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May 15, 2026

Via Electronic Mail
Sherri L. Lewis Secretary of the Board
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Re : In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid
BPU Docket No.: QO24030199

Dear Secretary Lewis:

The Division of Rate Counsel ("Rate Counsel"), pursuant to its statutory mandate to represent and protect the interests of New Jersey ratepayers, under N.J.S.A. 52:27EE-48, respectfully submits these comments in response to the Board of Public Utilities (the "Board" or "BPU") Request for Information ("RFI"), dated February 3, 2026, BPU Docket No. QO24300199. In its April 20, 2026 Notice, Board Staff states that the RFI was "published in order to comply with the Executive Order No. 2"[1] However, Executive Order 2 instructed the Board to direct the electric distribution utilities to submit memoranda or filings that address a number of topics related to the speed and success of DER interconnections.[2] Further, the Executive Order instructed the Board to "exercise its discretion to determine necessary and appropriate steps to effectuate" the Executive Order's directives. [3]

[1] I/M/O Developing Integrated Distributed Energy Resource Plans To Modernize New Jersey's Electric Grid, BPU Docket No. QO24030199, Revised Notice (Apr. 20, 2026).
[2] Executive Order 2 at Paragraph 7.
[3] Id. At Para 11 (emphasis added).

Rate Counsel is generally supportive the Board's efforts to advance distributed energy resources ("DERs") interconnected to New Jersey's electric distribution grid, as long as, doing so has its intended consequence of reducing overall costs for New Jersey's electric ratepayers. Rate Counsel believes increasing DERs can help lower overall energy prices if interconnection of DERs is achieved economically. Rate Counsel is also generally supportive of grid modernization, and storage deployment consistent with the State's clean energy goals under the Electric Discount and Energy Competition Act ("EDECA"), N.J.S.A. 48:3-49 et seq., and subsequent legislation including N.J.S.A. 48:3-87 et seq.

As Board Staff is aware, "[e]xecutive orders, when issued within their appropriate constitutional scope, are an accepted tool of gubernatorial action," but may not conflict with the terms of existing legislation.[4] The Board is therefore bounded by its existing statutory authority. The Governor's Executive Order 2 does not purport to confer new powers on the Board, and it expressly disclaims creating legal obligations enforceable by third parties.[5] It follows that any Board action taken in response to, or in "compliance with," EO 2 must be independently grounded in the Board's enabling statute and must comply with the Administrative Procedure Act's ("APA's") applicable procedural requirements – including its applicable rulemaking requirements.

Notwithstanding the Board's recent adoption of substantially revised interconnection rules on January 6, 2026.[6] This April 20 Notice is one of a few other stakeholder proceedings (collectively, the "Notices") that have been issued over the last three weeks to examine the acceleration of DER interconnections, among other things.[7] As explained more fully below, the

[4] Communications Workers of America, AFL-CIO v. Christie, 413 N.J. Super. 229, 254 (App. Div. 2010).
[5] See EO 2 at Para. 12.
[6] 58 N.J.R. 72
[7] Modernization of the Traditional Electric Distribution Utility Business Model (Apr. 16, 2026); Request for Information ("RFI") on the evaluation and development of distributed energy resource ("DER") programs (May 6,

Board should be mindful not to blur the lines between distinct proceedings and thereby bypass the APA's notice and comment requirements.[8] The agglomeration of concurrent, rushed stakeholder proceedings will not give the public adequate time to respond, nor allow newly adopted interconnection rules a practical opportunity to be tested. Rather the Governor's energy policy objectives may be undermined by a disorderly process that fails to develop a record of substantial, credible evidence on which the Board may rely to make its own analysis and reasoned decision, not just mere compliance with an express or implied mandate.

Indeed, Rate Counsel has concerns that the initiatives outlined in the Notices by BPU Staff for grid modernization and storage deployment are inconsistent with foundational ratemaking principles requiring that rates remain just and reasonable, N.J.S.A. 48:2-21(b), and that costs are allocated in a manner that is non-discriminatory, transparent, and supported by demonstrable benefits. Programs that continue to socialize costs, without commensurate and measurable net benefits, risk imposing unjustified financial burdens on ratepayers who do not receive the value promised.

Accordingly, Rate Counsel's comments emphasize:

- Rigorous cost-benefit analysis prior to program approval;
- Ratepayer protections against cross-subsidization;
- Clear delineation between utility and competitive market functions;
- Transparency in program funding, revenues, and performance.

2026); In The Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid (may 8, 2026).

[8] See ***In re Provision of Basic Generation Service***205 N.J. 339, 356 (2011)(finding that the Board's regulatory expertise does not confer discretion to bypass APA procedures when those procedures apply)

Rate Counsel's recommendations are guided by the following core legal requirements:

- Full transparency and accountability in program design, funding, and implementation with no recovery of costs absent demonstrable, quantifiable ratepayer benefit; [9]
- No cross-subsidization between customer classes or program participants and non-participants; [10]
- Ratepayer-funded incentives must be tied to verified performance outcomes and not merely installed or increased capacity. [11]

In the following response we I) discuss some of the background on DER and energy storage systems ("ESS") initiatives in the State, II) Identify Procedural Deficiencies in the current Process; III) Recommend a structured process that should be used for managing these initiatives to achieve their objectives, IV) present technical considerations or "tools" which can help increase DER development, and V) provide responses to electric distribution companies ("EDC") and stakeholder comments filed in response to this RFI.

I. Background on DER and ESS Initiatives in New Jersey

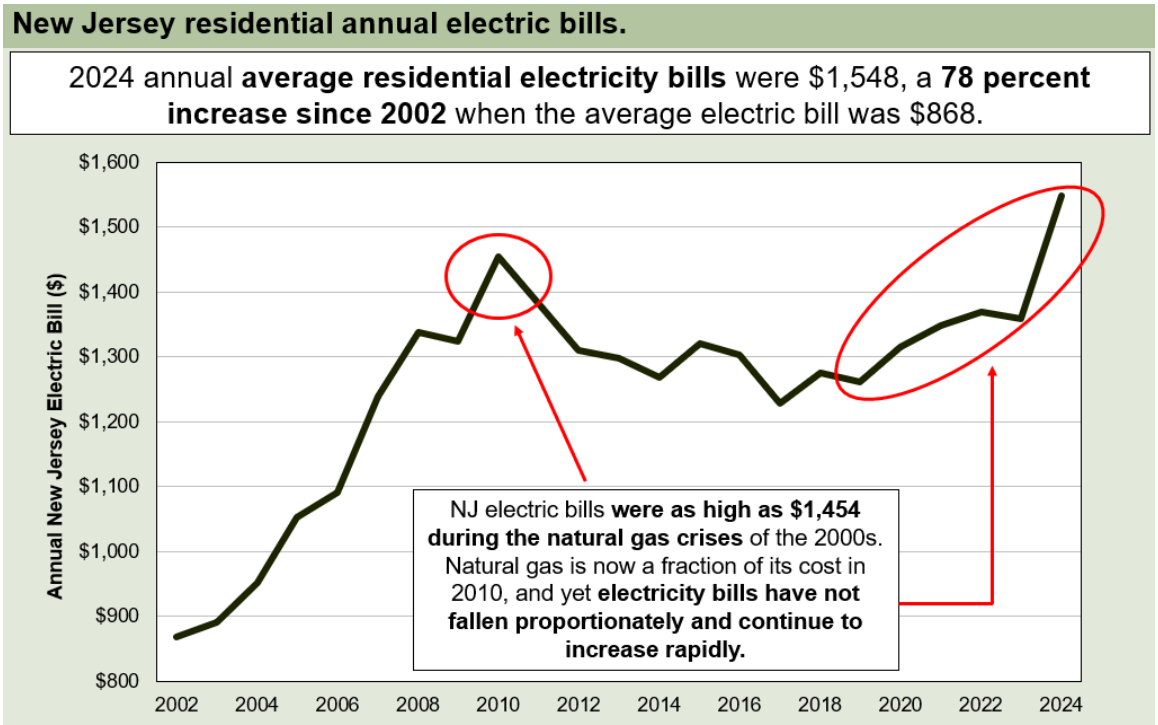
Board Staff has initiated a sweeping and expansive set of proceedings associated with the development of Virtual Power Plants ("VPPs"), distributed energy resource ("DER") aggregation, grid flexibility services, integrated distributed energy resource planning, and Phase 2 of the Garden State Energy Storage Program ("GSESP"). The scope of these proceedings is extraordinary in breadth and potential financial significance, yet appear to be proceeding at a breakneck speed with little to limited stakeholder participation. The initiatives collectively contemplate substantial new

[9] See In re Electric Distribution Utility Grid Modernization, BPU Docket No. QO18101111, Order dated May 23, 2019 ("Grid Modernization Order") at 15–18 (requiring demonstration of net benefits and stakeholder transparency).
[10] See In re Successor Solar Incentive Program, BPU Docket No. QO20020184, Order dated July 28, 2021 ("SuSI Order") at 28–32.
[11] See https://www.nj.gov/bpu/newsroom/2025/approved/20250618solar.html [11]

utility capital investment, expanded utility operational responsibilities, new subsidy and incentive structures, advanced metering and telemetry systems, new DER management systems ("DERMS"), customer-facing technology deployment, enhanced data infrastructure, and potentially extensive social-program overlays directed at low- and moderate-income ("LMI") participation.

Despite the extraordinary breadth and cost implications of these proposals, the notices fail to establish a coherent, transparent, or methodical regulatory framework for evaluating the necessity, cost-effectiveness, sequencing, governance, and affordability impacts of the contemplated programs. The proceedings also fail to identify the core policy problem New Jersey is attempting to solve; specifically, the measurable objectives associated with the proposed initiatives and the standards by which success or failure will ultimately be judged. The lack of procedural structure is particularly troubling because the initiatives under consideration have the potential to materially affect electric rates for all New Jersey consumers, particularly residential and lower-income households already facing escalating energy affordability challenges. Figure 1 below shows that electric bills for residential customers in New Jersey have increased by 78 percent over the last two decades.

Figure 1: Historical Residential Electric Bills



Source: EIA Form 861

The Notices appear to presume that expanded DER aggregation, VPPs, storage deployment, and advanced grid modernization activities are inherently beneficial to ratepayers without first establishing a factual record demonstrating that these programs are necessary, cost-effective, superior to alternatives, or appropriately scaled to the actual reliability and affordability problems facing the State.

II. Board Staff's Notices Include Procedural Deficiencies

a. The Proceedings Lack a Clearly Defined Problem Statement

One of the most significant shortcomings of the BPU's notices is the absence of a clearly articulated problem statement. While the Notices repeatedly reference "reliability," "affordability," "grid modernization," "resiliency," and "peak demand reduction," they do not

meaningfully quantify the underlying problems the New Jersey seeks to solve, nor do the notices distinguish between short-term reliability concerns, long-term planning considerations, PJM market design issues, distribution-level operational constraints, or broader decarbonization policy objectives. The Notices broadly cite concerns associated with rising demand growth (without acknowledging that much of this growth is due to data center load demand), PJM reserve margins, and the need to accelerate distributed energy resource participation. However, there is no analytical framework explaining:

- The magnitude of the actual reliability deficiency in New Jersey;
- The portion of that deficiency that can realistically be addressed through DER aggregation or VPP deployment;
- The comparative cost of VPP-oriented solutions relative to traditional supply-side or transmission solutions;
- The expected magnitude of ratepayer savings, if any;
- The expected timing of such savings;
- The distributional impacts of these programs across customer classes;
- Why ratepayers, not data centers responsible for much of the load demand, should fund these projects; or
- Whether these programs primarily serve climate-policy objectives rather than affordability objectives.

The Notices effectively assume that more DER participation, more aggregation, more telemetry, more storage, and more utility infrastructure investment are not only inherently desirable but will resolve these issues without clear quantifiable performance metrics. These assumptions are unsupported by a credibly, developed factual record.

b. <u>The RFI Structure Reflects a Predetermined Policy Outcome</u>

The structure of the Notices strongly suggests that the BPU Staff has already reached significant policy conclusions before developing an evidentiary record. Nearly all 75 of the questions asked in the Board's April 20, 2026 Notice (under Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, and QO24030199) assume that VPPs, distributed

storage expansion, DER aggregation, advanced telemetry systems, and utility-operated DERMS frameworks should proceed. The questions largely focus on implementation mechanics, cost recovery, interoperability, dispatch structures, and aggregation protocols; rather than whether these programs are necessary, economically justified, or in the public interest. Indeed, ratepayer impacts and affordability concerns receive minimal attention relative to the significant number of technical, operational, and implementation questions. Only one section explicitly references "Cost Effectiveness and Ratepayer Impacts," even though the initiatives contemplated in the notices will likely result in billions of dollars in future utility capital expenditures and programmatic costs over time. If more substantive cost controls and performance metrics are not placed on these initiatives at inception the impact on utility bills is likely to be significant.

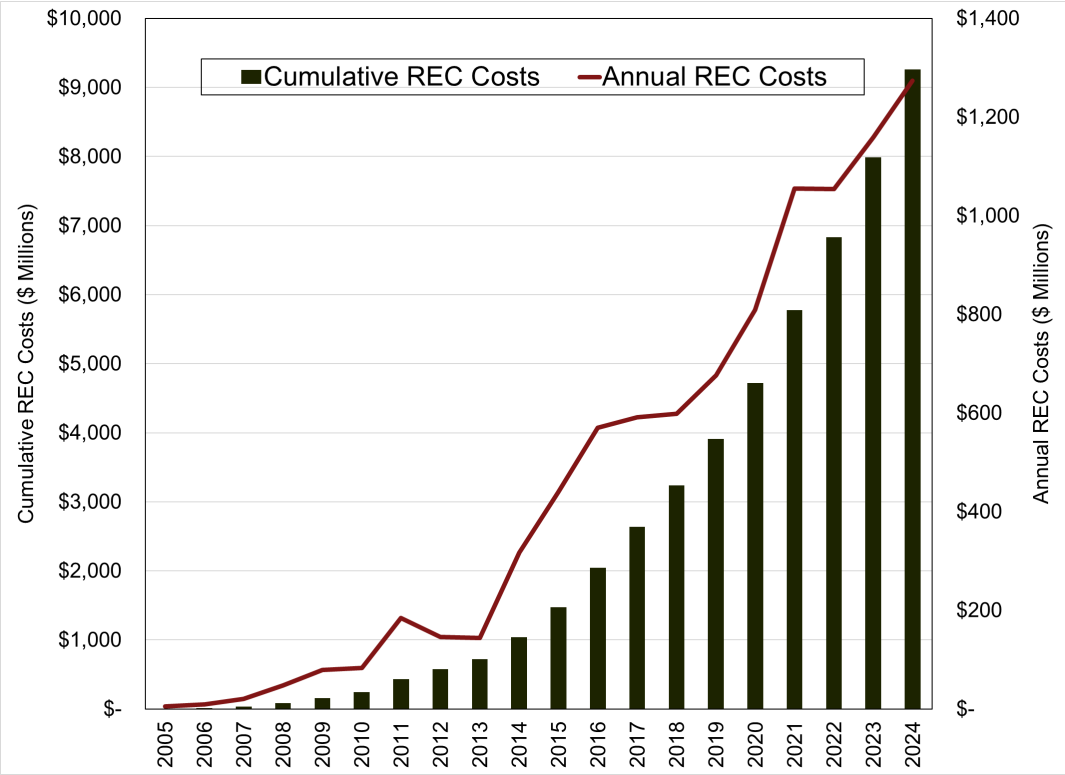
The imbalance is particularly concerning because New Jersey consumers are already experiencing significant upward pressure on electric bills from multiple overlapping policy initiatives, including:

- Energy efficiency program expenditures;
- Electrification initiatives;
- Transmission expansion;
- AMI deployment;
- Solar and storage incentive programs;
- PJM capacity market pressures; and
- Broader utility infrastructure modernization initiatives.

The energy efficiency program alone resulted in budget expenditures and estimated shareholder returns costing ratepayers $2.4 billion in Triennium 1, $5.2 billion in Triennium 2, and a proposed $3 billion for the upcoming set of energy efficiency programs. In total, by the end of third iteration of energy efficiency programs, ratepayers will have paid an estimated $10.7 billion for energy efficiency programs in New Jersey.

As New Jersey's Renewable Energy Credit ("REC") retirements continue to grow, RECs reached record-high volumes in 2024, resulting in an annual cost of $1.27 billion in 2024. The cumulative cost of the REC programs through 2024 was $9.26 billion, as shown in Figure 2 below.

Figure 2: Annual and Cumulative REC Expenditures



Source: 2024 RPS Compliance Report

The Notices do not attempt to quantify how the proposed DER and VPP initiatives will interact with these ongoing substantial cost drivers. Instead, the immediate stakeholder proceedings appear designed to facilitate the rapid expansion of utility and third-party DER-related investment without first establishing guardrails regarding affordability, prudency, sequencing, or cost containment.

c. The Notices Fail to Establish a Clear Procedural Framework

Another fundamental problem with the current approach is the absence of a clearly defined procedural structure. The notices seek input on an extraordinarily broad range of subjects, including:

- VPP market design;
- DER aggregation structures;
- DERMS platforms;
- Telemetry and AMI requirements;
- Storage incentives;
- Locational value methodologies;
- Grid flexibility tariffs;
- Performance incentives;
- Wholesale market participation;
- EDC ownership structures;
- Data governance;
- Cybersecurity frameworks;
- Customer privacy protections;
- Low-income participation mechanisms; and
- Cost recovery structures.

Yet the Notices provide almost no information regarding how these issues will ultimately be resolved procedurally. There is no defined schedule for technical conferences, evidentiary hearings, stakeholder workshops, rulemakings, contested case procedures, pilot evaluations, or cost-effectiveness review frameworks. The absence of procedural clarity is inconsistent with sound utility regulatory practice. Programs of this magnitude should not proceed through loosely defined RFIs without a clear roadmap regarding:

- How costs will be evaluated;
- What standards will govern approval;
- How ratepayer protections will be implemented;
- Whether pilot programs will precede full-scale deployment;
- What evidentiary burdens utilities and third parties must satisfy;
- How prudency will be reviewed; and
- How affordability impacts will be measured and mitigated.

d. The Current Approach Is Inconsistent with Prior New Jersey Regulatory Precedent

The procedural shortcomings of the notices are particularly striking when compared to how New Jersey has historically approached other major energy policy transformations. For example, New Jersey's solar market redesign efforts, including the transition from the Solar Renewable Energy Certificate ("SREC") framework to the Successor Solar Incentive ("SuSI") program and the broader Generic Market Design Initiative, were undertaken through extensive stakeholder proceedings, technical conferences, formal Board orders, and iterative comment opportunities. Those proceedings involved years of stakeholder engagement and detailed analytical development regarding incentive structures, cost impacts, market stability, and ratepayer consequences.

Similarly, the development of the Garden State Energy Storage Program ("GSESP") involved approximately two years of stakeholder engagement prior to implementation. The BPU's notices acknowledge that Phase 1 of the GSESP followed an extended period of structured stakeholder activity. In contrast, the current VPP and DER aggregation initiatives appear to contemplate extraordinarily broad policy development on compressed timelines rather than by a carefully developed evidentiary record.

The same pattern is evident in New Jersey's AMI proceedings. Following a pilot program in Rockland Electric Company's service territory and reports filed with the Board, AMI deployment proposals involved detailed utility filings, minimum filing requirements, cost-benefit analyses, technical evaluations, implementation plans, cybersecurity considerations, and extensive review of customer impacts. Utilities were generally required to demonstrate:

- Operational benefits;
- Customer savings opportunities;
- Reliability improvements;

- Metering accuracy enhancements;
- Demand response capabilities;
- Implementation risks; and
- Net economic benefits.

The Notices, by contrast, appear to seek simultaneous development of multiple interdependent regulatory frameworks without first establishing the analytical foundation necessary to support those investments.

e. The Proceedings Risk Encouraging Expansive Utility Capital Spending Without Adequate Oversight

A central concern associated with the Notices is the extent to which they may create a pathway for substantial utility capital expenditures without sufficient oversight or cost discipline. The questions contained in the notices repeatedly contemplate:

- Advanced DERMS deployment;
- AMI upgrades;
- Grid modernization investments;
- Bidirectional power flow upgrades;
- Telemetry systems;
- Distribution automation investments;
- Data infrastructure expansion;
- Communications systems; and
- Customer-side integration technologies.

Many of these investments would likely become utility rate base assets and recovered from ratepayers over long periods of time. Yet, the Notices provide virtually no discussion regarding prudency standards, analysis of alternative solutions, competitive procurement safeguards, or mechanisms to prevent overbuilding.

The proceedings also raise concerns regarding the potential expansion of utility operational authority into competitive DER markets. Several questions contemplate significant utility

involvement in aggregation, dispatch, DER management, and potentially even ownership of distributed storage resources. Such approaches raise longstanding concerns regarding competitive neutrality, market distortion, and utility encroachment into markets historically served by competitive providers.

Absent strong procedural safeguards, the proceedings risk evolving into broad utility infrastructure expansion initiatives with limited accountability regarding whether the resulting expenditures produce measurable net benefits for ratepayers.

f. Affordability and Distributional Impacts Require Far Greater Attention

The Notices repeatedly invoke "energy affordability" as a policy justification. However, they contain almost no meaningful framework for evaluating whether the contemplated programs will actually reduce costs for customers on a net basis. Generalized claims of system benefit are insufficient. The Board must require quantifiable, demonstrated benefits, not speculative or aspirational ones. Absent such evidence, the cost socialization the Notices' proposed initiatives will generate could create a future violation of N.J.S.A. 48:2-21 which requires public utility rates to be just and reasonable.

This omission is particularly troubling given the significant affordability pressures already facing New Jersey households. Lower-income customers are especially vulnerable to cumulative bill impacts associated with overlapping policy initiatives and infrastructure programs. The proceedings fail to meaningfully address:

- Bill impacts on residential customers;
- Distributional impacts across income groups;
- The regressive nature of non-bypassable surcharges;
- The interaction between DER incentives and non-participating customers;
- Potential cross-subsidization concerns;
- Whether projected benefits are speculative or guaranteed; and

- The extent to which benefits accrue disproportionately to higher-income participants capable of adopting DER technologies.

The Notices also fail to establish any meaningful cost-effectiveness framework. While one question asks generally how cost-effectiveness should be evaluated, there is no indication regarding:

- Which cost-effectiveness test will be used;
- Whether societal benefits will be included;
- How avoided costs will be quantified;
- How reliability benefits will be monetized;
- How speculative future benefits will be discounted; or
- What threshold programs must satisfy before costs can be imposed on ratepayers.

The specific assumptions used to test cost-effectiveness are particularly important given the Board's recent proposal in its Energy Efficiency Triennium 3 straw proposal to dramatically increase the social cost of carbon values utilized in the New Jersey Cost Test ("NJCT") framework. By simply transitioning from using a three percent to two percent discount rate scenario, the Board's estimated social cost of carbon increased from $80 to $233 per ton, or by nearly threefold. To put that into perspective, the Board's most recent Triennium 2 extension proposal estimated that avoided emissions, under the old cost-effectiveness methodology, made up nearly half of the estimated annual benefits for its energy efficiency programs ($916 out of $2,089). If the new, significantly higher emissions estimates were used, those same avoided emissions would be valued at $2.748 billion, creating an additional $1.832 billion in headroom for energy efficiency spending which will ultimately be paid by ratepayers.

g. The Proceedings Improperly Conflate Multiple Distinct Policy Objectives

The Notices also suffer from a lack of conceptual clarity because they appear to merge multiple distinct policy objectives into a single omnibus initiative. Among the objectives referenced are:

- Reliability enhancement;
- Peak demand reduction;
- Grid modernization;
- Decarbonization;
- Wholesale market participation;
- Customer empowerment;
- Electrification support;
- Equity initiatives;
- Resiliency enhancement; and
- Economic development.

These objectives may not always align and, in some cases, may directly conflict. For example, programs designed to maximize DER participation or accelerate electrification may increase overall system costs or peak demand under certain conditions. Similarly, maximizing customer participation may conflict with efforts to ensure operational reliability or cost containment. A disciplined regulatory process should separately define each objective, quantify its importance, establish measurable metrics, and evaluate tradeoffs transparently. The current Notices – and extremely limited time allotted to comment – do not do so.

The proceedings contemplate potentially transformative changes to the electric system involving DER aggregation, VPPs, distributed storage, advanced telemetry, DERMS deployment, grid modernization, and expanded utility operational responsibilities. Yet the notices lack the foundational analytical and procedural safeguards necessary for initiatives of this magnitude. They do not clearly identify the problem being solved, establish measurable objectives, define

affordability protections, or articulate a coherent regulatory roadmap. Instead, they appear to assume that expansive DER deployment and aggregation initiatives at any level are inherently beneficial while deferring critical questions regarding cost-effectiveness, ratepayer impacts, competitive neutrality, and implementation governance.

The Board's current approach is inconsistent with the careful, methodical, and stakeholder-driven processes New Jersey has historically employed for major initiatives such as solar market redesign, AMI deployment, and energy storage program development. Those prior efforts recognized that major utility-sector transformations require extensive evidentiary development, transparent cost-benefit evaluation, iterative stakeholder engagement, and clearly defined procedural safeguards. Before moving forward with expansive new DER and VPP frameworks, the Board should establish a disciplined regulatory structure that places affordability, prudency, transparency, and measurable ratepayer benefits at the center of the process.

III. RECOMMENDATIONS FOR A STRUCTURED PROCESS THE BOARD SHOULD USE TO ACHIEVE ITS OBJECTIVES

The Board's April 16, 21, May 6, and 8, 2026 Notices imply significant and transformative changes to the electric utility system without first establishing a disciplined procedural schedule/process that first and foremost identifies the specific problem(s) to be solved by an expansive set of new regulatory changes. More importantly, the RFIs are entirely deficient in examining the cost and benefits (in any formalized, empirical manner) nor examining the rate impacts and affordability implications of its proposed changes. In fact, across over 75 questions posed in the May 6, 2026 RFI, only one appears to be directly related to ratepayer impacts. Further, the RFIs fail to address how the changes impact existing New Jersey regulatory processes and market structures for electricity services and how those may impact broader regional markets.

Such an approach fails to follow past Board practices based on more detailed analysis, defined stakeholder processes, and clearly articulated regulatory changes, guidelines/rules, and actions.

The Board should ground the process in several overarching principles: affordability first; problem definition before solution design; pilot testing before full deployment; technology neutrality; competitive neutrality; incremental and sequential development; and transparency supported by evidentiary records.

a. Proposed Process

The Board should establish a process that will move in an expedited, yet thorough manner, that: (1) defines problems, challenges, and goals; (2) identifies a range of potential solutions and mechanisms to execute those solutions; (3) seeks a wide range of initial stakeholder input into those solutions, new regulations, or investments through a comment and workshop process; (4) offers a "straw man" set of proposed regulation and guidelines and offers stakeholders an opportunity to comment on this straw proposal; (5) develop a final proposal that addresses and reconciles stakeholder input and concerns into a final set of proposals upon which the Board can directly vote that has clear implementation schedule, and where needed, identifies processes where further market design rules, implementation goals, and other matters can be addressed.

i. Phase 1 Problem Definition and Analysis

The April 21, 2026 RFI envisions an expansive and aggressive change of the current New Jersey electric distribution grid. The Board should not embark on such actions until it clearly examines and identifies a range of recourse, incentives and market designs that justify such actions, using extensive cost-benefit analysis ("CBA") and rate impact analyses.

Before designing programs or authorizing expenditures, the Board should first conduct an appropriate DER/VPP needs and reliability assessment that identifies and examines all potential

options, collects data and comment on such an assessment, and clearly articulates the rate impacts of various scenarios. This analysis must be focused exclusively on identifying actual reliability deficiencies, capacity constraints, localized distribution constraints, load growth forecasts, peak demand drivers, resiliency concerns, hosting capacity limitations, and affordability pressures.

Utilities and PJM should be required to submit standardized analyses, including localized feeder congestion studies, hosting capacity analyses, electrification forecasts, outage statistics, avoided-cost studies, and historical demand response performance data. Independent consultants retained by the Board should review utility assumptions and methodologies to ensure objectivity.

The conclusion of this phase should include a clearly articulate set of DER/VPP options and timelines in which these options could be executed with goals/anticipated outcomes for all identified resource/incentive/market design options.

ii. Phase 2 Solutions Identification, CBA, and Rate Impacts

The next step in the process should take the technical potentials for new DER/VPP proposals and apply these to a set of standardized cost-effectiveness tests, including ratepayer cost tests, participant tests, utility system cost tests, and societal tests if applicable. The Board should clearly specify discount rates, avoided-cost methodologies, treatment of speculative benefits, treatment of emissions reductions, and risk adjustments and utilize models comparable to those in the NJCT used for energy efficiency evaluation purposes.

The Board should also establish explicit affordability metrics, including bill impact thresholds, cumulative surcharge tracking, residential energy burden metrics, and low-income customer affordability standards.

Future, DER/VPP proposals should be required to evaluate participant versus non-participant impacts, customer class impacts, and distributional impacts across income groups. Benefits should be measurable, auditable, and verifiable rather than speculative.

Part of this cost effectiveness analysis should include an investigation into the way in which market roles are defined and markets for electricity services are structured in New Jersey. The Board should examine the competitive and cost-effectiveness of whether utilities may own DER assets, whether utilities may operate aggregation platforms, and what competitive safeguards are necessary to preserve neutrality between utilities and third-party market participants. The Board should also coordinate with PJM and FERC frameworks to clarify retail versus wholesale jurisdictional boundaries and avoid conflicts between retail incentives and wholesale market participation rules.

DERs participating in PJM wholesale markets must not simultaneously receive retail compensation for identical services. Such duplication would constitute unjust and unreasonable ratemaking under N.J.S.A. 48:2-21. Where DERs receive ratepayer-funded incentives, any wholesale revenues should be fully disclosed and credited to ratepayers where appropriate. Implementation should align with federal wholesale market rules (including FERC Order 2222) without imposing duplicative or conflicting state requirements that increase costs to ratepayers.

At the conclusion of this phase, the Board should issue a formal report with findings identifying which problems are substantiated, their magnitude and geographic scope, and whether DER or VPP solutions appear potentially appropriate and cost-effectiveness with a preference to adopting processes that create greater empirical benefits relative to their costs. No major implementation decisions should occur before this foundational record, including clear rate impacts, is established.

Given the state of emergency declared by the Governor on the affordability of electric rates, prior to authorizing any VPP or DER programs, the Board must conduct a robust, forward-looking cost-benefit analysis consistent with its prior directives in grid modernization proceedings. See In re Electric Distribution Utility Grid Modernization, BPU Docket No. QO18101111, Order dated May 23, 2019 ("Grid Modernization Order") at 15–18 (requiring demonstration of net benefits and stakeholder transparency). The analysis should:

- Quantify avoided capacity, transmission, and distribution costs;
- Include sensitivity scenarios reflecting performance variability;
- Distinguish between participant and non-participant impacts.

Absent such analysis, program approval would risk violating the Board's obligation under N.J.S.A. 48:2-21(b).

Further, any ratepayer-funded incentives must be tied to verified performance outcomes, not installed capacity.[12] Rate Counsel opposes the imposition of non-bypassable charges absent a clear showing that VPP and DER programs deliver system-wide benefits.[13]

iii. Coordination with the Board's existing Programs is Essential

The Board must ensure that distributed storage resources do not receive duplicative compensation streams (e.g., retail incentives plus wholesale market revenues) for the same services. This principle is consistent with prior Board treatment of renewable incentives under N.J.S.A. 48:3-87. Storage incentives should be locationally targeted to areas where they can defer infrastructure investment, consistent with the Board's Non-Wires Alternatives ("NWA") framework recognized in the Grid Modernization Order at 20–23. Rate Counsel recommends:

[12] See In re Successor Solar Incentive Program, BPU Docket No. QO20020184, Order dated July 28, 2021 ("SuSI Order") at 28–32.
[13] See N.J.S.A. 48:3-60(a)(3) (requiring non-discriminatory treatment of customers).

- Explicit program spending caps;
- Periodic review and true-up mechanisms;
- Sunset provisions tied to market maturity.

iv. Phase 3 Initial Stakeholder Input

The Board should take the results from Phase 2 to develop an initial report to be disseminated to all stakeholders for their own analysis and comment. Like past initiatives, a public workshop with oral and written comment periods for all stakeholders should be part of this process. The Report and results should be provided in a way that identifies a clear set of actions that the Board may consider in developing a formalized set of rules and new regulatory guidelines.

v. Phase 4 Initial Straw Proposal

The Board should issue rules and provide a comment/input process consistent with past practices and the requirements of the APA. The Board's initial straw proposal should not merely identify conceptual policy directions, but should include sufficient specificity regarding proposed market structures, utility responsibilities, incentive mechanisms, cost recovery approaches, performance standards, and implementation timelines such that stakeholders can meaningfully evaluate the proposal's practical implications and likely ratepayer impacts. Stakeholders cannot reasonably provide informed comments on broad conceptual frameworks absent sufficient detail regarding the operational, financial, and regulatory consequences associated with the proposal.

The straw proposal should also clearly identify all anticipated utility expenditures, cost recovery mechanisms, and any proposed cost allocation methodologies between customer classes or participant and non-participant customers. To the extent the proposal contemplates utility ownership of DER assets, utility operation of aggregation platforms, utility administration of incentive programs, or utility investment in DERMS, AMI, telemetry, communications, or other

enabling infrastructure, the proposal should specifically articulate the legal, economic, and competitive rationale supporting such approaches.

In addition, the Board should provide stakeholders with access to all underlying modeling assumptions, avoided cost methodologies, load forecasts, hosting capacity assumptions, benefit calculations, and reliability analyses used to support the straw proposal. Transparency regarding analytical assumptions is critical to ensuring that stakeholders can independently evaluate whether the proposal is supported by substantial evidence and whether projected benefits are realistic, measurable, and achievable. The Board should also permit stakeholders sufficient time to conduct independent review and analysis of the straw proposal. Given the extraordinary complexity of DER/VPP market design issues, compressed comment schedules may materially disadvantage smaller stakeholders, consumer advocates, municipalities, and non-utility participants that lack the resources necessary to rapidly evaluate extensive technical proposals. Accordingly, Board Staff should provide adequate time for discovery, technical workshops, supplemental comments, and stakeholder responses prior to moving toward final recommendations.

Finally, the Board should ensure that the straw proposal clearly distinguishes between mandatory requirements, pilot program concepts, future areas for investigation, and provisions intended for later rulemaking or implementation proceedings. Absent such clarity, there is substantial risk that broad conceptual language may later be interpreted as implicit Board approval for expansive utility investments or market changes that were never fully vetted through the formal regulatory process.

vi. Phase 5 Final Proposed Recommendation

Final rules that reflect input should be prepared and sent to the Board for formal approval. Changes that have not gone through this vetting process should not make their way into any

recommendations. The final proposed recommendations submitted to the Board should include a comprehensive written explanation identifying how stakeholder comments, technical analyses, and evidentiary submissions were evaluated and incorporated into the final proposal. Where stakeholder recommendations are rejected, the Board or Staff should clearly articulate the factual, legal, economic, or policy basis supporting such determinations. Such transparency is essential to maintaining confidence in the integrity and objectivity of the regulatory process.

The final proposal should also include a clearly defined implementation schedule identifying which actions require immediate implementation, which actions should proceed through pilot programs or phased deployment, and which issues remain subject to future rulemakings, technical proceedings, or market design reviews. The Board should avoid approving overly broad or open-ended frameworks that delegate substantial unresolved policy matters to future administrative interpretation without additional stakeholder review and comment. In addition, final recommendations should include explicit affordability protections, cost containment provisions, and prudency review standards applicable to all future utility expenditures associated with DER/VPP implementation. Utilities should not receive blanket or automatic approval for future investments absent demonstrated need, measurable benefits, and continued evidentiary support. The Board should also reserve the ability to modify, suspend, or terminate programs that fail to produce demonstrated customer benefits or that result in materially higher-than-anticipated ratepayer impacts.

The final recommendations should further establish clear reporting obligations and performance metrics applicable to utilities, aggregators, and other participating entities. Such metrics should include customer participation levels, realized peak reduction performance, operational reliability impacts, verified customer savings, program utilization rates, dispatch

success rates, and actual versus projected cost-effectiveness outcomes. Ongoing reporting and periodic review are necessary to ensure continued accountability and to prevent programs from evolving into perpetual infrastructure spending initiatives unsupported by measurable results.

Finally, no major DER/VPP initiative should proceed to full statewide implementation until the Board has formally determined, based upon the evidentiary record developed throughout the proceeding, that the proposed actions are demonstrably necessary, reasonably cost effective, operationally achievable, competitively neutral, and in the overall public interest of New Jersey ratepayers.

For the foregoing reasons, Rate Counsel respectfully requests that in implementing the proposed Grid Modernization Plan the Board:

1. Require rigorous cost-benefit analyses;
2. Implement performance-based compensation structures at inception;
3. Prohibit double recovery and cross-subsidization;
4. Ensure transparency and accountability; and
5. Utilize pilot-based, phased implementation.

IV. Technical Tools to Facilitate Greater DER Interconnection

The Revised Notice seeks input from stakeholders on the DER interconnection improvement filings sought from the EDCs. Rate Counsel encourages the New Jersey EDCs to leverage the experiences and best practices from other states in order to formulate solutions that maximize the number of DERs which can be interconnected to the distribution system while minimizing the ratepayer costs of doing so. Rate Counsel believes that Board Staff and the EDCs consider the following recommendations as they continue to develop their interconnection guidelines.

a. "Grouping" DER interconnection studies and managing application queues

DER interconnection studies are a necessary responsibility of each EDC to ensure the safe, reliable operation of their distribution system. The time associated with completing such studies is often cited as an obstacle and hurdle by DER developers. Each individual utility-scale interconnection request requires utilities to complete individual DER interconnection studies. As the number of requests for DER interconnection increase, completing the additional volume of applications becomes burdensome to EDCs and time consuming for developers, delaying the addition of beneficial generating assets to the grid.

To assist in managing the application queue, it may be possible to group application studies. This process has been demonstrated in Massachusetts where utilities group several interconnection requests together to complete a single DER interconnection study covering multiple requests. Regulations cover application windows, request abdication, and similar issues. Additionally, utilities may also consider if using contract engineering to complete the studies in accordance with utility practices would present a time and cost saving opportunity.

Rate Counsel believes that the DER developer community should also be held accountable in helping manage the application queue. BPU should not waive the requirement that level 3 applicants pay for the full cost of interconnection studies necessary to proceed with their applications. The BPU should consider removing the application fee cap and replace it with historic, actual costs incurred to process a level 3 applications. DER developers may clog interconnection queues with speculative projects. To discourage this, it may be better practice to require developers to demonstrate site control (ability to build on the designated DER site) before the EDC commits to undertaking costly and time-consuming grid analysis.

b. Identifying attractive zones for distribution capacity expansion

Distribution spending to accommodate multiple, far-flung, utility-scale DER interconnection requests is costly. Consolidating distribution (sub transmission) capacity expansion into a smaller number of circuits could ultimately prove less costly to the EDC and their ratepayers. Utilizing informal working groups of developers, government entities, and utilities to identify attractive zones for DER development is one approach. It is Rate Counsel's understanding, that this concept is being used in Virginia where DER developers are working with utilities and government entities to identify zones into which circuit capacity expansion spending may be consolidated.

c. Using fewer conservative approaches to determine hosting capacity limits

It is unclear how EDCs determine hosting capacity as the concept is not clearly defined. Rate Counsel encourages the Board to require utilities to explain how hosting capacity limits are calculated. Notwithstanding, it is Rate Counsel's understanding that utilities may establish hosting capacity limits by identifying reverse power flows, and that utilities may be able to identify reverse power flow by examining a circuit's minimum loads, or other system concerns. For these utilities, minimum loads occur during early morning hours on weekends in the spring or fall. This is a period when the sun is not shining and therefore would not be impacted by solar generation.

Solar production is highest during the hours around noon, when circuit loading is generally greater than the early morning, weekend minimum. Thus, examining a circuit's minimum loads *at noon* would result in a less conservative approach to identifying reverse power flow and would establish more appropriate hosting capacity limits.

The resulting increased hosting capacity limits will allow the interconnection of additional DERs without having to complete costly, and potentially unnecessary, grid upgrades.

d. Flexible interconnections and the use of energy storage systems (ESS)

Rate Counsel understands that flexible interconnections can increase overall hosting capacity by allowing the EDC to curtail a portion of DER output when generation exceeds the circuits allowable hosting capacity. Although curtailing generation can negatively impact the DER developer, financially viability may be possible if the curtailments are forecasted to be infrequent or minimal.

Allowing for flexible interconnection requires the EDC to have real time visibility into their distribution system and a means to communicate with and controls DERs, such as DERMS. Many EDCs are beginning to experiment with flexible interconnections and should be encouraged to more fully adopt such technology. However, it is important that policy considerations are addressed to ensure curtailments are administered fairly amongst interconnected DERs.

The use of energy storage systems (batteries) can also increase hosting capacity on certain circuits. Utilities should evaluate whether batteries can be a cost-effective remedy for capacity limits.

e. Data-driven decision making on DER-driven grid modernization

Utilities are responsible for providing safe and reliable service and are therefore appropriately concerned about DER-driven risks of islanding (safety) and power quality (voltage and frequency). However, it is possible that utilities are being overly conservative. IEEE-1547 is the technical standard established by the Institute of Electrical and Electronics Engineers to govern the interconnection of DERs. Due to utilities and developer's adherence to this standard, Rate Counsel is unaware of actual islanding incidents, and DER-related power quality incidents are exceedingly rare. Moreover, research indicates the conditions likely to result in unintentional

islanding are exceedingly rare.[14] Since hosting capacity limits and equipment policy decisions prompt distribution spending, the Board should require utilities to present data and research in support of equipment replacement project or equipment policy decisions.

f. Establishing DER Export Tariffs and Line Extension Policies

The distribution (sub-transmission) grid is essential to getting DER products (energy and capacity) to market. This infrastructure costs money to construct, expand, maintain, and operate. It is only reasonable to expect DER developers using this infrastructure to get their product to market to be responsible for covering their share of these costs.

Rate Counsel recommends that the Board should consider requiring all utilities, in their next base rate cases, to establish 'DER designed for export' as a customer class in class cost of service studies, and to create export tariffs, including ongoing charges for capacity (kW) and energy (kWh) transportation based on those CCOSS.

Similarly, as required with new customer loads, the Board should establish a line extension policy which utilities must use to determine the share of connection costs each new DER designed for export should be required to pay up-front.

g. Examining PJM interconnection hosting capacity limits and DER interconnection requests as a potential part of the problem

When PJM establishes hosting capacity limits that are needlessly conservative, or when PJM takes inordinate time and cost to evaluate DER interconnection requests, developers naturally look to distribution utilities to accommodate their proposed projects.

[14] Ropp M, Ellis A. Suggested Guidelines for Assessment of DG Unintentional Islanding Risk. Sandia National Laboratory Report SAND2012-1365. February, 2012.

Upgrading distribution (sub-transmission) circuit capacity to accommodate projects may be more costly than interconnecting to PJM transmission. Avoiding PJM constraints or delays may not represent an appropriate justification for costly distribution circuit capacity upgrades.

Rate Counsel recommends the Board take steps to gather information and understand how PJM establishes hosting capacity limits, and how PJM processes interconnection requests, and pursue appropriate modifications designed to reduce the pressure to complete distribution grid capacity increase projects that might not represent cost-effective ways to accommodate DER (and especially DER designed for export).

h. Requiring Cost-effectiveness tests at a system-wide level

BPU Staff seems to assume that adding DER capacity is the answer to high costs at the wholesale level. This should not be assumed, because costs to accommodate DER capacity are being incurred beyond the wholesale (transmission) infrastructure level.

Upgrading distribution (sub-transmission) circuit capacity, and implementing DER-related grid modernization equipment policies, are extremely costly endeavors. As set forth in the discussion on BPU's process, the Board should require cost-effectiveness tests that consider system-wide DER costs as well as system-wide DER benefits.

V. Responses to EDC and Stakeholder filed comments

Rate Counsel has reviewed the comments submitted by stakeholders in response to this Request for Information and submits the following responses.

With respect to Public Service Electric and Gas Company, PSE&G provides several general comments. PSE&G advocates for proactive spending on circuit reinforcements to accommodate additional distributed energy resource management systems. However, Rate Counsel recommends that PSE&G should first determine how to optimize existing circuit capacity before requesting

additional investments to be funded by ratepayers. Rate Counsel further recommends that traditional utility investment in wires should not be the default approach, but should be used only when it has been determined to be cost-effective in comparison to other available solutions.

Rate Counsel does not disagree with PSE&G's assessment that multiple existing and competing initiatives should be aligned, including virtual power plant and distributed energy resource integration policies, FERC Order No. 2222, Executive Orders Nos. 1 and 2, the Triennium, the GSESP, the Proactive System Upgrade Plan, the Demand Response Roadmap, electric vehicle plans, and advanced metering infrastructure data access. Rate Counsel observes that if these initiatives are not rolled out in a comprehensive and thoughtful manner, their implementation could result in unnecessary, additional costs to ratepayers. Rate Counsel recommends that the Board enforce prudent cost-benefit analysis practices for any proposed utility investment that may impact ratepayers.

Additionally, Rate Counsel agrees that the N.J.A.C. 14:8-5.13 mandate requiring electric distribution companies to enter into a joint contract with all other electric distribution companies and a third-party developer to create a common interconnection application process portal may be challenging. It is imperative, however, that customers and developers have an easily accessible portal to facilitate distributed energy resource interconnection.

Rate Counsel also considers that EDC investment in energy storage may be appropriate if such a solution is shown to be cost-effective as compared to alternative solutions, including investments by private distributed energy resource developers in energy storage. Regarding Section A, Compliance with N.J.A.C. 14:8-5, Rate Counsel recommends that PSE&G should accelerate portal development or identify an alternative method to accommodate the pre-application verification and evaluation process requirement, as pre-application information

will help reduce overall application processing time. Regarding Section B, BPU regulations inhibiting distributed energy resource interconnection, Rate Counsel notes PSE&G's identification of administrative issues that may make application and administration cumbersome, including the joint portal contract, hosting capacity maps, and billing developers for incurred costs. Rate Counsel does not believe any of these issues would actually inhibit or prevent distributed energy resource interconnection.

Regarding Section D, Identifying constrained circuits, PSE&G identifies circuits closed to new distributed energy resource interconnection due to thermal, voltage regulation, or system protection constraints and states it is considering traditional system investments to increase hosting capacity. Rate Counsel recommends that before such investments are made, PSE&G should review Rate Counsel's recommendations of technical tools to facilitate greater distributed energy resource interconnection to ensure that more cost-effective approaches have been examined. Rate Counsel agrees that focusing on the poorest circuits, in terms of hosting capacity, may not be as advantageous as concentrating on circuits where distributed energy resources are most likely to be developed and refers Board Staff to Rate Counsel's comments above on grouping distributed energy resource interconnections.

Regarding Section E, Other means of supporting distributed energy resources on constrained circuits, PSE&G's proposal to codify flexible interconnection protocols through a stakeholder process may be a reasonable approach, provided it complies with the notice and comment requirements of the APA.

With respect to JCP&L, the company states in its general comments that it will incur substantial additional costs to comply with the requirements in the distributed energy resource interconnection rule changes and that it will seek to recover those costs from customers. Rate

Counsel does not adhere to the assumption that incorporating more distributed energy resources will automatically cause JCP&L to incur additional costs. Rate Counsel states that, should additional costs arise, the applicability of such costs and the corresponding benefit to customers must be demonstrated before seeking recovery from ratepayers through the traditional ratemaking process or through the Infrastructure Investment Programs.

Regarding Section A, Compliance with N.J.A.C. 14:8-5, JCP&L states it is working toward meeting compliance with the requirements. Rate Counsel is not convinced of the usefulness of EDC and stakeholder-convened workgroups to promote consistency across EDC in complying with the regulations. In Section D, Identifying constrained circuits, JCP&L identifies circuits closed to new distributed energy resource interconnection due to reverse power flow. Rate Counsel believes that it is possible that some of these limitations are due to overly conservative limitations, as discussed in Rate Counsel's section on hosting capacity limits.

Regarding ACE's comments, Rate Counsel agrees that in certain circumstances it may be necessary to perform additional system analysis on energy storage systems, specifically those operating in parallel with the distribution system. In Section D, Identifying constrained circuits, ACE identifies circuits closed to new distributed energy resource interconnection due to reverse power flow. In response, Rate Counsel refers to its discussion of the possibility of overly conservative hosting capacity limitations in its technical tools section.

Regarding RECO, the company states that it is undertaking a distributed energy resource management systems demonstration project that will inform its evaluation of flexible interconnection strategies and their potential integration into the distribution system. Rate Counsel encourages RECO to share the results, when available, with the other New Jersey electric distribution companies, Board Staff, and Rate Counsel so that such shared knowledge may have

meaningful impact on reducing the costs of distributed energy resource interconnection for all New Jersey ratepayers.

Rate Counsel also responds to comments submitted by additional stakeholders. The League of Conservation Voters introduces the concept of pursuing distributed energy resource interconnections at points where existing interconnections have surplus capacity, such as existing power plants operating under capacity. Rate Counsel recommends that, to the extent possible or advisable, EDCs should be encouraged to indicate such interconnection points on their hosting capacity maps. Rate Counsel concurs with the League of Conservation Voters that low-income ratepayers must be protected and that, to protect all ratepayers, EDCs must demonstrate that appropriate cost-benefit analysis has been conducted and that benefits attributed to investments are clearly shown for all customers.

In response to comments submitted by the Mid-Atlantic Solar & Storage Industries Association, Permit Power, and Vote Solar, Rate Counsel agrees that electric distribution companies should re-evaluate assumptions regarding limitations on the amount of distributed energy resources a circuit can handle, using real-world experiences from Hawaii, California, and other jurisdictions with high concentrations of distributed energy resources. Rate Counsel also recommends that EDCs should evaluate the recommendations regarding the use of smart inverter settings. Rate Counsel does not disagree with the recommendation to evaluate flexible interconnection while recognizing that policy will need to be developed to allow for fair administration of curtailment controls. Rate Counsel further recommends that ACE and other electric distribution companies should validate whether the assertion that reverse power flow constraints can be mitigated at low relative cost is accurate.

Finally, Rate Counsel responds to comments submitted by the New Jersey Environmental Justice Alliance. Rate Counsel agrees that programs should encourage equity but states that it has concerns that certain requirements may increase cost without increasing access to underrepresented groups. Rate Counsel recommends that the adoption of additional requirements should be based on sound data indicating that any additional costs incurred are justified.

Respectfully submitted,

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DW/dl
No enclosure