibility and interconnection procedures. Neither Cammie Croft nor the New Jersey Environmental Justice Alliance recommended whether participating systems should generally be configured as exporting or non-exporting.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power; Michael Winka

Base Power supported the Straw Proposal's application of N.J.A.C. 14:8-5 to standalone storage, standardized protocols and timelines, evaluation of export-limited systems at their agreed export level, and prohibition of extraneous studies. It recommended expressly extending those protections to all residential BTM storage systems regardless of GSESP enrollment, incentive eligibility, or whether the customer takes service from a third-party supplier. Base Power generally envisioned export-capable systems and recommended that EDC tariffs facilitate grid injection, that AMI interval data register and settle exports as well as consumption, and that exporting batteries be eligible for negative PLC treatment whether or not the host customer participates in NEM.

Michael Winka recommended using the MFR process and PSUP information to identify areas where projected growth exceeds existing hosting capacity. He proposed testing enhanced locational storage incentives in those areas to evaluate whether storage can defer distribution upgrades and expand hosting capacity for solar and electric vehicles.

**Board Staff Response:**

Staff recommends requiring the EDCs to process BTM energy storage interconnection from prospective Block 1 resources pursuant to the Board's existing interconnection rules set forth at N.J.A.C. 14:8-5.1 through N.J.A.C. 14:8-5.13, with the clarification that for the purposes of Block 1 any requirement applicable to a "customer-generator" should be read as applying to an interconnection customer seeking to interconnect a BTM energy storage device, regardless of whether it is standalone storage or part of a solar-plus-storage system. Furthermore, as discussed in the body of the Order, Staff recommends requiring EDCs to allow both standalone BTM energy storage systems and the storage component of solar-plus-storage systems to export to the grid. Staff also recommends allowing existing BTM standalone storage and solar-plus-storage systems to obtain permission to export by submitting new interconnection requests. Staff further recommends that EDCs expedite requests to enable export from the storage component of solar-plus-storage resources if the requestor proposes to

not increase their currently approved export capacity, including by waiving the requirement for an interconnection study unless the EDC has specific reliability concerns about not performing such studies.

As discussed in the Staff response to comments in the NEM section, exports from solar-plus-storage systems will be eligible to receive NEM credit so long as the storage component operates in a "NEM integrity" mode that ensures any energy the storage component exports to the grid was sourced from onsite solar generation. However, the only compensation for exports to the grid from standalone storage systems shall be the Block 1 incentive. To the extent EDC tariff revisions are needed to implement these clarifications, they must do so within 60 days of the effective date of the Order.

Staff believes these recommended clarifications address most of the commenters' requests for clarity on how the interconnection process for Block 1 resources will operate, as well as the numerous requests to allow BTM energy storage devices to export power to the grid. As the Board's existing interconnection rules already provide a pathway for studying DERs at an export capacity that is less than their nameplate capacity if they employ exporting limiting technology, this approach also implements ACE's recommendation to provide a consistent state-wide approach to evaluating Block 1 interconnection requests on the basis of their export capacity. It also implements ACE's recommendation to use existing interconnection processes rather than create a new, bespoke process for Block 1. The sole exception to this is the directive to provide an expedited review pathway for existing solar-plus-storage systems that seek to export from their storage component without increasing their overall export capacity, which Staff believes is a limited and reasonable accommodation to a specific situation that should cause little to no impact on the grid, as the system in question would necessarily already have been fully studied at the requested export level under the Board's generally applicable interconnection rules.

Staff believes the interconnection process for prospective Block 1 participants should be the same as for customer-generators under N.J.A.C. 14:8-5 in the interests of simplicity and standardization. Notably, this means that any prospective Block 1 participants will be responsible for covering the cost of any system upgrades needed to facilitate their interconnection, which aligns with DRC's recommendation that Block 1 interconnection costs should generally be allocated to participants. Staff, however, declines to adopt DRC's other cost allocation recommendations to the extent they are inconsistent with the approach taken in N.J.A.C. 14:8-5. For the same reason, Staff declines to adopt some commenter's recommendations to incorporate

specific equity, community benefit, or Block 1 specific readiness criteria into the interconnection process that would result in Block 1 resources undergoing a different interconnection process than the one provided for in N.J.A.C. 14:8-5.

Staff also acknowledges the requests that the Board provide a pathway for FTM storage interconnection. Staff agrees with commenters that EDCs should create a pathway that allows FTM storage projects to proceed through interconnection review in parallel to the development of the future tariffs and/or program rules that will govern FTM charging rates and discharge compensation. However, Staff believes FTM storage interconnection raises issues that are beyond the scope of the present Order, such as what assumptions EDCs should use regarding the timing of FTM storage charging and discharging, which could have material impacts on FTM interconnection costs. Thus, at this time Staff recommends that the Board not take substantive action on this issue, but instead direct Staff to develop recommended guidance on how to apply the Board's current interconnection rules to FTM storage resources that can be incorporated into a separate Board Order in the near future.

## 13. Overburdened Communities ("OBCs")

**Summary of Comments:** Stakeholders addressed access to storage benefits in OBCs, support for LMI customers and critical facilities, community ownership and resilience, workforce considerations, and mechanisms for addressing existing social and participation gaps.

**i. Utilities**

Commenter(s) Referenced in This Summary: PSE&G; JCP&L; RECO

PSE&G, JCP&L, and RECO identified affordability and access barriers facing LMI and other underserved customers. PSE&G recommended a tailored upfront incentive, an LMI participation sub-target, and flexibility for EDC proposals combining upfront assistance with on-bill repayment; it cited the usage of a sub-target, such as providing income-qualified customers with no-cost batteries in exchange for participation as a potential program model. JCP&L emphasized that upfront costs may remain prohibitive for LMI customers, renters, multifamily residents, and other customers with limited ability to invest in storage and requested greater transparency concerning whether incentive levels can reach those groups. RECO recommended eliminating the $50 application fee because it could unnecessarily discourage low-income residential and smaller commercial customers. None of the utilities proposed an OBC-specific adder or

addressed critical-facility eligibility in this context. ACE and NJNG did not substantively address OBCs, critical facilities, or related participation gaps.

**ii. DRC**

DRC recommended supplementing the BCA with an explicit affordability and bill-impact analysis. It proposed reporting annual and cumulative revenue requirements, cents-per-kWh impacts, and representative monthly bill impacts for residential, small-commercial, large-commercial, and industrial customers, with separate results for participating and nonparticipating customers where applicable. DRC specifically recommended evaluating how program costs may affect less-advantaged and fixed-income households.

DRC also recommended examining the distributional effects of GSESP because program benefits and costs may fall differently across customer groups. It emphasized that a program may reduce overall system costs while still create affordability concerns for particular nonparticipants. DRC therefore supported sensitivity analysis, comparison with reasonably available lower-cost alternatives, and retrospective reporting to determine whether projected savings and customer-bill benefits materialize.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: Bluesky Utility NoFar USA; Every Electric Inc.; Lunar Energy; PowerFlex; RExChain; Voltus; Xura

The technology-sector commenters proposed several different approaches to closing participation and resilience gaps. Every Electric recommended a non-exporting plug-in pathway for renters and multifamily residents and consideration of a reserved portion of each EDC allocation for systems requiring no permanent landlord-approved alteration. Bluesky Utility NoFar USA requested clarification concerning whether a multifamily property could establish a separate EV-charging and battery service and participate despite being placed on a nonresidential tariff. Lunar Energy recommended targeted incentive adders for LMI or equity-focused communities, while Xura supported the proposed OBC adder, recommended extending it to qualifying commercial and EV-charging sites serving OBCs, and pointed to a potential reservation of at least one-quarter of customer-sited incentives for LMI customers and OBCs. Xura also supported allowing critical facilities to retain a backup-energy reserve. RExChain recommended including small-commercial community institutions, such as schools, houses of worship, health facilities, and municipal buildings, because they can provide community resilience beyond that of individual residential systems. PowerFlex and Voltus cautioned against limiting a future C&I block to

critical facilities; Voltus additionally explained that islanding and critical-load support increase project and interconnection costs, meaning a critical-facilities-only program could require higher incentives while excluding lower-cost C&I resources capable of providing broader grid benefits.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Joint Clean Energy Parties; MSSIA; Public Power Association of New Jersey; Vote Solar

The trade associations generally supported targeted mechanisms to broaden storage access and improve community resilience. Vote Solar recommended upfront hardware incentives specifically supporting OBC deployment, OBC identifiers in DER registries, collection and comparison of participation and performance data for OBC- and non-OBC-sited resources, and monitoring of equitable participation. It also proposed a subscription-based community-storage model, including storage paired with community solar, to extend bill savings and grid-service benefits to renters, multifamily residents, LMI subscribers, and customers unable to host DERs. The Joint Clean Energy Parties emphasized that incentive levels must support actual deployment if the Board intends to reach LMI and disadvantaged communities rather than merely improve the economics of systems customers would otherwise purchase. MSSIA identified BTM storage and microgrids as potential sources of resilient power for critical community facilities and OBCs, while also cautioning that critical facilities represent only part of the larger C&I opportunity. The Public Power Association of New Jersey recommended municipal and cooperative participation in part because locally deployed storage could provide resilience to communities and critical facilities and extend program benefits beyond investor-owned EDC territories.

**v. Environmental, consumer, and environmental justice organizations**

Commenter(s) Referenced in This Summary: Cammie Croft; New Jersey Environmental Justice Alliance

Cammie Croft proposed a community-benefit reserve within each EDC allocation, with the reserve size determined by Staff. Eligibility would include a binding LMI participation floor for households at or below 80% of area median income, an additional affordability band extending to 150%, self-attestation and categorical eligibility, and access for renters and multifamily residents. Qualified community-benefit participants could receive portfolio reservations based on deployment plans, followed by site-specific interconnection milestones and an extended commercial-operation period. Croft also recommended a host-benefit standard requiring

protections such as no upfront cost, backup power, no household debt or clawback, a defined share of program value, and plain-language disclosure. Unused reserved capacity would revert to the general queue, reporting would identify participation by income band, municipality, and housing type, and oversubscription would trigger a subsequent residential block sized to the waitlist. She further proposed prorating or capping reservations during the capacity-exhaustion week to prevent one portfolio from receiving an EDC's remaining allocation.

NJEJA proposed a binding equity framework centered on community ownership, revenue allocation, and community governance. Its recommendations included a 25% community-ownership requirement in each EDC territory, a phased procurement set-aside for OBC-based community aggregators, a 50% customer pass-through floor, a 25% OBC revenue-flow requirement, and a 10% incentive multiplier for resources in high-energy-burden census blocks. NJEJA proposed directing the OBC revenue share into an OBC Resilience Fund governed by a majority-OBC board and used for energy-efficiency improvements, community microgrids, workforce development, and emergency-preparedness infrastructure for medically vulnerable households. It also recommended quarterly equity reporting, performance-linked clawbacks, fee waivers for qualifying small projects, OBC and ownership tagging in the DER registry, multilingual outreach, extended comment periods, an Interconnection Ombudsperson, and a Community Advisory Board with authority over specified eligibility, emergency-dispatch, fund-allocation, and material program-modification decisions.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Mary Ellen Hennessy-Jones; Peter Fried; Syntropic Capital Partners

Syntropic Capital Partners recommended separately modeling-owned, debt-financed systems and authorizing on-bill repayment to expand storage access for LMI households unable to purchase systems outright. Mary Ellen Hennessy-Jones and Peter Fried recommended including municipal electric utilities because municipal storage could lower power-supply costs, improve reliability, and provide resilience for local communities and critical facilities. Fried additionally maintained that excluding municipal systems could deny storage benefits to communities with limited financial and operational resources.

**Board Staff Response:**

Staff does not recommend binding OBC or LMI capacity set-asides, incentive multipliers, community-ownership mandates, or advisory-board approval authority for the initial block. Environmental, consumer, and environmental-justice commenters proposed a range of targeted mechanisms to address affordability, resilience, renter and multifamily access, community ownership, and historical underinvestment, while other stakeholders emphasized broad customer access, manageable program cost, and a simple initial structure. Staff agrees that equitable access and the distribution of program benefits must be evaluated, but the record does not establish a single implementable mechanism, funding level, eligibility rule, or administrative structure that can be adopted without materially increasing initial program cost and complexity.

Staff is also concerned that mechanisms like LMI or OBC carve-outs, adders, or multipliers could perversely have regressive effects that end up harming other LMI and/or OBC customers. Staff's preliminary analysis indicates that achieving the carve-out targets some commenters suggest would require very significant increases to the base incentives Staff recommends. Such enhanced incentives may materially exceed the value the incentivized energy storage systems would provide to the grid. That in turn would mean such mechanisms could come at a significant net cost to other ratepayers. Because higher electricity costs tend to disproportionately burden LMI and OBC customers, Staff is concerned that such mechanisms may actually *worsen* equity outcomes unless they are funded from a non-ratepayer source. Staff notes that they could well be exceptions, such as when the projects in question provide significant community resilience or distribution-level benefits (which are heavily discounted in the Block 1 BCA given its lack of locational targeting). However, determining which specific LMI or OBC projects fit that criteria would take substantial additional analysis and is not possible to do unless Staff significantly delays the launch of Block 1. Such a delay would also harm LMI and OBC customers by delaying the arrival of the electricity price relief Block 1 can provide to all ratepayers.

Nonetheless, Staff stresses that identifying ways to cost-effectively target the provision of greater benefits to LMI customers and OBCs is already an objective for future blocks. Staff simply believes the Board needs more data and more analysis to ensure any future program design benefits LMI customers and OBCs as a whole, rather than benefit just a small subset of them at the expense of other LMI customers and/or OBCs.

Each EDC filing must therefore describe its outreach, education, marketing, enrollment, and customer-support strategies; identify known participation barriers; and explain how those strategies will reach diverse audiences, as required by the MFRs. Annual reporting must provide the participation and program data needed to assess whether the general design is reaching OBC and LMI customers and whether targeted measures are warranted. This approach is sufficient for the initial block because it requires affirmative access planning and creates an evidentiary record without reserving scarce capacity or increasing incentives before Staff can determine which intervention would be effective and cost justified. Any later set-aside, multiplier, community-benefit standard, or governance requirement will require prospective Board action.

As indicated above, Staff shares Rate Counsel's concern about the potential distributional impacts of the Block 1 program. This is part of why Staff has recommended an incentive level that provides a high all-ratepayer BCR even under fairly conservative BCA assumptions (see Staff's response to comments in the Benefit Cost Methodology section for further discussion on this point). That conscious design decision inherently reduces the risk that the Block 1 program will result in a lifetime increase to costs for LMI customers or particularly vulnerable groups of ratepayers. Still, Staff agrees that design decision is not a sufficient safeguard by itself given potential variation in the ratio of benefits to costs among different customer classes. This is why Staff has recommended that the MFRs require the EDCs to perform bill impact analyses by customer class for each year of their proposed Block 1 programs before the Board provides final approval for each EDC's program design.

As explained in Staff's response to comments in the Eligibility section, Staff believes that municipal utility participation is incompatible with the design of the Block 1 program. Staff therefore disagrees with the commenters arguing that the Block 1 program should provide a pathway for municipal utility participation. Nonetheless, as also noted in the response to comments in the Eligibility section, Staff is open to allowing municipal utility participation in future blocks or storage programs.

Finally, Staff notes that small-commercial community institutions may be eligible for Block 1 as long as they are on a BGS-RSCP rate.

# 14. Interoperability with Other VPP Programs

**Summary of Comments:** Stakeholders addressed coordination among GSESP, the VPP Interim Program, and future Grid Flexibility Services through aligned eligibility, telemetry, dispatch, cybersecurity, EM&V, migration, and value-stacking requirements.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G; JCP&L; RECO; NJNG

The utilities generally supported coordinating Block 1 with the future VPP/Grid Flexibility Services framework, although they proposed different structural approaches. ACE envisioned GSESP as the near-term BTM deployment mechanism and VPP/GridFlex as the longer-term grid-services compensation framework, supported by common registration, telemetry, cybersecurity, dispatch, EM&V, and settlement requirements that would allow resources to transition without new hardware or duplicative onboarding. PSE&G recommended consolidating the initiatives into a single BTM program architecture, while JCP&L requested a roadmap addressing eligibility, compensation, dispatch rights, interoperability, transitions, and multiple value streams before substantial technology investments are made. RECO favored flexible requirements that use aggregators and its existing demand-response platform, and NJNG supported coordination among storage, energy-efficiency, VPP, and other Board programs.

On value stacking, ACE, JCP&L, and NJNG generally supported compensation for distinct, measurable services while preventing payment twice for the same performance or system benefit. ACE recommended common baselines, clear attribution of each service, service-specific compensation, and an established dispatch hierarchy; JCP&L similarly requested duplicate-compensation controls and rules governing participation in multiple value streams. NJNG raised whether separately incentivized fuel cells and batteries could later be aggregated and compensated through a VPP, recommending clear cross-program rules where the services are distinct and separately measured. PSE&G and RECO did not propose detailed value-stacking methodologies.

**ii. DRC**

DRC emphasized that Block 1 should not be evaluated as a standalone program because its ten-year commitments may overlap with a future open-access VPP tariff, demand-response programs, Triennium initiatives, other DER programs, wholesale markets, and the same utility systems and claimed benefits. It recommended establishing coordinated planning,

operations, accounting, and cost-effectiveness frameworks before creating long-term compensation rights that could overlap. DRC did not mention GridFlex or Grid Flexibility Services by name, but its comments directly address coordination between GSESP Phase 2 and the future VPP framework.

DRC recommended establishing and disclosing transition rules before Block 1 enrollment. The rules should explain whether a participant transitioning to a future VPP permanently relinquishes its remaining GSESP payments and whether previously paid amounts must be reconciled when the associated future obligation will no longer be provided. They should also address removal from Block 1 capacity accounting, eligibility to reenter Block 1, and responsibility for duplicative acquisition, enrollment, integration, metering, and administrative costs. DRC recommended designing Block 1 without assuming that a future VPP tariff or additional VPP compensation will become available and informing participants of the transition consequences before they make a ten-year commitment.

DRC recommended that the Board establish functional requirements addressing dispatch timing, reliability, telemetry, verification, cybersecurity, and override authority. It also supported aggregator-mediated dispatch through standardized signals, auditable device-level data, and consideration of whether the selected architecture can support multiple future DER programs. DRC recommended maximizing existing AMI, demand-response, manufacturer, aggregator, data, and utility capabilities before authorizing new platforms. All genuinely incremental transition and integration costs should be included in the BCA.

For compensation, DRC recommended one ratepayer-funded pathway by default and proposed establishing a resource-level registry and compensation ledger before enrollment. The ledger would record GSESP incentives, VPP and demand-response payments, and EDC and Triennium support. It would also capture solar, EV, and resilience incentives, federal and State tax-supported assistance, tariff savings, aggregator payments, and wholesale energy, capacity, and ancillary-service revenues. For each payment, the ledger would identify the obligation purchased and the period during which that obligation applies.

DRC explained that the resource-level ledger would be used to evaluate participation in multiple services rather than automatically prohibit it. Each claimed service should be incremental, separately measurable, operationally compatible, and worth more to ratepayers than the combined

compensation paid to procure it. Where cross-program participation is permitted, overlapping public or ratepayer-funded compensation should be offset dollar-for-dollar, and total ratepayer-funded support should not exceed the participating resource's verified incremental value. The same kW of discharge should not be credited simultaneously to multiple programs unless each program purchases a distinct obligation and the combined compensation remains below the verified value delivered.

DRC further recommended tracking VPP and wholesale revenues that arise after Block 1 enrollment to determine whether they reduce the economic gap supporting the GSESP incentive. Future values that are not independently measurable or are operationally incompatible with Block 1 dispatch obligations should not be stacked merely because they carry a different program label. DRC separately stated that a properly approved Block 1 contract should not be retroactively altered merely because market conditions later change. Read together, its comments support establishing stacking, offset, transition, and reconciliation rules before enrollment and using later revenue and performance data to inform future incentive levels, rather than imposing unannounced retroactive changes.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; EnergyHub; Koolbridge Energy; Lunar Energy; Mainstay Energy; RExChain; Solar Landscape; Uplight; Voltus

These commenters generally recommended that Block 1 use open, scalable, and technology-neutral systems that can support subsequent VPP participation without separate integrations or incompatible operating requirements. Uplight proposed using the same Edge DERMS/VPP architecture for registration, availability, forecasting, dispatch, telemetry, M&V, settlement, event rules, and performance compensation from the outset. Lunar Energy recommended making outcome-based VPP readiness an eligibility condition, including an open third-party dispatch and state-of-charge interface and interval telemetry sufficient for M&V and PJM settlement, while encouraging—but not prescribing—a single protocol stack. RExChain supported common statewide OpenADR dispatch signals, event schemas, and settlement formats; Koolbridge Energy and Mainstay Energy likewise supported open, interoperable interfaces rather than proprietary control platforms. The BTM Coalition and EnergyHub recommended relying on existing OEM, aggregator, device-telemetry, and Edge DERMS capabilities and avoiding duplicative licensing or operating structures.

These commenters generally supported value stacking when each payment corresponds to a distinct service, coupled with service-level controls against double counting. Voltus recommended separating generation, transmission, and distribution capacity value, preserving PJM generation-capacity participation while using GSESP to compensate distribution and non-emergency transmission services; it proposed a one-for-one performance offset where PJM and GSESP compensate the same dispatch hour and a reversible election between programs. Solar Landscape similarly recommended adjusting or excluding compensation for benefits already monetized while retaining eligibility for separately measurable distribution, reliability, capacity, renewable-generation, VPP, GridFlex, or PJM services. Uplight, EnergyHub, and RExChain likewise favored identifying duplication at the service or value-stream level rather than categorically excluding a resource based on its program, supplier, or rate. Lunar Energy additionally requested that resources transitioning out of Block 1 retain previously earned incentives.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties; New Jersey Clean Capacity Coalition; New Jersey Clean Energy Ventures; Vote Solar

The trade associations generally recommended coordinating GSESP with the VPP and GridFlex frameworks rather than creating disconnected participation pathways. Advanced Energy United recommended coordinated treatment of existing and new batteries to avoid a fragmented market. The Joint Clean Energy Parties (“JCEP”) recommended an open aggregator/OEM control model under which EDCs would transmit standardized dispatch instructions and authorized platforms would execute them. JCEP also recommended standardized device-level interval telemetry, consistent statewide communications requirements, open and interoperable protocols where practicable, and a common statewide settlement and verification methodology to support eventual migration into the broader VPP/GridFlex framework. Clean Peak Energy Group (“CPEG”) favored technology-neutral functional requirements for interoperability, telemetry, response, M&V, availability, data security, and cybersecurity. Vote Solar recommended carrying GSESP device-level measurement into the Interim and Long-Term VPP Programs. The New Jersey Clean Capacity Coalition (“NJCCC”) proposed a staged plan for distribution-connected FOM storage and GridFlex, including an independent value-stack study in Q3 2026, revised VPP guidance for existing BESS in Q4 2026, a comprehensive GridFlex Order and MFRs covering BTM and FOM resources in Q3 2027, tariff approval in Q1 2028, program launch in Q3

2028, and initial project operation by Q2 2029. NJCCC also recommended a transparent GridFlex process open to broader stakeholder participation. New Jersey Clean Energy Ventures recommended allowing near-term FOM development to proceed while the longer-term framework is completed.

Trade associations addressing value stacking generally supported compensation for distinct services while preventing duplicate payment for the same value. In the context of a third-party-supplier pathway, Advanced Energy United recommended assessing double counting according to the service being compensated rather than the channel through which a resource participates. CPEG recommended allowing participating resources to retain and monetize legitimate value streams before relying on larger direct subsidies. It specifically proposed recognizing negative capacity and transmission peak contributions and evaluating transparently valued Coincident Peak Performance and Locational Distribution Value adders. JCEP recommended a publicly funded independent value-stack study and gap analysis, supported by open technical sessions and stakeholder review, to identify realizable benefits, the remaining project revenue gap, and the services ready for implementation. It also recommended that GridFlex define how projects participate in PJM markets or operate as load reducers and prevent unjustified compensation without unnecessarily prohibiting legitimate revenue stacking. NJCCC supported operational flexibility for FOM resources to combine wholesale revenues, including ancillary-service and energy-arbitrage revenues, with distribution-grid services, subject to clear performance standards.

**v. Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft; Climate Jobs NJ; New Jersey Environmental Justice Alliance

These commenters supported cross-program compatibility but proposed different levels of prescription. Climate Jobs NJ recommended limiting GSESP incentives to resources built to standards that ensure future VPP interoperability. Cammie Croft recommended carrying device-level telemetry and settlement rules into the VPP tariff so a resource transitioning from Block 1 does not encounter a second measurement regime. The New Jersey Environmental Justice Alliance recommended harmonized technical standards across GSESP, VPP, PSUP, and related proceedings, including a unified DER registry and requirements allowing resources to transition without duplicative interconnection reviews, conflicting telemetry specifications, or separate hardware installations.

Cammie Croft recommended applying anti-duplication rules at the level of the service, performance obligation, and interval. Under her proposal, the same capacity, transmission, distribution, or performance obligation during the same interval would not receive multiple payments, while wholesale energy, ancillary services, performance outside GSESP events, and other distinct obligations could be compensated separately. NJEJA proposed a more restrictive PJM safeguard under which a GSESP resource would either forgo PJM capacity-market participation or accept a one-for-one reduction in its PJM capacity credit equal to the megawatt-hours dispatched during GSESP events. NJEJA also recommended quarterly reporting that separates GSESP incentives, capacity-market revenues, and ancillary-service compensation, supported by standardized registry data and clawback provisions where duplicate compensation occurs.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power; Michael Winka

Base Power recommended a unified accounting and operating framework serving Block 1, the VPP Interim Program, third-party-supplier VPPs, and related demand-reduction programs. It proposed preserving a resource's interconnection status and DER registry record when it transitions, allowing participants to change aggregators or suppliers without losing their Awarded Storage Capacity, and treating Block 1 data and telemetry as sufficient for future VPP participation without re-registration. Base Power also recommended uniform statewide technical certification and recognition of a future Board-issued DER Aggregator license for Block 1 purposes. Michael Winka viewed GSESP as the foundation for a broader DSO/VPP market and recommended using the interim period to test additional distribution-grid services, metering approaches, and dispatch models before establishing the permanent framework.

Base Power supported stacking compensation for distinct services by assigning each value stream to a single compensation pathway. For third-party-supplier customers already capturing wholesale capacity or transmission value, it recommended a reduced distribution-only GSESP payment tied to the distribution share of the Board's cost-benefit analysis, thereby preserving compensation for incremental distribution services without paying twice for wholesale value. It also recommended allowing opt-out without clawing back previously earned incentives. Michael Winka supported developing broader market-based compensation for storage services over time and recommended phasing down or sunsetting incentives as those services become independently economic and compensated through the future DSO/VPP market.

**Board Staff Response:**

Staff recommends interoperability principles and enforceable anti-duplication controls to the extent practicable in Block 1, while reserving detailed future value-stacking and licensing rules for later Board action as these efforts cannot be quantified or described until future subsequent proceedings. For the immediate PowerUp NJ programs, this means a Block 1 storage device cannot simultaneously participate in and receive compensation from the VPP Interim program. Each EDC filing must describe the contractual, enrollment, data, and systems controls used to identify existing obligations and prevent simultaneous enrollment, counting, and payment.

DRC emphasized that a ratepayer-funded resource should have one compensation pathway by default and that any additional payment must purchase a distinct, separately measurable, operationally compatible service rather than the same capacity, availability, dispatch, or interval performance. Staff supports and recommends this approach for the PowerUp NJ Program immediate program offerings of GSESP Block 1 and VPP Interim Program. As future VPP and grid services structures evolve, it is Staff's intention to enforce prohibitions on duplicate compensation for identical services, preserve auditable evidence of resource obligations, and allow future stacking only where a later Board-approved framework defines the distinct service and associated measurement.

Staff declines to recommend the Board establish a detailed DER Registry, Aggregator Registry, licensing, or value-stacking rules in this Order, though Staff agrees with DRC that such mechanisms will be highly useful or outright needed in the future. First, Block 1's single program participation model along with its anti-duplicate compensation rules and prohibition on wholesale market participation obviate the need for such mechanism in the short-term. Second, Staff believes that properly designing these mechanisms will require significant and time-intensive design work, along with further stakeholder engagement. Insisting that this all occur prior to the launch of Block 1 would materially and needlessly delays its launch. Thus, Staff recommends the Board proceed to launch Block 1 while the development of such mechanisms proceeds in parallel.

Staff supports the clarity sought by DRC and other stakeholders regarding a transitional framework between future programs, while also acknowledging that the absence of those program design structures presently limits the level of detail with which transitional rules can be established. More formal transition provisions can be developed as those programs are implemented and their respective design

parameters become defined. While it is both plausible and desirable that Block 1 resources be eligible to provide and be compensated for distinct services under future compensation frameworks, it is also possible that some resources may elect to transition fully from Block 1 into a successor program. In such circumstances, a Block 1 participant would forfeit any remaining Block 1 compensation opportunities, but would not be subject to clawbacks of incentive payments already earned. The resource's MW value should be removed from Block 1 capacity accounting and would be eligible to re-enroll at a future date only to the extent that subsequent incremental block capacity is available. Where full transitional disenrollment is not required and simultaneous program participation is permitted, Block 1 resources would remain subject to all applicable Block 1 program requirements, including, but not limited to, restrictions on participation as supply-side resources in PJM wholesale markets and any other structure that would impede a resource from operating as reasonably expected by the program.

## 15. EDC Control of Storage Systems

**Summary of Comments:** Stakeholders addressed the benefits and drawbacks of EDC-directed dispatch or direct device control, the appropriate role of third-party control platforms, and the allocation of operational authority, reliability responsibility, and customer control.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G; JCP&L; RECO

The utilities generally supported EDC authority to identify system needs, determine when and where resources should be dispatched, resolve conflicting dispatch signals, and intervene when necessary to preserve distribution-system reliability, although they differed regarding routine direct device control. PSE&G and RECO expressed the strongest support for EDC operational authority: PSE&G recommended giving EDCs priority to dispatch, curtail, prevent, or reverse dispatch based on real-time system conditions, while RECO supported allowing EDCs to direct, control, and dispatch participating resources for system peaks, local constraints, and reliability needs. ACE supported utility-directed dispatch coordination and oversight but recommended that aggregators, OEMs, and third-party platforms ordinarily execute device-level commands; it identified improved alignment with local reliability needs and reduced dispatch conflicts as benefits, while cautioning that prescriptive utility-control requirements could increase integration costs and delay implementation. JCP&L similarly

supported EDC reliability overrides, operational visibility, telemetry access, and performance-validation rights while allowing third parties to manage devices, provided that responsibility, authority, and liability correspond to the party exercising actual control.

**ii. DRC**

DRC supported EDC-directed dispatch to the extent necessary to ensure that ratepayer-funded resources are available at the time and location of an identified system need. It also supported allowing EDCs to retain operational discretion to call Dispatch Events within uniform Board-established parameters based on local system conditions. DRC distinguished that operational authority from direct control of individual batteries and stated that direct EDC device control should not be presumed to be the only or least-cost implementation model.

DRC recommended comparing at least three approaches: direct EDC control, aggregator-mediated dispatch through standardized EDC signals, and tariff- or price-based response where the desired system behavior can be obtained without a separate control platform. The comparison should consider incremental technology costs, cybersecurity, communications reliability, latency, customer opt-out rights, measurement accuracy, vendor lock-in, and the ability to support multiple future DER programs. DRC did not categorically oppose direct EDC control; an EDC could propose that model if it demonstrates that the architecture satisfies the required functions at the lowest reasonable cost.

DRC identified reliable availability at the time and location of system need and preservation of EDC operational authority as potential benefits of EDC-directed dispatch. It identified unnecessary technology costs, duplicative customer-device control systems, vendor lock-in, interference with customer opt-out rights, and potential discrimination against third-party aggregators as risks of presuming direct EDC control. DRC explained that aggregators may be capable of reliably executing standardized EDC dispatch instructions through their own device-management platforms, preserving EDC operational authority while avoiding the need for every EDC to build a separate device-control system and potentially providing a broader selection of services through a more competitive platform.

DRC recommended that the Board establish functional requirements for dispatch timing, reliability, telemetry, verification, cybersecurity, and override rules, while requiring each EDC to justify the least-cost architecture meeting those requirements. Any EDC override authority should be narrow, documented, and auditable. DRC also cautioned that

EDCs should not use control over interconnection, dispatch information, or system-need data to disadvantage third-party aggregators or steer customers toward utility-affiliated solutions.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; EnergyHub; Koolbridge Energy; Lunar Energy; PowerFlex; Prologis; RExChain; Solar Landscape; Uplight; Voltus; Xura

These commenters generally distinguished EDC authority to call Dispatch Events from direct EDC control of individual batteries. The BTM Coalition, EnergyHub, Koolbridge Energy, Lunar Energy, PowerFlex, RExChain, Uplight, and Voltus recommended that EDCs identify the grid need and communicate event instructions while aggregators, OEMs, participants, or Edge DERMS platforms determine how individual resources respond. They reasoned that third-party platforms already possess the necessary device integrations, customer relationships, state-of-charge information, backup-reserve settings, and fleet-optimization capabilities. They also argued that direct EDC control could duplicate existing systems, increase administrative and technology costs, narrow device eligibility and customer choice, expand cybersecurity and communications risks, delay implementation, interfere with customer uses and other value streams, and separate performance responsibility from the party bearing the financial consequences of underperformance.

Several commenters recognized circumstances in which stronger EDC authority could be appropriate. RExChain supported a narrowly defined and subsequently reported direct-control override for bona fide reliability emergencies, while Xura supported EDC dispatch authority bounded by published event limits, advance-notice requirements, and customer backup reserves. Prologis proposed an optional direct-control arrangement with an enhanced incentive where an EDC requires greater operational certainty. Solar Landscape recommended distinguishing an EDC's enforceable authority to call a contracted grid service from direct device-level control. It supported EDC responsibility for identifying system needs and calling Dispatch Events, but recommended requiring direct control only where necessary to provide the applicable service reliably or maximize ratepayer value, rather than where an OEM, aggregator, or resource owner can satisfy the applicable response-time, telemetry, M&V, cybersecurity, and reliability standards. For FTM storage, Solar Landscape was open to reserving capacity for EDC use, granting significant dispatch rights, or allowing more direct control to address identified distribution or reliability needs. It recommended pairing those commitments with fixed or otherwise

predictable multi-year compensation, with additional performance-based compensation where appropriate, that reflects committed capacity and availability, charging and cycling costs, degradation and performance obligations, lost operating flexibility, and foregone outside revenues. Solar Landscape also recommended statewide principles governing dispatch rights, availability, performance, compensation, and direct control, with materially different requirements among EDC territories justified by demonstrated system needs.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Advanced Energy United; Clean Peak Energy Group; Joint Clean Energy Parties; New Jersey Clean Capacity Coalition; New Jersey Clean Energy Ventures; Public Power Association of New Jersey; Vote Solar

Trade associations addressing this topic generally supported EDC authority to identify system needs and call Dispatch Events while favoring execution through qualified third-party platforms rather than routine direct EDC device control. Advanced Energy United recommended retaining the Straw Proposal's event-based model, under which EDCs call events and participants respond under established terms. Clean Peak Energy Group recommended allowing third-party owners and aggregators to execute EDC instructions through qualified existing control platforms that satisfy interoperability, telemetry, response-time, M&V, availability, data-security, and cybersecurity requirements. The Joint Clean Energy Parties similarly recommended an aggregator/OEM-based model, citing the risk that direct utility control would duplicate existing capabilities, require unnecessary communications and control-system investment, create additional cybersecurity and operational obligations, and produce inconsistent EDC-specific requirements and additional ratepayer costs. New Jersey Clean Energy Ventures recommended that the EDC identify the system need, call the event, and transmit the dispatch instruction, while the project owner, aggregator, or OEM executes deployment and provides the data needed to verify performance and administer payments. Vote Solar expressly recognized that direct EDC control could provide more consistent dispatch and closer alignment with distribution-system needs, but recommended prioritizing third-party control in Block 1 because direct control could increase administrative burdens and costs, diminish customer autonomy, concentrate performance risk with the EDCs, and shift that risk to ratepayers.

The New Jersey Clean Capacity Coalition recommended self-directed dispatch for FTM resources, reasoning that owners and operators are

better positioned to optimize wholesale and distribution value streams and should retain control because they bear the financial consequences of performance. It recommended using clear operating and performance standards instead of mandatory EDC control. The Public Power Association of New Jersey separately emphasized that investor-owned EDCs should not dispatch resources interconnected to municipal or cooperative systems, instead suggesting that the applicable municipal utility or cooperative should retain operational authority and call-hour control while complying with comparable statewide performance requirements.

**v. Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft

Cammie Croft recommended retaining a bounded and reported emergency override because direct EDC control can provide greater certainty during a local emergency. For other events, she recommended that EDCs transmit dispatch signals for execution by participants or Aggregators, with performance verified using the same interval data used for settlement. She stated that this model would provide an auditable basis for performance verification, avoid the consent and cost problems associated with utility control of household devices, and avoid duplicative utility control infrastructure consistent with Staff's expectation that a new DERMS is not required for Block 1.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power; Ecological Systems LLC; Mary Ellen Hennessy-Jones; Michael Winka; Peter Fried

Base Power opposed direct device-level EDC control and recommended fleet-level dispatch in which EDCs specify the event window, location, and requested capacity while Participants operate their portfolios and retain device-level data for audit. It argued that direct EDC control would duplicate existing fleet-management systems, require additional utility technology investment, complicate management of state of charge, customer backup reserves, and wholesale-market participation, and shift operational responsibility without transferring the participant's performance risk. Ecological Systems LLC advocated an autonomous distribution-level control model in place of centralized command-and-control. Its proposed Clean Peaker Parity Tariff would rely on UL 1741 SB-compliant smart inverters to respond locally to circuit conditions without awaiting external commands from an EDC or aggregator, with inverter logs and AMI data supporting measurement and settlement. Michael Winka supported EDC

control in a mature DSO/VPP market but recommended maximum flexibility during the interim program until rules distinguish when storage is available for grid dispatch and when customers retain it for BTM use, cautioning that overly specific requirements could reduce participation and cost-effectiveness. Mary Ellen Hennessy-Jones and Peter Fried focused on municipal and cooperative systems, recommending that the applicable municipal utility or cooperative retain dispatch authority and call-hour control over resources interconnected to its distribution system rather than being subject to investor-owned EDC control.

**Board Staff Response:**

Staff recommends a signal-and-settle model rather than routine direct EDC control of individual storage devices, subject to limited EDC override authority when necessary to ensure the safe and reliable operation of their distribution systems. Staff believes comments from multiple stakeholder perspectives support this approach. Specifically, the EDCs generally supported retaining authority to identify grid needs, call events, validate performance, and protect reliability, and both ACE and JCP&L agreed these objectives could be accomplished without direct EDC control of devices apart from limited override authority to ensure grid reliability. Technology providers, aggregators, trade associations, environmental and consumer commenters, and other market participants generally favored execution through DER Providers, OEMs, or qualified third-party platforms that already manage device state of charge, customer backup reserves, and portfolio performance. DRC similarly supported EDC-directed dispatch where needed to obtain the ratepayer-funded service but cautioned that direct EDC device control should be presumed to be the only or least-cost method.

Under the adopted model, the EDC issues the event signal and retains bounded override authority necessary for local reliability while the participant executes dispatch and remains accountable for verified performance. Each EDC filing must specify interfaces, latency, acknowledgment and failure procedures, override rights, customer opt-outs, cybersecurity, liability allocation, audit rights, performance accountability, and incremental costs. This structure is sufficient because it preserves EDC reliability authority and auditable settlement while placing operational responsibility with the entity controlling the device and bearing performance risk, thereby avoiding duplicative utility control infrastructure.

# 16. Alternative Dispatch, M&V

**Summary of Comments:** Stakeholders addressed whether alternative metering, communications, dispatch-control, and M&V arrangements could provide reliable performance verification and greater ratepayer savings than the proposed performance-based incentive framework.

**i. Utilities**

Commenter(s) Referenced in This Summary: ACE; PSE&G; JCP&L; RECO

The utilities generally favored a phased implementation that uses existing metering, communications, and dispatch capabilities where practicable while evaluating additional capabilities according to their costs, functions, and long-term scalability. ACE recommended allowing EDCs to use existing AMI, utility systems, aggregator and OEM platforms, and Grid-Edge DERMS capabilities, cautioning that a prescribed statewide architecture could strand existing investments, increase costs, and delay implementation. ACE also noted that grid-injecting configurations may require additional device-level or power-quality metering. RECO stated that alternative metering and dispatch control systems should not replace the proposed performance-based incentive framework. Instead, RECO recommended retaining customer incentives as the principal participation mechanism while treating enhanced metering and dispatch capabilities as complementary tools for improving program administration and operational performance. It recommended flexible requirements coordinated with the final Block 1 and VPP designs, anticipated using a third-party aggregator together with its existing Demand Response Management System, and proposed allowing these capabilities to evolve based on GSESP and Interim VPP experience, with associated implementation costs included in program administration. PSE&G requested clarification regarding what constitutes an alternative metering or dispatch-control system and recommended cost-benefit review before requiring capabilities beyond those supported by existing residential AMI. JCP&L emphasized using existing capabilities where practical while ensuring EDC access to real-time and historical telemetry, independent data-validation and auditing rights, and scalable technology that supports future VPP and grid-flexibility integration without creating duplicative or stranded investments.

**ii. DRC**

DRC recommended that the EDCs evaluate available metering and dispatch architectures using cost-benefit analysis principles. It identified three architectures for comparison: direct EDC control, aggregator-

mediated dispatch using standardized signals, and tariff- or price-based response where the desired system behavior can be obtained without a separate control platform. DRC recommended comparing incremental technology costs, cybersecurity, communications reliability and latency, customer opt-out rights, measurement accuracy, vendor lock-in, and the ability to support multiple future DER programs.

DRC further recommended that each EDC inventory its existing AMI, demand-response, customer-data, communications, DERMS, interconnection, and aggregator-interface capabilities before proposing new investments.

**iii. Technology providers, aggregators, developers, and OEMs**

Commenter(s) Referenced in This Summary: BTM Coalition; EnergyHub; Every Electric; Koolbridge Energy; Lunar Energy; PowerFlex; Prologis; RExChain; Solar Landscape; Uplight; WeaveGrid

Most technology providers supported retaining the performance-based incentive framework while improving the data, dispatch, and verification architecture used to implement it. The BTM Coalition, EnergyHub, Lunar Energy, PowerFlex, Prologis, RExChain, and Solar Landscape generally supported compensating verified performance rather than substituting capacity-only or deemed-savings payments. The BTM Coalition and EnergyHub recommended accepting existing manufacturer or aggregator device telemetry as the default performance-data source, reasoning that separate utility meters would add cost and delay without materially improving accuracy. Every Electric proposed device telemetry submitted through an Aggregator and verified against AMI whole-premise interval data, particularly for plug-in systems in rental and multifamily properties. Prologis similarly supported EMS or AMI data for portfolio settlement, while RExChain recommended embedded inverter and battery-management telemetry, an established accuracy standard, annual third-party attestation, and selective EDC field verification instead of dedicated revenue-grade meters. EnergyHub and PowerFlex also recommended calculating compensation using average verified output rather than the minimum-interval methodology.

Other commenters proposed more integrated enhancements. Koolbridge Energy recommended a technology-neutral evidence chain separately recording the EDC request, device command and acknowledgment, accepted commitment, achieved device response, export, customer override, communications fallback behavior, and utility-meter result, using existing telemetry wherever practicable. Uplight recommended a common

Edge DERMS/VPP platform for forecasting, availability, dispatch, and settlement, with device telemetry supporting operations and AMI data plus an appropriate baseline determining the incremental change in customer net load or export. It argued that this would better establish whether battery operation produced an actual grid benefit and enable locational dispatch. WeaveGrid similarly recommended feeder-, transformer-, and substation-level mapping and distribution-aware orchestration so dispatch addresses specific constraints and avoids creating localized grid stress. Solar Landscape supported the proposed residential approach but recommended considering stronger EDC dispatch rights and more predictable compensation for future FTM resources where increased operational control can produce additional system value.

**iv. Trade associations**

Commenter(s) Referenced in This Summary: Clean Peak Energy Group; Joint Clean Energy Parties; MSSIA; New Jersey Clean Capacity Coalition; New Jersey Clean Energy Ventures; Vote Solar

Most trade associations supported preserving performance-based compensation while relying on existing third-party platforms and standardized data rather than new proprietary utility systems. The Joint Clean Energy Parties recommended that EDCs transmit standardized instructions to aggregators, OEMs, or approved control platforms, with performance verified through standardized device-level interval telemetry and a common statewide settlement and verification methodology. Clean Peak Energy Group similarly recommended qualified existing control platforms, interval-data verification, and functional requirements for interoperability, telemetry, response time, M&V, availability, data security, and cybersecurity. Vote Solar considered the proposed device-level system sufficient and recommended extending that measurement approach across other BPU programs. The New Jersey Clean Capacity Coalition considered inverter telemetry and device-level measurement sufficiently robust and auditable to avoid the need for a utility-operated Grid DERMS in the short term, while New Jersey Clean Energy Ventures supported EDC event instructions executed by owners, aggregators, or OEMs with performance data returned to the EDC for verification and settlement.

MSSIA proposed a materially different structure for larger BTM and FTM resources: a fixed annual payment based on energy-storage capacity over approximately ten to fifteen years, subject to a minimum performance requirement initially focused on PJM capacity performance and subsequently transmission and distribution services. MSSIA reasoned that this simpler structure could be implemented more quickly and provide

greater investment certainty while allowing private owners and aggregators to compete in peak forecasting and dispatch. It recommended adding more complex distribution services as the market and operating framework mature rather than delaying deployment until every metering and control issue is resolved.

**v. Environmental, consumer, and environmental justice organizations**
Commenter(s) Referenced in This Summary: Cammie Croft

Cammie Croft recommended using device-level measurement as the basis for performance verification and settlement, with EDC dispatch instructions executed by the participant or Aggregator. She stated that this structure would provide an auditable performance record while avoiding duplicative utility-control infrastructure and remaining consistent with Staff's expectation that a new DERMS is not required for Block 1. Croft recommended evaluating any additional metering or control architecture according to whether its incremental ratepayer savings exceed its implementation, communications, and administrative costs.

**vi. Program implementers, consultants, and academic commenters**
Commenter(s) Referenced in This Summary: Base Power; Ecological Systems LLC; Michael Winka

Base Power supported performance-based compensation but recommended fleet-level integration, dispatch, and evaluation for participants operating their own platforms. Under its proposal, an EDC would issue one portfolio-level dispatch instruction, the participant would operate the enrolled fleet, and portfolio interval data would remain resolvable to individual devices for audit. Base Power argued that individual EDC integration with every battery would duplicate existing control layers and add cost without improving verification. Ecological Systems LLC proposed a more decentralized Clean Peaker Parity Tariff under which smart inverters would respond autonomously to local grid conditions and existing AMI would support measurement and settlement, reducing reliance on centralized command-and-control infrastructure. Michael Winka recommended keeping the initial performance-incentive structure simple while allowing EDCs to test alternative metering and dispatch approaches, such as IEEE 2030-related systems, time-of-use rates, and additional grid-service applications, in limited sandbox areas during the interim VPP period before incorporating them into the permanent framework.

**Board Staff Response:**

Staff recommends retaining performance-based compensation supported by device-level measurement and auditable interval data, while allowing EDCs to use the least-cost architecture that satisfies the MFRs' functional requirements. Technology providers, trade associations, and other market participants proposed a range of alternatives using AMI, OEM telemetry, Edge DERMS platforms, portfolio-level dispatch, or other third-party tools; DRC emphasized that any selected architecture must be auditable, avoid duplicate recovery, and be compared with lower-cost existing capabilities.

The Order therefore does not mandate a single technology vendor or new utility platform. An EDC may use existing AMI, OEM data, or a qualified third-party platform if the approach provides dispatch confirmation, accurate Performance Interval data, validation, cybersecurity, settlement, auditability, and data retention. Consequently, each filing must identify the required function, existing capability, proposed integration, alternatives considered, incremental cost, allocation method, and recovery source.

Staff agrees with DRC's general point that EDCs should compare the costs and benefits of different implementation approach and selecting the one that presents the highest net benefits. However, in the interests of speed, simplicity, and avoiding the need for major new capital expenditure on the part of EDCs, the Board is directing EDCs to implement a DER Provider-mediated dispatch model, not a direct EDC control model or a tariff or price-based response model. Staff therefore believes EDCs should not be required to evaluate the costs and benefits of those latter two approaches. Rather, EDCs should only assess the costs and benefits of implementation strategies they have the discretion to use.

Staff believes this approach allows EDCs to assess and the Board to review various potentially lower-cost and competitive solutions before the Board provides final approval to EDC program designs. At the same time, it preserves a common program framework and consistent statewide measurement approach. This gives the EDCs sufficient direction to narrow the scope of their design while avoiding overly prescriptive architecture requirements that could needlessly increase the cost of program implementation.

Staff does not recommend delaying Block 1 for a separate alternative-control pilot or requiring an independent evaluator as that would also delay the ratepayer savings Block 1 is expected to provide. Staff notes that the Board may modify requirements prospectively if verified operating evidence demonstrates that another approach provides greater ratepayer savings or equivalent performance at lower cost.

# Attachment E

In the Matter of Establishing the PowerUp New Jersey Program, Docket No. QO26100658

In the Matter of Advancing a Virtual Power Plant (VPP) Program in the State of New Jersey Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program – Phase 2 Distributed Storage, Docket No. QO26040116

Annual incentive payments will be determined using the following structure:

**(1) Annual Incentive Payment =**

**(Incentive Rate, $/kW/year) × (Awarded Storage Capacity, kW) × (Performance Factor, %)**

**(2) Performance Factor =** $\frac{\frac{\sum_{i=1}^{D} Dispatch\ Event\ Min\ Output_i}{D}}{Awarded\ Storage\ Capacity}$

Where:

- **Incentive Rate ($/kW/year)** is the administratively determined maximum incentive rate.
- **Awarded Storage Capacity (kW)** means the nameplate power output of an energy storage system measured in kilowatts of alternating current (kW AC or kW), that is eligible to be dispatched and used for calculation of incentive payments.
- **Dispatch Event Min Output (kW)** for a given Dispatch Event, *i*, is the average discharge during the performance interval with the lowest average discharge of any performance interval during the relevant dispatch event. For example, if a dispatch event has three performance intervals and average discharge during the first performance interval is 5 kW, the average discharge during the second performance interval is 4 kW, and the average discharge during the third performance interval is 3 kW, the Dispatch EventMin Output for that dispatch event would be 3 kW. Dispatch Event Minimum Output may equal but not exceed Awarded Storage Capacity.
- **Performance Interval (kW)** is a one-hour period over which measured output is averaged. There can be as many as three (3) Performance Intervals in each Dispatch Event. The Performance Intervals associated with a given Dispatch Event are set 21 hours in advance, begin at the start time of Dispatch Event, and last exactly 1 hour, meaning that duration of Dispatch Events can only be integer values of 1, 2 or 3.,
- **D (count)** is the number of Dispatch Events called in a year, not to exceed 35.

- **Average Min Discharge (kW):** means the sum of the Dispatch Event Min Output in a performance year divided by the number of dispatch events called in a performance year.

An illustrative calculation for a theoretical 10 kW/15 kWh battery is shown in Table 1 below.

**Table 1. Example Incentive Calculation**

| Item | Metric | Assumption Source | Value |
|---|---|---|---|
| | | *Program Inputs* | |
| (a) | Incentive Rate ($/kW) | Rate | $200 |
| (b) | Power Capacity (kW) | Assumption | 10 kW |
| (c) | Energy Capacity (kWh) | Assumption | 15 kWh |
| (d) | Awarded Storage Capacity (kW) | (b) | 10 kW |
| | | *Example* | |
| (e) | Dispatch Events | Assumption (EDC-dependent) | 30 |
| (f) | Average Dispatch Event Duration | Assumption (EDC-dependent) | 2.5 hr |
| (g) | Performance Intervals | (e) * (f) | 75 |
| (h) | Average Min Discharge | Assumption (considers 20% OEM holdback) | 4.8 kW |
| (i) | Performance Factor | (h) / (d) | 48% |
| (j) | Annual Incentive Payment | (a) * (d) * (i) | $960 |

# Attachment F

In the Matter of Establishing the PowerUp New Jersey ("PowerUp NJ") Programs

Docket No. QO26100658

In the Matter of Advancing a Virtual Power Plant ("VPP") Program in the State of New Jersey

Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program ("GSESP") Pursuant to P.L. 2018, c. 17

Docket No. QO22080540

## COST TEST METHODOLOGIES AND ASSUMPTIONS FOR THE VIRTUAL POWER PLANT INTERIM PROGRAM

This Attachment describes the benefit-cost analysis methodology and assumptions the Virtual Power Plant ("VPP") Interim Program, a sub-program of the PowerUp NJ Program established by the Order to which this Attachment is appended (the "Order"). Six (6) benefit-cost tests are required under Attachment A, Section V(a): the Ratepayer Impact Measure ("RIM"), New Jersey Cost Test ("NJCT"), Total Resource Cost ("TRC") test, Societal Cost Test ("SCT"), Program Administrator Cost Test ("PACT"), and Participant Cost Test ("PCT"). RIM is the primary test. Each electric distribution company ("EDC" or "utility") shall apply them in the benefit-cost analysis required by Section V of Attachment A ("VPP Interim MFR"). Where this Attachment prescribes a methodology or a fixed assumption (such as the peak shaving target, performance factor, event limits, benefit timing, and adders), the utility shall use it. Where the last column of a table is marked "Y," the utility may propose a different value with justification, as Attachment A, Section V(d) provides. For any line item this Attachment does not address, the utility shall propose the methodology and unit value it will apply. "Performance year" has the meaning given in Attachment A: October 1 through September 30, except that the first performance year begins on the date the first VPP Interim sub-program becomes operational, and the last performance year ends September 30, 2029.

Avoided energy, ancillary service, and emission values, and the conversion of nominal dollars to real dollars, follow the New Jersey Cost Test methodology and data sources the Board adopted for the second triennium of energy efficiency programs ("T2 Order").[1] The utility shall derive its

[1] In re the Implementation of P.L. 2018, c. 17, The New Jersey Clean Energy Act of 2018, Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs; In re the Implementation of P.L. 2018, c. 17, the New Jersey Clean Energy Act of 2018, Regarding the Second Triennium of Energy Efficiency and Peak Demand Reduction Programs; In re Electric Public Utilities and Gas Public Utilities Offering Energy Efficiency and Conservation Programs, Investing in Class I Renewable Energy Resources and Offering Class I Renewable Energy Programs in Their Respective Service Territories on a Regulated Basis, Pursuant to N.J.S.A. 48:3-98.1 and N.J.S.A. 48:3-87.9 – Minimum Filing Requirements, BPU Docket Nos. QO19010040, QO23030150, and QO17091004, Order Directing the Utilities to Propose Second Triennium Energy Efficiency and Peak Demand Reduction Programs, dated July 26, 2023.

own values using that methodology and those data sources. Its values may therefore differ from the examples in this Attachment.

Values marked "Example" show how each calculation works. They are not fixed values. Many inputs change each year, including, but not limited to, energy and ancillary service prices, Network Service Peak Load ("NSPL"), five coincident peak load ("5CP"), transmission ("NITS") rates, capacity auction ("BRA") prices, the Forecast Pool Requirement ("FPR"), load growth, marginal distribution capacity ("MDC") cost, marginal emission rates, avoided damage values, and the GDP chain-type price index. For each of these inputs, the utility shall use the most recent value available at the time of its filing from PJM, the U.S. Energy Information Administration ("EIA"), the U.S. Environmental Protection Agency, its own planning data, or another credible source, and shall cite the source and date of each value.

The utility shall calculate each test over the two performance years (Year 1 and Year 2) and discount Year 2 values to Year 1. As the NJCT methodology in the T2 Order provides[2], the NJCT and SCT use a 3% real discount rate; the RIM, TRC, PACT and PCT use a 7% nominal discount rate; real values are converted from nominal dollars with the most recent GDP chain-type price index forecast in the EIA Annual Energy Outlook.

## I. Ratepayer Impact Measure (RIM) – VPP Interim

### a. Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | **Calculation**<br>= (1) NSPL MW × (2) Peak Shaving Target % × (3) Load Growth Factor × (4) Performance Factor % × (5) Dispatch Hours × (6) Energy Price $/MWh<br>1) NSPL by EDC, the most recent values PJM publishes. Example (2026 NSPL): PSE&G 10,229.5 MW; ACE 2,709.1 MW; JCP&L 6,273.4 MW; RECO 422.9 MW.<br>2) 3% peak shaving target, the minimum target as the Order sets<br>3) EDC-specific annual peak load growth %, from the utility's most recent load forecast, applied as (1 + growth %)^(t − 1), where t is the performance year (Year 1 = no growth). Example: 1% per year<br>4) 67% performance factor: MW delivered ÷ MW committed across PJM's Summer 2025 demand response events. Applies to every avoided-cost benefit line item. | **N** |

[2] In re the Implementation of P.L. 2018, c. 17, The New Jersey Clean Energy Act of 2018, Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs; In re the Implementation of P.L. 2018, c. 17, the New Jersey Clean Energy Act of 2018, Regarding the Second Triennium of Energy Efficiency and Peak Demand Reduction Programs; In re Electric Public Utilities and Gas Public Utilities Offering Energy Efficiency and Conservation Programs, Investing in Class I Renewable Energy Resources and Offering Class I Renewable Energy Programs in Their Respective Service Territories on a Regulated Basis, Pursuant to N.J.S.A. 48:3-98.1 and N.J.S.A. 48:3-87.9 – Minimum Filing Requirements, BPU Docket Nos. QO19010040, QO23030150, and QO17091004, Order Directing the Utilities to Propose Second Triennium Energy Efficiency and Peak Demand Reduction Programs, dated July 26, 2023.

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| | | 5) 35 events per year × 3 hours, the event limits in the Order<br>6) Summer on-peak wholesale energy price, derived under the NJCT methodology in the T2 Order (PJM day-ahead locational marginal prices, escalated with the EIA Annual Energy Outlook), for the calendar year that holds the performance year's summer months (June – September). Example: $33.75/MWh (Year 1, 2028); $34.00/MWh (Year 2, 2029)<br><br>**Benefit Realized Timing**<br>Year 1: 0%. Year 2: 33%.<br>Most residential and small commercial customers buy power at fixed Basic Generation Service ("BGS-RSCP") prices. BGS supply is bought in three (3) annual tranches, so savings reach customers only as tranches are repriced.<br><br>**Source**<br>PJM, Network Service Peak Loads for 2026; PJM, Load Management Event Performance (Summer 2025), DISRS, Nov. 3, 2025; T2 Order (NJCT methodology); EIA, Annual Energy Outlook. | |
| B2 | Avoided wholesale electric ancillary services | **Calculation**<br>= (1) NSPL MW × (2) Peak Shaving Target % × (3) Load Growth Factor × (4) Performance Factor % × (5) Dispatch Hours × (6) Ancillary Price $/MWh<br>1) Same as B1 input (1)<br>2) Same as B1 input (2)<br>3) Same as B1 input (3)<br>4) Same as B1 input (4)<br>5) Same as B1 input (5). B1 and B2 use the same dispatched MWh.<br>6) Ancillary services price, derived under the NJCT methodology in the T2 Order (three-year rolling average of PJM ancillary service prices from the Independent Market Monitor's State of the Market Report, escalated at the same rate as energy), same calendar-year basis as B1. Example: $1.08/MWh (Year 1, 2028); $1.09/MWh (Year 2, 2029)<br><br>**Benefit Realized Timing**<br>Same as B1.<br><br>**Source**<br>T2 Order (NJCT methodology); Monitoring Analytics (PJM Independent Market Monitor), State of the Market Report for PJM. | **N** |
| B3 | Avoided wholesale electric capacity | **Calculation**<br>= (1) 5CP MW × (2) Peak Shaving Target % × (3) Load Growth Factor × (4) Performance Factor % × (5) Forecast | **N** |

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| | | Pool Requirement × (6) BRA Price $/MW-day × (7) BGS Gross-Up × (8) Days<br>1) Weather-normalized load at PJM's five (5) summer coincident peaks (5CP) by EDC, the most recent values PJM publishes. Example (Summer 2025): PSE&G 9,770 MW; ACE 2,227.5 MW (AECO zone, excluding Vineland's 87.5 MW); JCP&L 5,760 MW; RECO 390 MW<br>2)–4) Same as B1<br>5) Forecast Pool Requirement ("FPR") PJM publishes for the delivery year. FPR = (1 + installed reserve margin) × average accreditation factor. It converts MW of peak load into the MW of capacity that load must buy. Example (DY 2028/29): 0.9401 = (1 + 20%) × 0.7834<br>6) Base Residual Auction ("BRA") clearing price for the delivery year, the most recent value PJM publishes, held flat. Example: $325/MW-day, the 2028/2029 BRA clearing price (at the price cap)<br>7) 15% gross-up to translate wholesale capacity cost to BGS<br>8) 365 days in DY 2028/29<br><br>**Benefit Realized Timing**<br>• PJM recognizes the load reduction through a Peak Shaving Adjustment ("PSA") Plan. The utility files the plan with PJM by the required deadline, as required in Attachment A. The first delivery year it can lower is DY 2028/29.<br>• Delivery years run June 1 to May 31. Performance years run October 1 to September 30, so each performance year spans two delivery years.<br>• Year 1 (October 2027 – September 2028): 0%. Eight (8) of its twelve (12) months fall in Delivery Year (DY) 2027/2028. Capacity obligations for that delivery year are set before the program launches.<br>• Year 2 (October 2028 – September 2029): 33% of the full DY 2028/29 value. Only the BGS-RSCP tranche bought in February 2028 can reflect the lower obligation.<br>• Capacity savings are counted for DY 2028/29 only. The tranche bought in February 2028 is a three-year contract, so customers may see this saving spread from June 2028 through May 2031. This Attachment counts the 33% in Year 2 for simplicity, although four (4) months of DY 2028/29 (June – September 2028) fall in Year 1. Peak shaving in summer 2029 may also lower the DY 2029/30 obligation. Four (4) months of DY 2029/30 (June – September 2029) fall in Year 2, but this Attachment does not count any DY 2029/30 savins. These simplifications may understate benefits, which may keep the test conservative. | |

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| | | **Source**<br>PJM, Summer 2025 Weather Normalized RTO Coincident Peaks and 5CPs (rev. Nov. 14, 2025); PJM, 2028/2029 BRA FPR and IRM, MRC, Feb. 19, 2026; PJM, 2028/2029 BRA Results Report; PJM Manual 19, Attachment D. | |
| B4 | Avoided electric transmission | **Calculation**<br>= (1) NSPL MW × (2) Peak Shaving Target % × (3) Load Growth Factor × (4) Performance Factor % × 1,000 × (5) NITS Rate $/kW-yr × (6) Escalation Factor<br>1)–4) Same as B1<br>5) PJM Network Integration Transmission Service ("NITS") rate for each EDC zone, the most recent values PJM publishes. Example (as of Jan. 1, 2025): PSE&G $176.71; ACE $103.40; JCP&L $39.84; RECO $53.77 per kW-yr<br>6) 2.5% per year, applied as 1.025^(t−1), where t is the performance year<br><br>**Benefit Realized Timing**<br>Year 1: 0%. Year 2: 33%. Same BGS delay and timing convention as B3.<br><br>**Source**<br>PJM, Annual Transmission Revenue Requirements and NITS Rates, as of Jan. 1, 2025. | **N** |
| B5 | Avoided electric distribution | **Calculation**<br>= (1) 5CP MW × (2) Peak Shaving Target % × (3) Load Growth Factor × 1,000 × (4) Marginal Distribution Capacity Cost $/kW-yr × (5) Escalation Factor × (6) Deferral Hit Rate % × (7) Performance Factor %<br>1) Same as B3 input (1)<br>2) Same as B1 input (2)<br>3) Same as B1 input (3)<br>4) Marginal distribution capacity cost ("MDC"), based on the utility's own distribution planning data, with justification and citation. Example: $25/kW-yr<br>5) 2% per year, applied as (1 + 2%)^(t − 1), where t is the performance year<br>6) 25% deferral hit rate: the share of enrolled kW on circuits where an upgrade is actually deferred<br>7) Same as B1 input (4)<br><br>**Benefit Realized Timing**<br>Year 1: 100%. Year 2: 100%. | **Y** |
| B6 | Electric energy DRIPE | **Calculation**<br>= B1 Avoided wholesale electric energy × 5%<br><br>**Methodology Discussion**<br>• Demand reduction induced price effect ("DRIPE"): lower demand lowers wholesale energy prices for all load. | **N** |

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| | | The 5% adder is the same treatment used for energy efficiency programs.<br>• Benefit realized timing: same as B1.<br><br>**Source**<br>T2 Order (NJCT methodology). | |
| B7 | Electric capacity DRIPE | Zero. | **N** |
| B13 | Participant incentive received | Same as C1 Participant incentive payments. | **N** |

### b. Costs

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C1 | Participant incentive payments | **Calculation**<br>= (1) Program Budget $ × (2) Incentive Share % × (3) Share of Budget Spent in Year %<br>1) The two-year program budget for each utility: PSE&G $50,000,000; JCP&L $25,000,000; ACE $22,000,000; RECO $3,000,000.<br>2) 80% incentives (20% administration)<br>3) 50% in Year 1; 50% in Year 2<br><br>**Methodology Discussion**<br>• As defined in Attachment A, Section V(e)(i).<br>• Costs are Administrative Expense, recovered in the year incurred with no return. | **Y** |
| C2 | Program administration and implementation costs | **Calculation**<br>= (1) Program Budget $ × (2) Administrative Share % × (3) Share of Budget Spent in Year %<br>1) Same as C1 input (1)<br>2) 20% administration<br>3) Same as C1 input (3)<br><br>**Methodology Discussion**<br>• As defined in Attachment A, Section V(e)(ii). | **Y** |

## II. New Jersey Cost Test (NJCT) – VPP Interim

### a. Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | Same as RIM B1. | **N** |

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B2 | Avoided wholesale electric ancillary services | Same as RIM B2. | **N** |
| B3 | Avoided wholesale electric capacity | Same as RIM B3. | **N** |
| B4 | Avoided electric transmission | Same as RIM B4. | **N** |
| B5 | Avoided electric distribution | Same as RIM B5. | **Y** |
| B6 | Electric energy DRIPE | Same as RIM B6. | **N** |
| B7 | Electric capacity DRIPE | Same as RIM B7. | **N** |
| B8 | Avoided CO2 damages | **Calculation**<br>= (1) MWh Avoided × (2) Marginal CO2 Emission Rate (metric tons/MWh) × (3) Avoided Damage Value $/metric ton<br><br>1) MWh avoided, from B1 (dispatched MWh before the B1 timing factor)<br>2) Marginal CO2 emission rate, derived under the NJCT methodology in the T2 Order, for the same calendar year as B1, converted from lb/MWh to metric tons/MWh (÷ 2,204.62). Example: 792 lb/MWh (Year 1, 2028); 776 lb/MWh (Year 2, 2029)<br>3) Avoided CO2 damage value (social cost of carbon), derived under the NJCT methodology in the T2 Order, in nominal $ per metric ton. Example: $284 (Year 1, 2028); $293 (Year 2, 2029)<br><br>**Benefit Realized Timing**<br>Year 1: 100%. Year 2: 100%. Emissions are avoided when dispatch occurs.<br><br>**Source**<br>T2 Order (NJCT methodology). | **N** |
| B9 | Avoided NOx damages | **Calculation**<br>= (1) MWh Avoided × (2) Marginal NOx Emission Rate (metric tons/MWh) × (3) Avoided Damage Value $/metric ton<br>1) MWh avoided, from B1 (dispatched MWh before the B1 timing factor)<br>2) Marginal NOx emission rate, derived under the NJCT methodology in the T2 Order, for the same calendar year as B1, converted from lb/MWh to metric tons/MWh (÷ 2,204.62). Example: 0.27 lb/MWh (Year 1, 2028); 0.27 lb/MWh (Year 2, 2029)<br>3) Avoided NOx damage value, derived under the NJCT methodology in the T2 Order, in nominal $ per metric ton. Example: $10,006 (Year 1, 2028); $10,302 (Year 2, 2029) | **N** |

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| | | **Benefit Realized Timing**<br>Year 1: 100%. Year 2: 100%. Emissions are avoided when dispatch occurs.<br><br>**Source**<br>T2 Order (NJCT methodology). | |
| B10 | Avoided SO2 damages | **Calculation**<br>= (1) MWh Avoided × (2) Marginal SO2 Emission Rate (metric tons/MWh) × (3) Avoided Damage Value $/metric ton<br>1) MWh avoided, from B1 (dispatched MWh before the B1 timing factor)<br>2) Marginal SO2 emission rate, derived under the NJCT methodology in the T2 Order, for the same calendar year as B1, converted from lb/MWh to metric tons/MWh (÷ 2,204.62). Example: 0.10 lb/MWh (Year 1, 2028); 0.10 lb/MWh (Year 2, 2029)<br>3) Avoided SO2 damage value, derived under the NJCT methodology in the T2 Order, in nominal $ per metric ton. Example: $74,261 (Year 1, 2028); $76,554 (Year 2, 2029)<br><br>**Benefit Realized Timing**<br>Year 1: 100%. Year 2: 100%. Emissions are avoided when dispatch occurs.<br><br>**Source**<br>T2 Order (NJCT methodology). | **N** |
| B11 | Non-energy benefit adder | Zero. | **N** |
| B12 | Low-income adder | Zero. | **N** |

### b. Costs

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C2 | Program administration and implementation costs | Same as RIM C2. | **Y** |
| C6 | Participant incremental cost | Zero.<br><br>**Methodology Discussion**<br>• Enrolled devices are already installed or are funded through other Board-approved programs, as Attachment A, Section V(e)(iii) provides. | **N** |

## III. Total Resource Cost Test (TRC) – VPP Interim

### a. Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | Same as RIM B1. | **N** |
| B2 | Avoided wholesale electric ancillary services | Same as RIM B2. | **N** |
| B3 | Avoided wholesale electric capacity | Same as RIM B3. | **N** |
| B4 | Avoided electric transmission | Same as RIM B4. | **N** |
| B5 | Avoided electric distribution | Same as RIM B5. | **Y** |
| B6 | Electric energy DRIPE | Same as RIM B6. | **N** |
| B7 | Electric capacity DRIPE | Same as RIM B7. | **N** |

### b. Costs

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C2 | Program administration and implementation costs | Same as RIM C2. | **Y** |
| C6 | Participant incremental cost | Same as NJCT C6. | **N** |

## IV. Societal Cost Test (SCT) – VPP Interim

### a. Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | Same as RIM B1. | **N** |
| B2 | Avoided wholesale electric ancillary services | Same as RIM B2. | **N** |
| B3 | Avoided wholesale electric capacity | Same as RIM B3. | **N** |
| B4 | Avoided electric transmission | Same as RIM B4. | **N** |
| B5 | Avoided electric distribution | Same as RIM B5. | **Y** |

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B6 | Electric energy DRIPE | Same as RIM B6. | **N** |
| B7 | Electric capacity DRIPE | Same as RIM B7. | **N** |
| B8 | Avoided CO2 damages | Same as NJCT B8. | **N** |
| B9 | Avoided NOx damages | Same as NJCT B9. | **N** |
| B10 | Avoided SO2 damages | Same as NJCT B10. | **N** |
| B11 | Non-energy benefit adder | Same as NJCT B11. | **N** |
| B12 | Low-income adder | Same as NJCT B12. | **N** |

### b. Costs

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C2 | Program administration and implementation costs | Same as RIM C2. | **Y** |
| C6 | Participant incremental cost | Same as NJCT C6. | **N** |

## V. Program Administrator Cost Test (PACT) – VPP Interim

### a. Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | Same as RIM B1. | **N** |
| B2 | Avoided wholesale electric ancillary services | Same as RIM B2. | **N** |
| B3 | Avoided wholesale electric capacity | Same as RIM B3. | **N** |
| B4 | Avoided electric transmission | Same as RIM B4. | **N** |
| B5 | Avoided electric distribution | Same as RIM B5. | **Y** |
| B6 | Electric energy DRIPE | Same as RIM B6. | **N** |
| B7 | Electric capacity DRIPE | Same as RIM B7. | **N** |

### b. Costs

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C1 | Participant incentive payments | Same as RIM C1. | **Y** |
| C2 | Program administration and implementation costs | Same as RIM C2. | **Y** |

## VI. Participant Cost Test (PCT) – VPP Interim

### a. Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B13 | Participant incentive received | Same as RIM B13. | **N** |
| B14 | Participant bill savings | The utility proposes the methodology and unit value under Attachment A, Section V(d). | **Y** |

### b. Costs

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C6 | Participant incremental cost | Same as NJCT C6. | **N** |

## VII. Example: Ratepayer Impact Measure (RIM) Calculation

This section shows, step by step, how the RIM results below are calculated. The RIM compares the present value of benefits to all ratepayers with the present value of program costs to all ratepayers. A ratio above 1.0 means benefits exceed costs.

The example uses the example values in Sections I through VI and the two-year program budget set for each utility. The example values are illustrations only. Each utility shall use the most recent values available at the time of its filing, with citations and justification, and may propose different values where the tables above permit. Numbers in this section are rounded for display. The ratios are calculated from unrounded values.

**Table VII-1. RIM results from this example**

| Test | PSE&G | JCP&L | ACE | RECO | New Jersey |
|---|---|---|---|---|---|
| RIM (all ratepayers) | 1.26 | 1.12 | 0.997 | 0.995 | 1.16 |

### a. Example Inputs

Table VII-2 lists the utility-specific example inputs. Table VII-3 lists the inputs that are the same for every utility. Year 1 runs from October 1, 2027, through September 30, 2028. Year 2 runs from October 1, 2028, through September 30, 2029.

**Table VII-2. Utility-specific example inputs**

| Input (unit) | PSE&G | JCP&L | ACE | RECO |
|---|---|---|---|---|
| NSPL (MW) — B1, B2, B4 | 10,229.5 | 6,273.4 | 2,709.1 | 422.9 |
| 5CP (MW) — B3, B5 | 9,770.0 | 5,760.0 | 2,227.5 | 390.0 |
| NITS rate ($/kW-yr) — B4 | $176.71 | $39.84 | $103.40 | $53.77 |
| Marginal distribution capacity cost ($/kW-yr) — B5 | $25.00 | $25.00 | $25.00 | $25.00 |
| Program budget, two years ($) — C1, C2 | $50,000,000 | $25,000,000 | $22,000,000 | $3,000,000 |

**Table VII-3. Shared example inputs**

| Input (unit) | Year 1 | Year 2 |
|---|---|---|
| Peak shaving target (% of peak load) | 3% | 3% |
| Load growth factor, 1% per year: (1 + 1%)^(t − 1) | 1.00 | 1.01 |
| Performance factor (%) | 67% | 67% |
| Dispatch hours: 35 events × 3 hours | 105 | 105 |
| Energy price ($/MWh) | $33.75 | $34.00 |
| Ancillary services price ($/MWh) | $1.08 | $1.09 |
| Forecast Pool Requirement | 0.9260 (DY 2027/28) | 0.9401 (DY 2028/29) |
| BRA price ($/MW-day) | $325 | $325 |
| BGS gross-up on capacity | 15% | 15% |
| Days in delivery year | 366 | 365 |
| NITS escalation factor: 1.025^(t − 1) | 1.000 | 1.025 |
| Distribution escalation factor: 1.02^(t − 1) | 1.00 | 1.02 |
| Distribution deferral hit rate (%) | 25% | 25% |
| Energy DRIPE adder (% of B1) | 5% | 5% |
| Benefit timing: B1, B2, B3, B4 (and B6) | 0% | 33% |
| Benefit timing: B5 | 100% | 100% |
| Incentive share / administrative share of budget | 80% / 20% | 80% / 20% |
| Share of budget spent in the year | 50% | 50% |
| RIM discount factor, 7% nominal: 1 ÷ 1.07^(t − 1) | 1.0000 | 0.9346 |

### b. Step 1 – Enrolled Load, Performing Load, and Dispatched Energy

Each utility enrolls 3% of its peak load. Only the performing share (67%) delivers the reduction. For PSE&G:

Enrolled MW, NSPL basis:
10,229.5 MW × 3% × 1.00 = 306.9 MW (Year 1);
10,229.5 MW × 3% × 1.01 = 310.0 MW (Year 2).

Performing MW, NSPL basis:
306.9 MW × 67% = 205.6 MW (Year 1);
310.0 MW × 67% = 207.7 MW (Year 2).

Enrolled MW, 5CP basis:
9,770 MW × 3% × 1.00 = 293.1 MW (Year 1);
9,770 MW × 3% × 1.01 = 296.0 MW (Year 2).

Performing MW, 5CP basis:
293.1 MW × 67% = 196.4 MW (Year 1);
296.0 MW × 67% = 198.3 MW (Year 2).

Dispatched energy:
performing MW (NSPL basis) × 105 hours = 21,589 MWh (Year 1);
performing MW (NSPL basis) × 105 hours = 21,805 MWh (Year 2).

**Table VII-4. Step 1 results for every utility**

| Quantity | PSE&G | JCP&L | ACE | RECO |
|---|---|---|---|---|
| Enrolled MW, NSPL basis, Year 1 | 306.9 | 188.2 | 81.3 | 12.7 |
| Enrolled MW, NSPL basis, Year 2 | 310.0 | 190.1 | 82.1 | 12.8 |
| Performing MW, NSPL basis, Year 1 | 205.6 | 126.1 | 54.5 | 8.5 |
| Performing MW, NSPL basis, Year 2 | 207.7 | 127.4 | 55.0 | 8.6 |
| Enrolled MW, 5CP basis, Year 1 | 293.1 | 172.8 | 66.8 | 11.7 |
| Enrolled MW, 5CP basis, Year 2 | 296.0 | 174.5 | 67.5 | 11.8 |
| Performing MW, 5CP basis, Year 1 | 196.4 | 115.8 | 44.8 | 7.8 |
| Performing MW, 5CP basis, Year 2 | 198.3 | 116.9 | 45.2 | 7.9 |
| Dispatched energy (MWh), Year 1 | 21,589 | 13,240 | 5,718 | 893 |
| Dispatched energy (MWh), Year 2 | 21,805 | 13,372 | 5,775 | 901 |

### c. Step 2 – Annual Benefits (PSE&G)

Each benefit line uses the Step 1 quantities, the example prices, and the benefit timing. In Year 1, energy, ancillary, capacity, and transmission benefits are counted at 0%. In Year 2, they are counted at 33%. Distribution benefits are counted at 100% in both years. In the all-ratepayer RIM, the incentive participants receive (B13) is a benefit, because participants are ratepayers, and the same amount is a cost (C1).

**Table VII-5. Step 2 annual benefits, PSE&G**

| Line | Calculation | Year 1 | Year 2 |
|---|---|---|---|
| B1 Avoided energy | MWh × energy price × timing<br>Y1: 21,589 MWh × $33.75/MWh × 0%<br>Y2: 21,805 MWh × $34.00/MWh × 33% | $0 | $244,655 |
| B2 Avoided ancillary services | MWh × ancillary price × timing<br>Y1: 21,589 MWh × $1.08/MWh × 0%<br>Y2: 21,805 MWh × $1.09/MWh × 33% | $0 | $7,843 |
| B3 Avoided capacity | Performing MW (5CP) × FPR × BRA price × 1.15 × days × timing<br>Y1: 196.4 MW × 0.9260 × $325/MW-day × 1.15 × 366 days × 0%<br>Y2: 198.3 MW × 0.9401 × $325/MW-day × 1.15 × 365 days × 33% | $0 | $8,394,098 |
| B4 Avoided transmission | Performing MW (NSPL) × 1,000 kW/MW × NITS rate × escalation × timing<br>Y1: 205.6 MW × 1,000 × $176.71/kW-yr × 1.000 × 0%<br>Y2: 207.7 MW × 1,000 × $176.71/kW-yr × 1.025 × 33% | $0 | $12,412,829 |
| B5 Avoided distribution | Enrolled MW (5CP) × 1,000 kW/MW × MDC × escalation × hit rate × performance factor × timing<br>Y1: 293.1 MW × 1,000 × $25/kW-yr × 1.00 × 25% × 67% × 100%<br>Y2: 296.0 MW × 1,000 × $25/kW-yr × 1.02 × 25% × 67% × 100% | $1,227,356 | $1,264,422 |
| B6 Energy DRIPE | B1 × 5%<br>Y1: $0 × 5%<br>Y2: $244,655 × 5% | $0 | $12,233 |
| B7 Capacity DRIPE | Zero | $0 | $0 |
| B13 Participant incentive received | Equals C1 (Step 3) | $20,000,000 | $20,000,000 |
| **Total annual benefits** | | **$21,227,356** | **$42,336,081** |

### d. Step 3 – Annual Costs (PSE&G)

**Table VII-6. Step 3 annual costs, PSE&G**

| Line | Calculation | Year 1 | Year 2 |
|---|---|---|---|
| C1 Participant incentive payments | Budget × 80% × 50%; $50,000,000 × 80% × 50% | $20,000,000 | $20,000,000 |
| C2 Program administration | Budget × 20% × 50%; $50,000,000 × 20% × 50% | $5,000,000 | $5,000,000 |
| **Total annual costs** | | **$25,000,000** | **$25,000,000** |

### e. Step 4 – Present Value and RIM Ratio (PSE&G)

The RIM uses a 7% nominal discount rate. Year 1 values are counted as is. Year 2 values are divided by 1.07.

PV of benefits = $21,227,356 + ($42,336,081 ÷ 1.07) = $21,227,356 + $39,566,431 = $60,793,787

PV of costs = $25,000,000 + ($25,000,000 ÷ 1.07) = $25,000,000 + $23,364,486 = $48,364,486

RIM ratio (PSE&G) = **$60,793,787 ÷ $48,364,486 = 1.26**

### f. Step 5 – Results for Every Utility and New Jersey

JCP&L, ACE, and RECO follow the same steps with their own inputs from Table VII-2. The New Jersey ratio adds the present values of the four utilities and then divides total benefits by total costs. It is not an average of the four ratios.

**Table VII-7. Present value of each RIM line (7% nominal, Year 1 dollars)**

| Line | PSE&G | JCP&L | ACE | RECO | New Jersey |
|---|---|---|---|---|---|
| B1 Avoided energy | $228,649 | $140,223 | $60,554 | $9,453 | $438,879 |
| B2 Avoided ancillary services | $7,330 | $4,495 | $1,941 | $303 | $14,070 |
| B3 Avoided capacity | $7,844,952 | $4,625,069 | $1,788,601 | $313,156 | $14,571,777 |
| B4 Avoided transmission | $11,600,775 | $1,603,961 | $1,797,699 | $145,932 | $15,148,366 |
| B5 Avoided distribution | $2,409,059 | $1,420,285 | $549,251 | $96,165 | $4,474,760 |

| Line | PSE&G | JCP&L | ACE | RECO | New Jersey |
|---|---|---|---|---|---|
| B6 Energy DRIPE | $11,432 | $7,011 | $3,028 | $473 | $21,944 |
| B7 Capacity DRIPE | $0 | $0 | $0 | $0 | $0 |
| B13 Participant incentive received | $38,691,589 | $19,345,794 | $17,024,299 | $2,321,495 | $77,383,178 |
| **Total PV of benefits** | **$60,793,787** | **$27,146,838** | **$21,225,373** | **$2,886,976** | **$112,052,974** |
| C1 Participant incentive payments | $38,691,589 | $19,345,794 | $17,024,299 | $2,321,495 | $77,383,178 |
| C2 Program administration | $9,672,897 | $4,836,449 | $4,256,075 | $580,374 | $19,345,794 |
| **Total PV of costs** | **$48,364,486** | **$24,182,243** | **$21,280,374** | **$2,901,869** | **$96,728,972** |
| **RIM ratio = PV benefits ÷ PV costs** | **1.26** | **1.12** | **0.997** | **0.995** | **1.16** |

# Appendix G

In the Matter of Establishing the PowerUp New Jersey Program, Docket No. QO26100658

In the Matter of Advancing Virtual Power Plant (VPP) Program in the State of New Jersey
Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program – Phase 2 Distributed Storage, Docket No. QO26040116

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Overview

- This workbook describes the methodology and assumptions associated with each of the six cost tests laid out in the Order.
- The workbook should be read sequentially. Assumptions already defined in previous test sections will not be repeated, and instead assumption entries in the later test sections will reference the previous section where the assumption was specified.
- The column “EDC-Proposed Assumption Permitted” indicates where EDCs may propose a different assumption (Y/N).
- The BCA analysis shall calculate the net present value of program costs and benefits over the duration of the program using a 7% discount rate.
- Where MW storage capacity allocations (Total, New Storage, or Existing Storage) are referenced in the below assumptions, assume the EDC-specific allocation as outlined in the Board Order.

Ratepayer Impact Measure (RIM) – **GSESP**

Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | **Calculation**<br>**=** (1) Nameplate MW * (2) Performance Factor % * (3) Hours Per Dispatch Event * (4) Arbitrage Price Spread<br>3) Assume 3 hours per dispatch event rule<br>4) 2025 June-Aug Weekday hour 16-18 Average LMP = $98. 2025 June-Aug Weekday hour 0-7 Average LMP = $28. Resulting spread is $70/MWh | **N** |
| B2 | Avoided wholesale electric ancillary | • Zero | **N** |
| B3 | Avoided wholesale electric capacity | **Calculation**<br>= (1) Nameplate MW * (2) Performance Factor % * (3) CP Reduction Effectiveness % * (4) BRA $<br>1) Existing Resource MW + New Resource MW= Total MW nameplate<br>a. "Existing" assumed available immediately, "New" phased in 1/3 each of first 3 program years.<br>2) Assume 58% Performance Factor based on common commercially available BESS configurations and an average 3-hour dispatch<br>3) Assume 95% CP Reduction Effectiveness during 10-year program tenor, 25% during 5 years following program. Note that while EDC dispatch may not be in place following Y10, Staff expects energy storage devices to perform in a relatively similar manner in later years, albeit with much derated effectiveness<br>4) Assume a BRA clearing price of $325/MW-day, with 15% wholesale gross-up to account for costs to serve load, that remains in place for the duration of the program.<br><br>**Methodology Discussion** | **N** |

| | | | |
|---|---|---|---|
| | | • Savings derived from reduced zonal load procurement obligations in BGS. Since BGS Auctions are split into 3 tranches, 33% of savings are felt in year following load recognition, 66% in next year, and 100% in remaining years.<br>In near term, near-term capacity savings would be realized through PJM's accounting of projected behind-the-meter storage deployment in its load forecast, which reduces forecast zonal peak load based on annual state regulatory submissions. Assuming the Order is issued in Q4 2026 and operational in 2027, these forecast reductions should be reflected in time for the 2029/2030 Delivery Year (Program Year 3). | |
| B4 | Avoided electric transmission | **Calculation**<br>= (1) Nameplate MW * (2) Performance Factor (%) * (3) CP Reduction Effectiveness ( * (4) NITS $<br><br>**Methodology Discussion**<br>Methodology largely same as B3 "Avoided wholesale electric capacity" above. The difference is the value is from (4) assumes annual NITS rates from program year 1, escalated by 2.5% annually thereafter.<br><br>Whereas capacity savings arise from reduced forecast BGS procurement obligations, transmission savings come from actual metered reductions during transmission CPs on which Network Service Peak Load (NSPL) obligations are calculated. NSPL obligations are then used to allocate Network Integration Transmission Service (NITS) charges to network customers. The BCA therefore applies the annual NITS rate to the avoided NSPL obligation.<br><br>As a conservative timing assumption, transmission benefits are modeled as accruing on the same phase-in schedule as the BGS procurement cycle, thereby allowing time for program impacts to be demonstrated and incorporated into applicable PJM cost allocation processes | **N** |
| B5 | Avoided electric distribution | **Calculation**<br>= (1) Nameplate MW * (2) Performance Factor % * (3) Avoided Distribution $/kW * (4) Distribution Effective Reduction Rating %<br>3) $1,124 /kW Lifetime Avoided Distribution Cost as derived from EDC's Triennium filings. Over 15 year assumed asset useful lifetime, this amounts to $71.65 per kW-yr (nameplate) | **Y** |

| | | | |
|---|---|---|---|
| | | 4) Assume EDC dispatch are 25% effective in achieving full distribution avoided cost value<br><br>**Methodology Discussion**<br>This benefit category makes up ~10% of total benefits in Staff's preliminary analysis under these assumptions. Staff believes this is the appropriate order of magnitude since the program is focused on capacity/transmission savings. A derating is applied due to imprecision in locational deployment and non-coincident dispatch periods across varying feeder profiles.<br><br>**Source**<br>EDC Triennium filings (JCPL, PSEG, ACE, no RECO) estimated "Lifetime Avoided Distribution Costs" of the entire program based on peak kW reductions. Dividing these two yields an average of $1,124/kW NPV Lifetime Avoided Distribution Costs, which is then converted into an equivalent annual benefit of $71.65 per KW-year before derating to account for device-specific Performance Factors and EDC dispatch effectiveness. | |
| B6 | Electric energy DRIPE | • Zero | **Y** |
| B7 | Electric capacity DRIPE | • Zero | **N** |
| B13 | Participant incentive received | **Calculation**<br>= (1) Nameplate MW * (2) Performance Factor % * (3) Incentive Rate $<br>3) $200/kW for New Resources, $100/kW for Existing Resources<br><br>**Methodology Discussion**<br>Incentive payments for a given performance year are issued after the end of the performance year, even though the cost of making those incentive payments will be recovered during the performance year. | N |
| B15 | Avoided wholesale natural gas and delivered fuel | • Zero | **N** |
| B16 | Avoided RPS REC purchase costs | • Zero | **N** |
| B17 | Avoided wholesale volatility costs | • Zero | **N** |

Cost

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C1 | Participant incentive payments | **Calculation**<br>Amount same as “B13” incentive payments in benefits. Ratepayer recovery of those incentive expenses, by contrast to their payment to beneficiaries, is assumed to occur during the same Performance Year to which they relate. | **N** |
| C2 | Administration costs | **Calculation**<br>= (1) Enrolled Project Count * (2) Annual Program Admin Cost<br>1. Assume an expected project count that accounts for 85% residential projects and 15% small commercial projects.<br>2. Assume $215 per participant per year<br><br>**Methodology Discussion**<br>Program Admin Costs are tied to deployment timelines, phasing in and out. Accounts for ~4% of total project costs.<br><br>**Source**<br>Using each EDC’s Triennium filing, calculated net program cost per enrolled customer (total costs less incentive payments), performed separately for the overall program and Demand Response subset, and developed a blended metric weighted 75% to Demand Response costs and 25% to overall program cost, resulting in the $215 per enrolled customer | **Y** |
| C7 | Lost distribution revenue | **Calculation**<br>= (1) Nameplate MW * (2) Performance Factor % * (3) % Participants on TOU Rates * (4) TOU Arbitrage Value | **Y** |

<table>
<tr>
<td></td>
<td></td>
<td>
1. Assumed 20% will be customers actively pursuing Time of Use (TOU) rate arbitrage<br>
2. See below TOU arbitrage values per EDC<br><br>
<table>
<tr><th></th><th>TOU Arbitrage / Bill Savings Delivery</th><th>TOU Arbitrage / Bill Savings Supply</th></tr>
<tr><td></td><td>($/kW-mo)</i></td><td><i>($/kW-mo)</td></tr>
<tr><td>PSEG</td><td>$ 7.14</td><td>$ 10.88</td></tr>
<tr><td>JCPL</td><td>$ 0.75</td><td>$ 2.69</td></tr>
<tr><td>ACE</td><td>$ -</td><td>$ 4.82</td></tr>
<tr><td>RECO</td><td>$ 2.84</td><td>$ 8.75</td></tr>
</table>
<br>
Methodology Discussion<br>
Assume 20% of enrolled capacity is using battery for TOU arbitrage, the savings from which represent a cost in the form of lost distribution revenues. For Supply portion of bill savings, costs are assumed to impact immediately; for Delivery portion of bill savings assumed to impact after 3 years due to rate case accounting delay.<br><br>
Source<br>
Taking each EDC’s RS TOU rates structures (both Delivery and BGS-RSCP Supply), modeled simple charge/discharge behaviors for a standard residential battery, to derive a EDC-specific $/kW-month TOU arbitrage proxy.
</td>
<td></td>
</tr>
<tr>
<td>C9</td>
<td>Time-value of loan repayments</td>
<td>• Zero</td>
<td>Y</td>
</tr>
</table>

New Jersey Cost Test (NJCT) – **GSESP**

Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | • *Same as RIM B1* | **N** |
| B2 | Avoided wholesale electric ancillary | • *Same as RIM B2* | **N** |
| B3 | Avoided wholesale electric capacity | • *Same as RIM B3* | **N** |
| B4 | Avoided electric transmission | • *Same as RIM B4* | **N** |
| B5 | Avoided electric distribution | • *Same as RIM B5* | **Y** |
| B6 | Electric energy DRIPE | • *Same as RIM B6* | **N** |
| B7 | Electric capacity DRIPE | • *Same as RIM B7* | **N** |
| B8 | Avoided CO2 damages | • Zero<br><br>As stated in the June 18, 2025 Order launching Phase 1 of the GSESP, analysis work previously undertaken by one of the Board's consultants shows that storage deployment will result in significant CO2 emission reductions. However, though the work showed the directional finding of CO2 reductions was robust, specific quantitative estimates of CO2 reductions varied widely based on the choice of input assumptions. Thus, to err on the conservative side, the Board thinks it is reasonable to consider CO2 reductions and other avoided damages from storage deployment as a qualitative benefit rather than as a value that is quantified in a storage BCA.<br>Nonetheless, the Board is also open to EDCs quantifying avoided CO2 and other avoided environmental damages if they propose a reasonable methodology for doing so. | **Y** |

| | | | |
|---|---|---|---|
| B9 | Avoided NOx damages | • Zero | **Y** |
| B10 | Avoided SO2 damages | • Zero | **Y** |
| B12 | Low-income adder | • Zero | **N** |
| B13 | Participant incentive received | • Same as RIM B13 | |
| B15 | Avoided wholesale natural gas and delivered fuel | • Zero | **N** |

Cost

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C1 | Participant incentive payments | • Same as RIM C1 | **N** |
| C2 | Administration costs | • *Same as RIM C2* | **Y** |

Total Resource Test (TRC) – **GSESP**

Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | • *Same as RIM B1* | **N** |
| B2 | Avoided wholesale electric ancillary | • *Same as RIM B2* | **N** |
| B3 | Avoided wholesale electric capacity | • *Same as RIM B3* | **N** |
| B4 | Avoided electric transmission | • *Same as RIM B4* | **N** |
| B5 | Avoided electric distribution | • *Same as RIM B5* | **Y** |
| B6 | Electric energy DRIPE | • *Same as RIM B6* | **N** |
| B7 | Electric capacity DRIPE | • *Same as RIM B7* | **N** |
| B15 | Avoided wholesale natural gas and delivered fuel | • Zero | **N** |
| B16 | Avoided RPS REC purchase costs | • Zero | **N** |
| B17 | Avoided wholesale volatility costs | • Zero | **N** |

Cost

| ID | Category | Methodology | EDC-Proposed |
|---|---|---|---|

| | | | Assumption Permitted? |
|---|---|---|---|
| C1 | Participant incentive payments | • *Same as RIM C1 but only for the 100 MW existing storage at $100/kW* | **N** |
| C2 | Administration costs | • *Same as RIM C2* | **Y** |
| C6 | Participant incremental cost | **Calculation**<br>**=** (1) Nameplate MWh * (2) Total Installed Cost (TIC)<br>1. MWh = New Resource MW * 2.5 hours =<br>2. TIC = $1,250 per kWH<br><br>**Methodology/Assumption**<br>• Standard residential battery duration assumption. TIC derived from Gap Analysis research conducted by staff. | |

Social Cost Test (SCT) – **GSESP**

Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | • *Same as RIM B1* | **N** |
| B2 | Avoided wholesale electric ancillary | • *Same as RIM B2* | **N** |
| B3 | Avoided wholesale electric capacity | • *Same as RIM B3* | **N** |
| B4 | Avoided electric transmission | • *Same as RIM B4* | **N** |
| B5 | Avoided electric distribution | • *Same as RIM B5* | **Y** |
| B6 | Electric energy DRIPE | • *Same as RIM B6* | **N** |

| | | | |
|---|---|---|---|
| B7 | Electric capacity DRIPE | • *Same as RIM B7* | **N** |
| B8 | Avoided CO2 damages | • Zero<br><br>As stated in the June 18, 2025 Order launching Phase 1 of the GSESP, analysis work previously undertaken by one of the Board's consultants shows that storage deployment will result in significant CO2 emission reductions. However, though the work showed the directional finding of CO2 reductions was robust, specific quantitative estimates of CO2 reductions varied widely based on the choice of input assumptions. Thus, to err on the conservative side, the Board thinks it is reasonable to consider CO2 reductions and other avoided environmental damages from storage deployment as a qualitative benefit rather than as a value that is quantified in a storage BCA. Nonetheless, the Board is also open to EDCs quantifying avoided CO2 and other avoided environmental damages if they propose a reasonable methodology for doing so. | **Y** |
| B9 | Avoided NOx damages | • Zero | **Y** |
| B10 | Avoided SO2 damages | • Zero | **Y** |
| B12 | Low-income adder | • Zero | **N** |
| B15 | Avoided wholesale natural gas and delivered fuel | • Zero | **N** |
| B16 | Avoided RPS REC purchase costs | • Zero | **N** |
| B17 | Avoided wholesale volatility costs | • Zero | **N** |
| B18 | Job and savings multiplier benefits | • Zero | **N** |

Cost

| ID | Category | Methodology | EDC-Proposed |
|---|---|---|---|

| | | | Assumption Permitted? |
|---|---|---|---|
| C2 | Administration costs | • *Same as RIM C2* | **Y** |

Program Administrator Cost Test (PACT) – **GSESP**

Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | • *Same as RIM B1* | **N** |
| B2 | Avoided wholesale electric ancillary | • *Same as RIM B2* | **N** |
| B3 | Avoided wholesale electric capacity | • *Same as RIM B3* | **N** |
| B4 | Avoided electric transmission | • *Same as RIM B4* | **N** |
| B5 | Avoided electric distribution | • *Same as RIM B5* | **Y** |
| B6 | Electric energy DRIPE | • *Same as RIM B6* | **N** |
| B7 | Electric capacity DRIPE | • *Same as RIM B7* | **N** |
| B15 | Avoided wholesale natural gas and delivered fuel | • Zero | **N** |
| B16 | Avoided RPS REC purchase costs | • Zero | **N** |
| B17 | Avoided wholesale volatility costs | • Zero | **N** |

Cost

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C2 | Administration costs | • *Same as RIM C2* | **Y** |
| C9 | Time-value of loan repayments | • Zero | **Y** |

Participant Cost Test (PCT) – **GSESP**

Benefits

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| B1 | Avoided wholesale electric energy | **Calculation**<br>1. *Take calculation RIM B1*<br>2. *Then retain only __% of these savings, which are those that accrue to participants*<br><br>**Methodology/Source**<br>Assume only the percentage of savings in this category that accrue to participants over the term. Determine portion of BGS-RSCP that is participants and utilize their portion of the savings for this category | **Y** |
| B3 | Avoided wholesale electric capacity | **Calculation**<br>1. *Take calculation RIM B3*<br>2. *Then retain only __% of these savings, which are those that accrue to participants*<br><br>**Methodology/Source** | **N** |

| | | | |
|---|---|---|---|
| | | Assume only the percentage of savings in this category that accrue to participants over the term. Determine portion of BGS-RSCP that is participants and utilize their portion of the savings for this category | |
| B4 | Avoided electric transmission | **Calculation**<br>1. *Take calculation RIM B4*<br>2. *Then retain only __% of these savings, which are those that accrue to participants.*<br><br>**Methodology/Source**<br>Assume only the percentage of savings in this category that accrue to participants over the term. Determine portion of *all ratepayers* that are participants and utilize their portion of the savings for this category | **N** |
| B5 | Avoided electric distribution | **Calculation**<br>1. *Take calculation RIM B5*<br>2. *Then retain only __% of these savings, which are those that accrue to participants.*<br><br>**Methodology/Source**<br>Assume only the percentage of savings in this category that accrue to participants over the term. Determine portion of *all ratepayers* that are participants and utilize their portion of the savings for this category | **Y** |
| B6 | Electric energy DRIPE | • Zero | **N** |
| B7 | Electric capacity DRIPE | • *Zero* | **N** |
| B13 | Participant incentive received | • *Same as RIM B13* | **N** |
| B14 | Participant bill savings | • *Same as RIM B14* | **N** |
| B19 | Participant avoided retail natural gas | • Zero | **N** |
| B20 | Participant time-value of loan repayments | • Zero | **N** |

Cost

| ID | Category | Methodology | EDC-Proposed Assumption Permitted? |
|---|---|---|---|
| C6 | Participant incremental cost | **Calculation**<br>**=** (1) Nameplate MWh * (2) Total Installed Cost (TIC)<br>1. MWh = New Resource MW * 2.5 hours =<br>2. TIC = $1,250 per kWH<br><br>**Methodology/Assumption**<br>Standard residential battery duration assumption. TIC derived from Gap Analysis research conducted by staff. | **N** |

# Appendix H

In the Matter of Establishing the PowerUp New Jersey Program, Docket No. QO26100658

In the Matter of Advancing a Virtual Power Plant (VPP) Program in the State of New Jersey
Docket No. QO26030099

In the Matter of the Garden State Energy Storage Program – Phase 2 Distributed Storage, Docket No. QO26040116

## Staff's RIM BCA Analysis

| **Scenario 1:**<br><br>**Base Case (No DRIPE)** | **All Ratepayer BCR** |
|---|---|
| **Incentive Levels and Timing of Incentive Costs**<br>• New Resource = $200 / kW Awarded Storage Capacity<br>• Existing Resource = $100 / kW Awarded Storage Capacity<br>• Because incentive payments are made retrospectively based on measured performance, incentive payments are assumed to be received by participants in the year following the applicable Performance Year. By contrast, recovery of those incentive costs is assumed to occur during the same Performance Year to which they relate. Any differences between recovered amounts and paid amounts will be made up in annual true-up.<br><br>**Deployment**<br>• Assumes 100 MW of Existing Resources deployed and participating in PGY1, with 150 MW of New Resources deployed 1/3 annually in PGY1-PGY3.<br><br>**Capacity Savings**<br>• Assumes BRA clears at $325/MW-day cap for duration of program.<br>• 1-year delay before PJM Load Forecast adjustments start flowing through to the BGS auction, with a 3-year phase-in period before the benefits are fully reflected in the BGS auction outcomes. This follows from the BGS structure in which | 1.98 |

only 1/3 of the energy supply for a given energy year is procured in each annual BGS auction.

- The analysis conservatively assumes that PJM does not account for the load reductions resulting from Block 1 until the 2028, such that the first delivery year in which the program starts to produce capacity savings is the 2029/2030 delivery year that will run from June 1, 2029 to May 31, 2030.
- The analysis further conservatively assumes that the resulting load forecast reductions from Block 1 match the load reductions achieved by program in practice. This is conservative because PJM has informed Staff that its current practice is to simply decrease the load forecast by the projected nameplate capacity of distributed storage deployment. Staff makes this assumption because PJM has also indicated that it will change that practice to use more realistic assumptions once distributed storage starts having a material impact on the load forecast.

**Transmission Savings**

- Whereas capacity savings arise from reduced forecast BGS procurement obligations, transmission savings come from actual metered reductions during transmission CPs on which Network Service Peak Load (NSPL) obligations are calculated. NSPL obligations are then used to allocate Network Integration Transmission Service (NITS) charges to network customers. The BCA therefore applies the annual NITS rate to the avoided NSPL obligation.

- As a conservative timing assumption, transmission benefits are modeled as accruing on the same phase-in schedule as the BGS procurement cycle, thereby allowing time for program impacts to be demonstrated and incorporated into applicable PJM forecasting and allocation processes.

**Distribution Savings**

- Based on EDC Triennium values, this assumption quantifies the value of lifetime avoided distribution costs, levelized annually over the duration of the program. As a conservative assumption, these benefits are heavily discounted to account for the fact there is currently no locationally-targeted deployment. in Block 1.

**Program**

- 58% Performance Factor, 3-hour dispatch event duration

**Annual BCR Detail**

| EDC | EDC-BCR | Weighted | 2027/2028 | 2028/2029 | 2029/2030 | 2030/2031 | 2031/2032 | 2032/2033 | 2033/2034 | 2034/2035 | 2035/2036 | 2036/2037 | 2037/2038 | 2038/2039 | 2039/2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PSEG | 2.00 | 1.98 | 0.28 | 0.73 | 1.32 | 1.90 | 2.41 | 2.42 | 2.43 | 2.44 | 2.45 | 2.46 | 2.49 | 2.57 | 2.71 |
| JCPL | 1.97 | | 0.34 | 0.84 | 1.26 | 1.86 | 2.25 | 2.25 | 2.26 | 2.27 | 2.27 | 2.28 | 2.56 | 2.95 | 3.93 |
| ACE | 2.00 | | 0.32 | 0.81 | 1.26 | 1.90 | 2.33 | 2.33 | 2.34 | 2.35 | 2.36 | 2.37 | 2.61 | 2.96 | 3.81 |
| RECO | 1.64 | | 0.29 | 0.76 | 1.13 | 1.61 | 1.92 | 1.92 | 1.92 | 1.92 | 1.92 | 1.92 | 2.08 | 2.23 | 2.52 |

| Scenario 2:<br><br>Low Long-Term Capacity Price Case | All Ratepayer BCR |
|---|---|
| Unlike the above, this case assumes elevated PJM BRA clearing prices do not persist indefinitely and that a temporary price cap is ultimately removed. Once the cap is removed, the peak reduction characteristics of the program influence the formation of the demand curve and have suppressive effects on the BRA clearing prices, lowering capacity costs. This savings model is represented here:<br><br>Same assumptions as above, except:<br>**Capacity Savings & Demand Reduction Induced Price Effects (DRIPE)**<br>• BRA clearing price remains at $325/MW-day through Delivery Year 2031/2032.<br>• Beginning in Delivery Year 2032/2033, BRA clearing prices are assumed to decline to $100/MW-day and remain at that level for the balance of the study period. For context, prior to the capacity price spike in the 2025/2026 BRA, the average capacity price in the EMAAC Locational Deliverability Area (the PJM capacity market zone that encompasses New Jersey) averaged about $147/MW-day. This sensitivity case is therefore a highly conservative BCA that assumes future long-term capacity prices will be well below historical averages.<br>o Procurement obligations are still reduced, but lower capacity prices means the resulting cost savings from avoided capacity purchases are lower<br>• Beginning in Delivery Year 2032/2033, capacity market prices are assumed to reflect the long-term price suppressive effects of DRIPE resulting from increased demand-side resource penetration. Consistent with the assumption of a relatively low capacity clearing price, this sensitivity case also assumes BRAs for Delivery Year 2032/2033 and onwards are clearing between points B and C on the Variable Resource Requirement (VRR) Curve, where the VRR Curve's slope is lower and thus DRIPE impacts are muted. If BRAs instead cleared between points A and B on the VRR curve, DRIPE impacts would be significantly greater and the resulting capacity savings much higher than what is assumed here.<br>o Reduced market clearing prices retained as savings | 1.96 |

**Annual BCR Detail**

| EDC | EDC-BCR | Weighted | 2027/2028 | 2028/2029 | 2029/2030 | 2030/2031 | 2031/2032 | 2032/2033 | 2033/2034 | 2034/2035 | 2035/2036 | 2036/2037 | 2037/2038 | 2038/2039 | 2039/2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PSEG | 1.99 | 1.96 | 0.28 | 0.73 | 1.32 | 1.90 | 2.41 | 2.40 | 2.40 | 2.41 | 2.41 | 2.42 | 2.59 | 2.56 | 2.66 |
| JCPL | 1.95 | | 0.34 | 0.84 | 1.26 | 1.86 | 2.25 | 2.22 | 2.23 | 2.23 | 2.23 | 2.24 | 2.70 | 2.94 | 3.85 |
| ACE | 1.99 | | 0.32 | 0.81 | 1.26 | 1.90 | 2.33 | 2.30 | 2.31 | 2.31 | 2.32 | 2.33 | 2.75 | 2.95 | 3.73 |
| RECO | 1.62 | | 0.29 | 0.76 | 1.13 | 1.61 | 1.92 | 1.89 | 1.89 | 1.89 | 1.88 | 1.88 | 2.20 | 2.22 | 2.47 |

| Scenario 3:<br><br>No Distribution Benefits | All Ratepayer BCR |
|---|---|
| Scenario 3 retains all assumptions from Scenario 2 except for the treatment of distribution benefits, which are excluded entirely. Given that distribution benefits were previously discounted and accounted for only about 10% of total benefits, their removal has limited effect on the BCR, which remains positive. | 1.76 |

**Annual BCR Detail**

| EDC | EDC-BCR | Weighted | 2027/2028 | 2028/2029 | 2029/2030 | 2030/2031 | 2031/2032 | 2032/2033 | 2033/2034 | 2034/2035 | 2035/2036 | 2036/2037 | 2037/2038 | 2038/2039 | 2039/2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PSEG | 1.81 | 1.76 | 0.00 | 0.53 | 1.16 | 1.76 | 2.27 | 2.25 | 2.26 | 2.27 | 2.27 | 2.28 | 2.42 | 2.34 | 2.35 |
| JCPL | 1.72 | | 0.00 | 0.61 | 1.08 | 1.68 | 2.07 | 2.05 | 2.05 | 2.05 | 2.06 | 2.06 | 2.47 | 2.61 | 3.26 |
| ACE | 1.77 | | 0.00 | 0.58 | 1.09 | 1.73 | 2.15 | 2.13 | 2.14 | 2.14 | 2.15 | 2.16 | 2.53 | 2.64 | 3.19 |
| RECO | 1.43 | | 0.00 | 0.55 | 0.96 | 1.45 | 1.77 | 1.74 | 1.73 | 1.73 | 1.73 | 1.73 | 2.01 | 1.96 | 2.07 |