Environmental Defense Fund

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VIA DMM

Hon. Michelle L. Phillips
New York Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: Matter No. 24-E-0364 – In the matter of Proactive Planning for Upgraded Electric Grid Infrastructure

Dear Secretary Phillips:

Environmental Defense Fund hereby submits for filing in the captioned docket these Comments of Environmental Defense Fund on the Joint Utilities' Long-Term Proactive Planning Framework, in response to the January 29, 2025, New York State Register Notice. Pursuant to this notice, these comments are timely filed on March 31, 2025.

Respectfully submitted,

Michael Zimmerman

COMMENTS OF ENVIRONMENTAL DEFENSE FUND ON THE JOINT UTILITIES' LONG-TERM PROACTIVE PLANNING FRAMEWORK

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I. **Introduction**

This proceeding presents the New York State Public Service Commission ("Commission") with the opportunity to establish a Proactive Planning Framework ("Framework") that will improve infrastructure planning by facilitating achievement of New York's electrification targets while also incorporating guardrails to protect customers. While the Joint Utilities' ("JU") proposed Framework presents a strong foundation, modifications are still required to ensure that the Commission achieves its stated objectives of "avoid[ing] inefficient or redundant investments and significant delays to New York's efforts to electrify the transportation and building sectors."[1] To this end, the Commission should adopt the recommendations offered by the Environmental Defense Fund ("EDF") in these Comments.

Distribution planning must continually evolve as technology, policy, and grid needs change. Sales of electric heat pumps overtook those of gas furnaces in 2022—before federal tax incentives were available – and extended their lead in 2023.[2] Electric vehicles continue to grow as a proportion of new vehicle sales,[3] and the New York Independent System Operator ("NYISO") projects transportation electrification to add over 6 TWh of electric consumption between 2025 and 2030.[4] These trends will continue as New York implements the requirements set forth in the Climate Leadership and Community Protection Act ("CLCPA"),[5] New York's all-electric buildings law[6] and companion building code, and New York City's Local Law 154.[7] Electrification of the building and transportation sectors stands to bring billions of dollars of benefits, including public health improvements.

The Commission can more swiftly unlock these benefits by adopting a sound Framework to guide utilities' infrastructure investments needed for electrification. Broadly speaking, a successful Framework will: (1) ensure planning coordination among and across proceedings; (2)

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[1] Case No. 24-E-0364, *In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure*, Order Establishing Proactive Planning Proceeding at 4 (Aug. 15, 2024) [hereinafter "Proactive Planning Order"].

[2] Allison F. Takemura, Canary Media, *Heat pumps outsold gas furnaces again last year – and the gap is growing*, https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing (Feb. 13, 2024).

[3] *See* Kelley Blue Book, *Electric Vehicle Sales Report – Q3 2024* , https://www.coxautoinc.com/wp-content/uploads/2024/10/Kelley-Blue-Book-EV-Sales-Report-Q3-2024-revised-10-14-24.pdf (Oct. 14, 2024).

[4] Max Schuler, NYISO, *2024 Electric Vehicle Forecast Update* , https://www.nyiso.com/documents/20142/43675604/04_20240321_ESPWG_EV_Forecast_V1.pdf/36b1e462-99c9-14f8-ebb1-d9a8680b4936 (Mar. 21, 2024).

[5] Climate Leadership and Community Protection Act, 2019 N.Y. LAWS 106.

[6] S4006c/S3006c (2023).

[7] Local Law No. 154 (2021) of City of New York.

promote utility accountability through granular assumptions and well-defined scenarios; (3) preserve appropriate opportunities for stakeholder input; (4) promote efficient and transparent cost recovery; and (5) allow for iteration and encourage ongoing improvement.

As EDF details herein, the Commission should direct several modifications to the Framework, including by:

- Prioritizing utilities' rate cases as the preferred venue to review anticipated capital investment (*see* Sections II, III.D.4);

- Ensuring productive coordination between the proactive planning proceeding and the Coordinating Grid Planning Process ("CGPP") and utilities' Distribution System Implementation Plans ("DSIP") (*see* Sections III.C.1, III.C.3);

- Requiring that State policy compliance should not only be a consideration, but the <u>baseline</u> assumption of the utilities' efforts (*see* Sections III.A.1, III.A.2);

- Directing utilities' load assessments to incorporate: a long-term forecasting horizon, forecasts rooted in location-specific methodologies, robust scenario analysis, policy compliance underpinning the baseline planning scenario, and robust stakeholder engagement from the outset (*see* Section III.D.1);

- Ordering the utilities to adopt clear metrics to guide and evaluate investment decisions and more systemically consider alternative solutions such as load flexibility, energy, storage, and Non-Wires Alternatives ("NWAs") (*see* Section III.D.2);

- Directing modifications to the proposed surcharge to facilitate customer benefits, including explicitly incorporating incremental revenues and cabining the surcharge to those investments consistent with the utility's DSIP (*see* Section III.D.4.iii);

- Rejecting the JU Framework's proposed "Large" and "Small" project categories and corresponding separate budgeting process for "Small" projects because this structure is unnecessary, lacks definition, and falls short on procedural protections (*see* Section III.D.4.iii);

- Creating meaningful opportunities for community engagement by promoting procedural justice and ensuring utility accountability through clear metrics and robust reporting requirements (*see* Section III.E); and

- Directing utilities to file periodic reports to track projects approved for interim cost recovery (*see* Section IV.A).

II. General Recommendations

EDF's comments on the Framework are grounded in its position that "proactive planning" <u>is planning</u>. Utilities have always sought to predict and prepare for future loads. And the existing regulatory paradigm provides for utilities to invest, with a commercially-acceptable level of risk, in projects they reasonably deem necessary to serve those loads. Emerging electrification loads have unique characteristics that warrant individualized attention, but they need not break this paradigm. "Proactive planning" should mean updating existing processes and standards to keep pace with emerging ahistorical load sources and changing customer expectations.

This approach, favoring "evolution over revolution," carries several advantages. It allows for more application of established Commission precedent, reducing the need to invent (or reinvent) processes. It should afford more predictable and durable substantive outcomes—which, in turn, should reduce perceived regulatory risk (and corresponding financing costs) over time. It also reflects the reality that the grid is an integrated, multi-purpose machine serving a wide range of end-uses; utilities should not plan around select end-uses in a vacuum.

EDF therefore urges the Commission to prioritize utilities' rate cases as the preferred venue to review anticipated capital investment, and to clearly circumscribe the scope and purpose of parallel processes as conceived in the draft Framework. Rate cases provide a venue for comprehensively reviewing utilities' forecasted spending and revenues, including the myriad factors beyond capital expenditures that inform rate-setting. The utilities' own Urgent Need filings illustrate the value of reviewing these factors together. For example, as EDF observed in its comments on those filings, NYSEG/RG&E's request for cost recovery of its Urgent Need projects had more to do with the Companies' financial health—which is a matter suited for rate case review—than the projects themselves.[8] Rate cases also enjoy well-established procedural rules, including processes for conducting discovery, submitting and examining testimony, and resolving procedural disputes.[9] Such rules help safeguard due process rights of all parties, support the development of robust factual records, and promote transparent outcomes.

EDF acknowledges that emerging loads pose novel planning opportunities and challenges, and agrees that New York's existing rate case paradigm, on its own, has struggled to keep up. The

[8] Case 24-E-0364, *In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure*, Comments of Environmental Defense Fund on the Proactive Planning Upgrade Projects Evaluation and Funding Proposal and Urgent Upgrades Proposals, at 43-44 (Mar. 10, 2025) [hereinafter "EDF Urgent Needs Comments"].
[9] *See generally* 16 NYCRR ch I.

Framework should address these challenges in three ways. First, it should mitigate actual risk. The Framework should encourage utilities to identify, implement, and improve planning best practices, such that these novel load sources are eventually baked into system planning (and addressed through projects addressed as part of rate cases) as a matter of normal course. Adjustments to utilities' Distribution System Investment Plans can support this end, as discussed in Section III.C.3 herein. Second, the Commission should mitigate residual *perceived* risk. The JU's proposed Framework and Utilities' urgent need filings suggest that they may be reluctant to invest in anticipation of ahistorical loads, absent some additional regulatory certainty. EDF does not believe it is appropriate to immunize projects against rate case review, as the JU appear to propose.[10] Instead, the Commission can clarify that projects developed consistent with identified best practices enjoy a presumption of prudency, placing them on an equal footing with other projects proposed as part of rate cases. Third, for a transitional period, the Commission should allow limited interim cost recovery for projects that cause a utility to exceed its then-authorized revenue requirement.

III. Comments on the Joint Utilities' Proposed Framework

The JU's proposed Framework would establish review and cost recovery procedures for each "Large" project and "Small" project portfolios. Large projects would be subject to a four-stage planning and review process that would run iteratively on a fixed annual cycle.[11] Each cycle would include activities related to load forecasting; solution planning, design, and prioritization; and stakeholder engagement; and would culminate in Commission review of project proposals, after which the utility would presumably commence construction of "approved" projects.[12] The Framework would also establish a separate iterative process for utilities to establish biennial budgets for Small projects.[13] Small project portfolios would "operate[] in the same way as a programmatic budget," and utilities would deploy Small projects according to a Commission-

[10] Case 24-E-0364, *In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure*, Joint Utilities' Long-Term Proactive Planning Framework at 33 (Dec. 13, 2024) [hereinafter "JU Framework"].
[11] *Id*. at 5 ("This process includes four stages: (1) load assessment; (2) planning and solution design; (3) project eligibility and prioritization criteria; and (4) proposal and authorization of eligible projects. Together, the four stages comprise the Proactive Planning process 'Cycle'").
[12] *Id.* The JU Framework does not specify the stage of development at which a "Large" project would be reviewed, but it appears to contemplate an early pre-construction stage. *Id.* at 32 ("Without timely and appropriate approval, utilities may not be able to **start development** for these electrification projects") (emphasis added).
[13] *Id.* at 10.

approved plan established on a biennial cadence.[14] The Framework also proposes allowing utilities to recover costs of Large and Small projects through company-specific surcharges, which would be rolled into base rates at each utility's base rate case.[15]

EDF's following comments are organized according to the JU's Framework.

A. <u>Introduction and Guiding Principles</u>

1. Guiding Principles

The JU Framework identifies five guiding principles. EDF addresses each of these principles below.

Support customer needs in a timely manner without adverse impacts

The JU state that the proactive planning process "must account for the inherent timing mismatch where customer electrification loads seek to be added to the grid in just months, while buildout of the grid to support these loads can take up to ten years."[16] EDF agrees. As demonstrated by the Urgent Needs Filings of Con Edison, National Grid, and NYSEG/RG&E, many of the grid upgrades needed to serve new load, including TE and BE load, can be complex projects that span not just multiple years but also multiple rate plans.[17] While there are some things utilities can do to shorten these timelines—e.g., standardizing designs, increasing staffing, and improving asset procurement—they also face competing factors including long lead times for transformers and other electrical equipment and a shortage of qualified electricians.[18] Proactive planning helps to address these upward pressures on timelines by allowing utilities to more confidently begin needed projects sooner, reducing the likelihood of adversely impacting customers through interconnection delays.

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[14] *Id.* at 31.
[15] *Id.* at 33.
[16] *Id.* at 3.
[17] Case No. 24-E-0364, *In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure*, National Grid Urgent Upgrade Projects at Appendix 4 (Nov. 13, 2024) [hereinafter "National Grid Urgent Needs Filing"]; Consolidated Edison Company of New York, Inc. Urgent Projects Proposal at 21 t.2 (Nov. 13, 2024) [hereinafter "Con Edison Urgent Needs Filing"]; Petition of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation for Approval of Urgent Upgrade Projects and Associated Cost Recovery at 20 t.1, 22 t.2 (Nov. 26, 2024) [hereinafter "NYSEG/RG&E Urgent Needs Filing"].
[18] *See* National Infrastructure Advisory Council, *Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the U.S. Power Grid* (June 2024), https://www.cisa.gov/sites/default/files/2024-09/NIAC_Addressing%20the%20Critical%20Shortage%20of%20Power%20Transformers%20to%20Ensure%20Reliability%20of%20the%20U.S.%20Grid_Report_06112024_508c_pdf_0.pdf.

Support achievement of objectives in policies, laws, and regulations

The JU state that the proactive planning process "should enable the expected accelerated customer adoption of electrification to achieve ambitious State and local policy goals and regulatory compliance."[19] They point to state regulations including Advanced Clean Cars II ("ACC II") and Advanced Clean Trucks ("ACT"), as well as local laws including Local Law 154 and Local Law 97 in New York City.[20] EDF agrees with this principle, and would modify it to clarify that the utilities' efforts, as part of the proactive planning process and in their forecasting and planning generally, <u>must</u> enable compliance with these goals and regulatory requirements. As discussed further in Section III.D.1 below, robust scenario planning should be a core component of the distribution planning, and achievement of state policy must be the baseline of those scenarios.

Cost efficiency

EDF agrees with the JU's position that "[p]lanning approaches and solution designs should seek to maximize the value of grid investments and manage risks related to over- or under-building."[21] These risks are asymmetric. Overbuilt infrastructure can lead to higher ratepayer costs, but this risk can be mitigated as the availability of excess grid capacity can attract new customers to an area. There are real-world examples of this dynamic already playing out in New York.[22] EDF's study with Black & Veatch, discussed further below, also suggests that the harm from planning proactively will often be less than a business-as-usual approach.[23] The utilities can also further mitigate this risk by working closely with customers, local governments, and state agencies to understand how customer plans, land use plans, and state policies will affect and be affected by the utilities' grid buildout efforts.

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[19] JU Framework at 3.
[20] *Id.* at 3 n.3.
[21] *Id.* at 4.
[22] Case No. 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure*, Revel Comments in Response to the Electric Vehicle Make-Ready Program Midpoint Review and Recommendations Whitepaper, at 2 (May 15, 2023) ("Most of the early sites we developed did not require power upgrades. However, such locations with enough electrical capacity and good public vehicle access are few and far between, meaning more future sites will require power upgrades."); Case No. 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure*, EV Make-ready Program (MRP) Midpoint Review Kick-Off (Sept. 20, 2022) (stating that 96% of fleets that had reached out to their utility were ineligible for the MHDV make-ready pilot, with lack of utility-side upgrade needs being a common reason).
[23] EDF and Black and Veatch, *Proactive Grid Investment: Medium- and Heavy-Duty Vehicle Transportation Electrification*, https://www.edf.org/media/new-study-suggests-preparing-grid-now-electric-trucks-buses-can-save-ratepayers-money (Nov. 6, 2024).

In contrast, the potential risks of underbuilding are broader in their scale and types of harm. Underbuilt assets can require sequential upgrades that increase ratepayer costs.[24] The lack of sufficient grid capacity can also slow the electrification of customers seeking interconnection, including those facing regulatory compliance deadlines or otherwise covered by state policy goals. This means greater societal harms including increased greenhouse gas emissions and local air pollution, which disproportionately harms disadvantaged communities ("DACs"). It can also mean financial harm for customers facing penalties for not meeting compliance deadlines. Finally, insufficient grid capacity can dissuade economic development including new housing construction and new and expanded businesses, threatening New York's economic competitiveness.

The JU Framework points to several tools to minimize over- and under-building risks, including investing in least-regrets areas, using phased and expandable asset designs, and using advanced technologies.[25] EDF generally agrees with these, but more can be done. As discussed in Section III.D.2 below, the current process for identifying and implementing non-wires alternatives does not adequately account for the tools available today to mitigate and avoid grid upgrade needs. The utilities' forecasting and planning processes must begin to include reasonable assumptions regarding managed charging, which have already shown success in shifting charging to off-peak periods but are not yet meaningfully incorporated into the utilities' forecasting assumptions. And the utilities should incorporate emerging tools to enable load flexibility, such as flexible interconnection policies, to shorten interconnection timelines and increase system utilization to the benefit of ratepayers. As explained below, EDF is concerned that load flexibility issues are being siloed in the Grid of the Future proceeding to the effect of insufficiently incorporating potential solutions as part of the proactive planning process. To realize its full potential for mitigating distribution system costs, meaningful assumptions for load flexibility must be incorporated into this process.

Flexible planning and authorization

The JU state that "[p]lanning and regulatory processes should accommodate fast-evolving markets and policies by balancing a nimble and agile process with appropriate guardrails."[26] EDF

[24] *Id.* at 7 ("Proactive planning for M/HDV electric load can result in capital expenditure (CAPEX) savings in the long run due to reduced need to upgrade the same station to accommodate load growth into the future, when compared to sequential planning approaches.").
[25] JU Framework at 4.
[26] *Id.*

agrees, but the proposed JU framework may have the effect of decreasing, rather than increasing, their flexibility to complete necessary system investments to serve electrification load. The JU describe the framework as "designed to support statewide coordination for forecasting, planning, evaluation, and approval of investments to support timely and efficient infrastructure buildout to enable electrification."[27] But as stated above, the Commission has made it clear that its role is to regulate the cost recovery of utility investments, not to approve or deny the construction of specific distribution projects. Creating a new regulatory process between individual utility rate cases that relies upon Commission approval of specific projects would complicate utilities' discretion to make needed investments. The utilities generally already have the discretion to shift funds within their approval capital plans to high-priority projects, even if those projects were not contemplated when those capital plans were developed.[28] There is no reason to upend that process here. The Commission has a critical role to play in regulating utilities' overall spending and the prudency of those investments the utilities choose to make. That should remain its focus here.

Complement other regulatory processes

EDF agrees with the JU that a proactive planning process should "effectively coordinate with other regulatory proceedings in a way that either enhances or does not interfere with those processes, without adversely impacting the objectives of Proactive Planning."[29] This does not, however, mean that an entirely new project proposal and approval process is necessary to effectuate proactive planning. Implementing proactive planning should, at its core, mean updating utilities' forecasting and planning methodologies to better prepare for anticipated electricity demand—including but not limited to electrification—over a longer time horizon. Interim cost-recovery will be appropriate in some instances, and load growth-driven system needs may be well-suited to this given the potential for incremental revenues to offset system costs. But this can be

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[27] *Id.* at 11.

[28] *See, e.g.*, Case No. 22-E-0064, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Joint Proposal, at 20 (Feb. 16, 2023) ("The Average Electric Plant In Service Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Electric Rate Plan to modify the list, priority, nature and scope of its capital programs and projects."); Case No. 20-E-0380, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, Joint Proposal, at 39 (Sep. 27, 2021) ("Notwithstanding the specified segment-level spending amounts set forth in Appendix 1, Schedule 5, nothing in this Joint Proposal is intended to limit Niagara Mohawk's flexibility during the term of the rate plan to substitute, change, or modify its capital projects.").

[29] JU Framework at 4.

accomplished through more modest changes than what the JU Framework proposes without upending the rate case process.

2. Scope of Proactive Planning Proceeding

The JU Framework also proposes three constraints on the scope of the proactive planning process: electrification scope, policy scope, and planning scope.

Electrification Scope

The JU's proposed electrification scope includes transportation electrification, building electrification, and all other electrification.[30] This broad definition is appropriate. While there may be unique assumptions and data sources that are appropriate for specific types of electrification load, utilities' forecasting and planning processes should not create disconnected processes for preparing for and serving specific types of loads.

For this same reason, however, it does not make sense from a utility planning and operations perspective to create separate review processes for grid investments driven by electrification loads than those processes used for other system investments such as asset life projects, reliability projects, and CLCPA-driven projects. The utilities should be considering how they account for electrification in their forecasting and planning efforts, but their investment decision should be driven by a process that considers and prioritizes system needs holistically rather than isolating different categories of projects. EDF's proposed surcharge mechanism, described further below, takes this holistic approach.

Policy Scope

EDF supports the JU's position that the Framework "consider full State policy compliance with any near-, mid-, or long-term regulations and goals"[31] but reiterates that State policy compliance should not only be a consideration, but the <u>baseline</u> assumption of the utilities' efforts. Additional scenarios or sensitivity analysis may be appropriate to understand what impact failure to achieve state policy goals would have on grid needs, but enabling achievement of these goals should be the default for forecasting and planning purposes.

Planning Scope

The JU state that its planning efforts for the proactive planning process "are expected to identify needs with greater granularity than processes in other proceedings."[32] This framing

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[30] *Id.* at 4-5
[31] *Id.* at 5.
[32] *Id.*

implies that the utilities' proactive planning efforts may occur separately from their forecasting and planning efforts generally, or those tied to other proceedings. As explained throughout these comments, implementing proactive planning should primarily mean improving the utilities' forecasting and planning methodologies to more accurately forecast expected electricity demand and prepare accordingly. The more granular forecasts the utilities develop through the implementation of a proactive planning framework should inform the utilities' work generally, including in rate case applications and generic proceedings.

B. Summary of Proactive Planning Framework

EDF has no comment on this section of the JU Framework.

C. Coordination with Other Proceedings

1. Coordination with CGPP

Coordinating the JU Framework with the utilities' proactive planning efforts and the Coordinated Grid Planning Process ("CGPP") will help fill current identified gaps and lead to better standardized processes. The Commission's original intent for the CGPP was to develop a uniform process for the utilities to identify "projects on the distribution and local transmission systems that support achievement of CLCPA goals."[33] However, the CGPP's efforts to date have been limited to bulk power system needs, with less focus on distribution-level investments. Proactive distribution planning can address this gap by strengthening and standardizing the utilities' assumptions regarding electrification load and their corresponding system planning. EDF agrees that the CGPP should incorporate the "assumptions and outputs" from the proactive planning process, so long as the inputs and assumptions for the proactive planning process are consistent with achievement of state policy and regulatory requirements.[34]

How CGPP develops its forecasts is out of scope of this proceeding. There are, however, several decisions the Commission can make in the instant proceeding to ensure productive coordination between proactive planning and the CGPP. The Commission should identify and order the utilities to take the necessary steps to successfully implement such application of load forecasting results into the CGPP. As discussed below, proactive planning should employ at least

[33] Case No. 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Order Approving a Coordinated Grid Planning Process, at 2 (Aug. 17, 2023).
[34] JU Framework at 12.

three scenarios, which the utilities can align with the three scenarios used for the CGPP.

The Commission should also clarify that the coordination between the proceedings is focused on forecasting, not solution identification. The JU Framework states that the CGPP "will only include Commission-approved Proactive Planning projects in its processes."[35] This conflates load forecasts and solutions. CGPP should incorporate all appropriate bottom-up forecasts developed by the utilities, irrespective of the utility's preferred solution or where that solution is identified (i.e., within a rate case application or with a separate proactive planning process). Finally, the Commission should ensure that the utilities' proactive planning process—in particular the publication of the results of that process—is timed to easily feed into the corresponding steps in the CGPP.

2. Coordination with Rate Cases

The JU's proposal would create a proactive planning process that is unreasonably divorced from the rate case process. The JU Framework exaggerates the gap between rate cases, stating that they "typically span five years"—i.e., a three-year rate plan with two preceding years of forecasting and planning.[36] While it may be true that the forecasting work that informs a utilities' rate case filing begins two years before it makes that filing, the relevant timespan is from the beginning of one forecasting cycle to the beginning of the next. And while even a three-year gap may be too long for utilities to sufficiently anticipate needs driven by electrification, this does not itself require the creation of an entirely new, overlapping, vaguely-defined regulatory process to address it.

Utilities already have flexibility regarding how they allocate their capital budgets. The fungibility of utilities' capital budget is routinely provided for in rate cases, and used by those utilities to move funds around to cover high-priority projects.[37] There is already evidence of this activity in the record of this proceeding. For example, Con Edison explained as part of its urgent needs filing how it moved funds within its capital budget to serve higher than anticipated new business expenses within its current rate plan.[38] It also is not obvious why the JU's proposed proactive planning process is necessary or appropriate for electrification-driven capital costs in particular, as other factors can drive similarly high-priority needs. An unexpected asset

[35] *Id.* at 12 n.25.
[36] *Id.* at 11.
[37] *See supra* note 28 and accompanying text.
[38] *See* Con Edison Urgent Needs Filing at 16-17.

replacement need driven by a shorter-than-forecast asset life can show up in a way not accounted for in a utility's rate plan and still require investment. Utilities' obligation to serve customers and to maintain a safe and reliable system requires prioritization of decisions regularly.

Divorcing the proactive planning process from utilities' rate cases could also weaken oversight of utilities' investments by the Commission and Staff, as well as stakeholder engagement. Rate cases are opportunities for the Commission, Staff, and other interested parties to comprehensively study details of utilities' prior, ongoing, and anticipated investments. The JU's proposed proactive planning process would effectively create a separate miniature rate case that would see final Commission action within 120 days of filing,[39] compared to the current rate case process that can take more than one year.[40] Interested parties also may not have the capacity to engage in both a utility's rate case and its annual proactive planning filings, hampering the discovery process that can inform the Commission's final decision. And, the JU Framework proposes that the Commission directly approve large project proposals—a category that is not even defined in the Framework[41]—potentially insulating those projects from subsequent prudency review to a level beyond that conferred through rate cases.

The uncoordinated overlap between National Grid and Con Edison's current rate cases and their respective Urgent Needs Filings illustrates these concerns. A significant share of the projects proposed in National Grid's Urgent Needs Filing were originally proposed within its rate case six months earlier.[42] Given the confidential nature of settlement negotiations within the rate case, parties commenting on National Grid's Urgent Needs Filing lacked insight into, or the ability to discuss publicly, the status of these negotiations and how they should inform the Commission's action in both proceedings. Con Edison, which initiated its current rate case two months after filing its Urgent Needs Filing, included all seven of its site-specific projects from its Urgent Needs Filing in its rate case testimony.[43] It chose to do so "because the timing for action on the Urgent Projects

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[39] JU Framework at 32.

[40] *See, e.g.*, Case No. 22-E-0317, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service*, Case No. 22-E-0319, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service*, Order Approving Joint Proposal (Oct. 12, 2023) (approving a Joint Proposal in a rate case filed in May 2022).

[41] JU Framework at 30-31.

[42] *See* National Grid Urgent Needs Filing at Appendix 1, Exhibit 1.

[43] Case No. 25-E-0072, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Electric Infrastructure and Operations Panel Prepared Testimony, at 40 (Jan. 31, 2025).

is not known at this time and, because this work must be done, the Company is pursuing funding in both venues."[44] Both utilities' actions to include overlapping project proposals in their rate cases and their Urgent Needs Filings were rational given the uncertain timeline, and the utilities' significant interest in securing cost recovery for the projects in question. But it also creates unnecessary complexity for the Commission, Staff, and stakeholders over how to address the overlapping nature of the proposals. This confusion would not go away under the JU's proactive planning process, as utilities would regularly find themselves in the midst of rate cases when making their interim filings.

EDF's proposal, described in further detail in Section III.D.4 below, would more appropriately fit within the existing rate case framework by allowing near-term use of a surcharge to recover incremental revenue requirement while retaining the rate case as the appropriate venue for prudency review of those investments.

3. Coordination with DSIPs

Finally, the Commission should modify the scope of the Distribution System Implementation Plan ("DSIP") process to align with EDF's proposed surcharge mechanism, discussed below. For a utility to recover the incremental revenue requirement of an investment through this surcharge, the utility should be required to show that the investment is consistent with the planning needs identified in its most recent DSIP. This would require modifications to the required elements of the utilities' DSIPs, which currently focus on ongoing and anticipated improvements to the utilities' internal processes, but do not discuss grid expansion and upgrade needs. This new element of the DSIP should not require the utilities to predict each specific asset or location in need of investments, as the reason for needing an interim cost recovery process is the inherent unpredictability of these needs at the asset level. However, the utilities should be expected to develop and detail a forward-looking plan as part of the DSIP that identifies expected energization needs for which the utility may need to utilize the surcharge. This includes specifying the factors driving system investment needs (e.g., transportation electrification), the types of assets requiring accelerated investment as a result (e.g., distribution transformers, broken down by voltage), factors delaying any such system improvement work (e.g., supply chain delays), and steps the utility is taking to address those delays (e.g., streamlining asset procurement). The utilities should also specify how their proactive planning efforts align with the utility process

[44] *Id.*

improvements already discussed within the DSIP filings, such as integrated system planning and advanced forecasting.

This recommendation is modeled in part on Massachusetts' utilities Energy Sector Modernization Plans (ESMPs)[45] and Oregon utilities' Distribution System Plans (DSPs).[46] Those Plans articulate, among other things, general factors driving utilities' distribution system needs, and utilities' forward-looking plans (including major projected projects over the next five years[47]) to address those needs. Regulatory "approval" (as in Massachusetts) or "acceptance" (as in Oregon) of the plan does not guarantee cost recovery for the projects therein;[48] rather, the plans help align expectations among stakeholders, and provide additional confidence that utility investments consistent with the plan are reasonable.

D. **Proactive Planning Process**

1. **Stage 1 – Load Assessment**

The JU filing starts with a Stage 1 - Load Assessment, which includes optionality for each utility and "is iterative and allows utilities to incorporate immediate and long-term customer needs, new data sources, and lessons learned while responding to evolving markets and policy environments."[49] These tenets are needed long-term, and EDF supports continual evolution of both the forecasts and this process as we learn more.

As discussed herein, EDF recommends utilities' load assessments incorporate:

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[45] *See* Background and procedural requirements on electric sector modernization plans, https://www.mass.gov/info-details/background-and-procedural-requirements-on-electric-sector-modernization-plans ("Each ESMP filed with the DPU must also include:

1. a summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments that have been reviewed, are under consideration or have been approved by the DPU previously;
2. identification of customer benefits for all proposed investments and alternative approaches to financing those investments;
3. three planning horizons for electric demand, including a 5-year and 10-year forecast and a demand assessment through 2050; and
4. a list of each GMAC recommendation, including an explanation of whether and why each recommendation was adopted, adopted as modified, or rejected.").

[46] Or. Pub. Utils. Comm'n, Docket No. UM2005, *Order Adopting Staff Report* at Appendix A, 14-15 (November 15, 2024) ("OR DSP Order").

[47] *See id.*; Mass. Dep't of Pub. Utils., Docket No .24-10, 24-11, and 24-12, *Order Approving Electric Sector Modernization Plans* at 16 (Aug. 29, 2024) ("MA ESMP Order").

[48] MA DPU has indicated intent to establish short-term interim cost recovery for ESMP costs, but it has not yet defined the specific mechanism(s) or applicable limitations. MA ESMP Order at 444-45. OPUC addresses recovery of DSP-related costs in utilities' base rate cases. OR DSP Order at Appendix A, p. 7. Section III.D.4 of these comments addresses cost recovery in further detail.

[49] JU Framework at 13.

1. Long-term forecasting horizon,
2. Forecasts rooted in location-specific methodologies,
3. Robust scenario analysis,
4. Policy compliance underpinning (at a minimum) the baseline planning scenario, and
5. Robust stakeholder engagement from the outset.

Such an approach will better equip planners to anticipate future challenges, promote equitable interim cost recovery, and ultimately foster a more cost-effective grid, while reducing risks.

Long-term Forecasting Horizon

With respect to the forecasting horizon, the JU filing does not mention a minimum forecast horizon to consider, stating only that "[p]lanning with an appropriately long time horizon avoids short-term piecemeal solutions and results in long-term cost savings for customers."[50] EDF recommends the Commission adopt a construct developed by the California PUC in its High DER proceeding,[51] which differentiates between the forecast horizon (how far in advance the utilities must forecast load) and the planning horizon (how far in advance the utilities must account for load forecasts in their system planning). The forecasting horizon should be consistent across the state, and consistent with policy objectives. Sufficiently long-term load forecasts (20+ years[52]) allow distribution planners to make informed decisions. The planning horizon may be shorter, depending on the risks and certainty of load forecasts, the lead-time required to implement the plan, and the cost effectiveness of proposed solutions. Different planning horizons may also be appropriate for different categories of grid assets; substations, for example, typically have longer construction timelines and therefore require a longer planning horizon to avoid contributing to customer interconnection delays, whereas new and upgraded circuit needs may be adequately met with shorter timelines.[53] To go along with the 20-year forecast horizon, EDF recommends a 10-year planning horizon as the default, and the Commission should direct the utilities to propose and

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[50] *Id*. at 22.
[51] Cal. Pub. Utils. Comm'n, Docket No. R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future*, Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and integration Capacity Analysis Maps, at 53-54 (Oct. 23, 2024) (adopting a 13-year forecast horizon to align with the statewide Integrated Energy Policy Report forecast horizon, and a 10-year planning horizon).
[52] *See, e.g., Bldg. for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 (FERC Order 1920) at P 248 (directing transmission providers to "use a transmission planning horizon of no less than 20 years into the future in developing Long-Term Scenarios").
[53] *See id.* (exempting line segments from the 10-year planning horizon due to their shorter construction timeline).

justify specific asset categories where a shorter planning horizon is warranted.

Regardless of the planning horizon, there are certain minimum characteristics that must inform forecasts that underpin utility investments. Principally, those forecasts must consider location-specific methodologies, such as consideration of traffic routes and building characteristics in forecasting future load. They must also capture temporal variation in load, such as EV charging patterns within a day, week, and year. These two components inform distribution planners about where and when load is realistically going to appear and allow them to design solutions that meet the forecasted customer need, rather than isolate on a generic distribution infrastructure capacity need.

Note that these minimum characteristics are not limited to the "top-down" versus "bottom-up" dichotomy that the JU Filing outlines, because either forecasting approach can be used in the development of high-quality load forecasts. The JU filing noted that: "[f]or instance, a 'bottom-up' approach could include using data at the distribution or customer level, whereas a 'top-down' approach could include using data at the State or zonal level."[54] EDF agrees, and encourages the use of bottom-up load forecasts; however, data granularity is not a substitute for data quality. An inferior customer-level forecast can be less informative than a good zonal forecast, potentially leading to a false sense of accuracy, false certainty, and ultimately inappropriate distribution investments.

Location-specific methodologies

The JU Framework appropriately recognizes the need for location-specific methodologies, stating that "[s]ome granular load study assumptions may differ by utility service territory due to local conditions, such as customer density (e.g., more dense and constrained service territory downstate), regional differences (e.g., urban versus rural), local policies, and customer or technology assumptions (e.g., differences in building stock)."[55] For many of these assumptions, however, the utilities should recognize their likelihood to vary on geographic scales smaller than the service territory, and design forecasts accordingly. For example, EV adoption is currently correlated with household income, and the differences in household income between communities

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[54] JU Framework at 14 n.29.
[55] *Id.* at 19.

within a utility's territory are likely greater than the differences between the utilities' territories.[56] Given the focus of the proactive planning efforts on identifying local distribution system upgrade needs, any forecasting methodology should account for these factors, rather than relying on simplified territory-wide assumptions where it is not reasonable to do so.

Robust Scenario Analysis

The JU Framework appropriately characterizes the need for multiple data sources depending on circumstances, but the filing does not go far enough to embrace robust scenario analysis informed by these data sources. The JU Framework notes that "[t]here is no 'one-size-fits-all' solution to identifying Proactive Planning needs, and utilities should leverage multiple forecast sources to best identify capacity constraints and future infrastructure needs."[57] The lack of a one-size-fits-all solution rings true, and Commission action should continue to allow utilities to develop forecasts suited for their service territory. But the wealth of data sources and assumptions points towards a greater need for multiple forecast scenarios, rather than inform a single utility forecast upon which planning decisions are made.

Recognizing the uncertainty in forecasting across data sources and assumptions, the utilities should employ at least three reasonable scenarios in planning, to help define different plausible ways that the grid might be impacted by anticipated electrification.[58] Scenario planning enables distribution planners and stakeholders to design and understand solutions that are robust across a range of potential futures, rather than settle on a design built from a single forecast that drowns out insights from different sources. To be effective, scenarios will need to be incorporated throughout the process: from load forecasting through solution identification, ideally on a circuit-by-circuit basis. Such scenario definition will help to reduce risk of inappropriate distribution investments by identifying solutions that are suitable across multiple future outcomes. At the same time, the utilities should strive for consistency and convergence around best methods, sources, and terminology, recognizing that they are all starting from different places with different

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[56] *See* Nadia Lopez & Erica Yee, *Who buys electric cars in California – and who doesn't?*, CalMatters (Mar. 22, 2023), https://calmatters.org/environment/2023/03/california-electric-cars-demographics/ (Finding that higher income ZIP codes have higher rates of EV adoption than lower income ZIP codes).
[57] JU Framework at 15.
[58] The need for three scenarios to capture EV charging uncertainty was identified by the Energy Systems Integration Group (ESIG) Task Force on Grid Planning for Vehicle Electrification whitepaper. The Task Force was made up of utility, regulatory, research, and industry stakeholders. https://www.esig.energy/grid-planning-for-vehicle-electrification/.

electrification drivers in their service territory.

The JU's emphasis on sources of data should also be expanded to include clear, defensible assumptions about future load. Indeed, utilities can craft robust forecasts derived from multiple data sources and any framework should allow for such optionality. However, there is a need to clarify the role of "data sources" and "assumptions" that stack on top of those data sources. Assumptions can include things like adoption rates, customer behavior, technological advancements (e.g. future battery charging speed), and charge strategies (depot vs. en-route, or DCFC vs. at-home). Together, these assumptions can influence the solution design more than the raw data source. As EDF explained in comments on the utilities' Urgent Needs Filings, it is not clear that the utilities are making reasonable assumptions regarding EV charging load profiles, managed charging, and contribution to coincident peak loads to adequately inform their system planning needs.[59] Unnecessarily conservative assumptions can result in overinvestment that threatens the cost-effectiveness of proactive planning efforts. The Commission should require the utilities to develop a consistent set of assumptions, or at minimum, a joint framework to discuss and align assumptions.

Such assumption coordination should have a well-defined scope beyond that articulated in JU Framework. The JU Framework states, "[t]he Joint Utilities will develop a list of common assumptions to support well-coordinated forecasts. This list will be presented at the Pre-Cycle Technical Conference."[60] It appears that the JU intend to only develop a list of common assumptions, rather than articulate all types of assumptions that can influence the load assessment. A framework for assumptions is needed, not just a list of common assumptions. Utilities may differ in their assumptions, but stakeholders and the Commission should understand how and why those assumptions differ and have an opportunity to inform and improve those assumptions.

Additionally, the Commission should require the utilities to show how they have considered load management and flexibility in their forecasting and planning. There is a major opportunity for the utilities to more comprehensively integrate load flexibility into their planning processes, including for building electrification, but principally as it relates to both managed EV charging programs and "naturally managed" charging behaviors among customers with EVs. Broadly, the U.S. Department of Energy Strategy for Achieving a Beneficial Vehicle Grid

[59] EDF Urgent Needs Comments at 23-24, 29-31, 37-39.
[60] JU Framework at 18.

Integration (VGI) Future notes that "**VGI implementation must start now**…..by acting now it is possible to purposefully plan investments, establish grid-friendly charging behavior through well-designed rates and programs, and provide EV drivers timely connections to charging for commercial and personal use."[61] In New York's proactive planning process, such implementation should be baked into the assumptions that underlie the planning process. Con Edison and National Grid provided limited data on participation in and impact of their managed charging programs in their January 2025 Managed Charging Program Implementation plans, and even this limited data shows that these programs are effective at shifting a significant portion of EV charging demand out of peak periods and into off-peak periods.[62] Moving forward, the utilities should be required to show how their assumptions regarding customer's charging behavior align with the best available information, and robustly justify any decision to exclude the impact of their own programs from their forecasting assumptions. The Commission should further direct utilities to file annual reports on EV load profiles, managed charging program outcomes, and other relevant data. Doing so would create a feedback loop that better informs future forecasts and investments.

The lack of perfect information on how and when customers will charge is not a valid reason to assume 100% on-peak charging for asset planning purposes. Instead, utilities should adopt conservative but evidence-based assumptions—coupled with stakeholder input and ongoing data collection—to reflect how charging behaviors might evolve and how customers respond to available utility programs. The JU filing notes that "[a]s they gain the needed experience, utilities **may** incorporate additional planning considerations, such as future flexible demand programs."[63] At a minimum, utilities should articulate a roadmap to what such "needed experience" entails and the metrics and data needed to incorporate load flexibility as a planning tool. Utilities should also consider flexible interconnection programs that incorporate load-limiting or load-control measures. Allowing customers (or aggregators) to opt into controlled load or demand response will reduce peak capacity requirements and can defer, mitigate, or entirely avoid costly infrastructure upgrades.

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[61] U.S. Department of Energy, Strategy for Achieving a Beneficial Vehicle Grid Integration (VGI) Future, at 2 (Jan. 2025) https://www.energy.gov/sites/default/files/2025-01/vgi-strategy_011725.pdf (emphasis in original). DOE defines VGI to include a broad set of approaches that include technical, market, and process considerations to integrate EVs and the grid.

[62] Docket 18-E-0138, *Consolidated Edison Company of New York, Inc. Managed Charging Implementation Plan* and *Niagara Mohawk Power Corporation d/b/a/ National Grid Residential Electric Vehicle (EV) Managed Charging Implementation Plan (MCIP)* (filed Jan. 30, 2025).

[63] JU Framework at 24 (emphasis added).

Policy Compliance

Current practices, such as the CGPP, rely on policy-compliant scenarios to set the standard. As discussed in Section III.A.1 above, EDF recommends that the Commission modify the JU Framework to clarify that the utilities should not only "consider" state policy compliance, but treat this compliance as the baseline assumption. Additional sensitivity analyses may be appropriate to study the differences in identified system needs where utility customers exceed the state goals, or fail to meet them. But the default assumption should enable compliance with state policy goals and applicable regulatory requirements.

Stakeholder Engagement

Recognizing that this is an area where best practices are continually evolving, utilities should work with stakeholders to define scenarios and assumptions early in the process. After-the-fact stakeholder input could require significant re-work and lead to inefficiencies in both cost and time, at a time when we must move quickly. The utilities' filing does not specify whether the Pre-Cycle Technical Conference will include an opportunity for feedback. To the extent feedback is provided, utilities should be required to show how that feedback was considered in their proactive planning efforts. Defining clear opportunities for active stakeholder engagement will be even more important if the Commission adopts EDF's recommended proactive planning cost recovery mechanism in place of the annual process proposed by the JU. In the absence of an annual stakeholder comment period on the utilities' project proposals, the Commission should clarify how stakeholders can provide feedback on the utilities' ongoing forecasting and planning efforts outside of individual rate cases.

2. Stage 2 – Planning and Solution Design

The Joint Utilities' (JU) filing outlines a reasonably thoughtful approach to planning and solution design, and each utility is generally best positioned to design and plan for its unique system needs. It would also be difficult to prescribe a single set of uniform practices within a single framework for system planning, given the differences in utility territories and grid conditions across the state. Nevertheless, there are opportunities to enhance the proposal in ways that enhance stakeholder engagement, streamline Commission review, and ensure that grid investments meet evolving policy and customer needs in a cost-effective manner.

EDF makes two recommendations regarding this section of the JU Framework. First, the utilities should adopt clear metrics and measurable indicators to guide and evaluate investment decisions. Second, utilities should more systematically consider alternative solutions—including modern capabilities in load flexibility, energy storage, and non-wires alternatives ("NWAs")—alongside traditional infrastructure investments. A robust evaluation of alternatives will help build a suitable "grid of the future" while mitigating risk and containing costs.[64]

Below, EDF addresses the JU filing's four subsections on Planning and Solution Design in turn.

B. 1 Coordination Across Utilities

EDF strongly supports efforts to coordinate across utilities, particularly with respect to forecasting inputs and planning best practices. Such coordination can reduce duplication and ensure more consistent modeling outcomes, all while accommodating territory-specific conditions and electrification drivers. By converging around a common framework—particularly for load forecasting assumptions, planning criteria, and terminology—utilities and stakeholders can better compare results, exchange lessons learned, and streamline processes.

B. 2 Best Practices for Planning in an Era of Load Growth

EDF strongly supports the considerations that the JU filing identifies as "best practices" in distribution system planning, including concepts that align with a "dig once" philosophy. That includes efforts that incorporate all forward-looking asset-related decisions, such as closely aligning asset management strategies with capacity expansion efforts. Based on responses to EDF's information requests, this appears to be standard practice in Con Edison's territory;[65] it would be helpful for the Commission, Staff, and stakeholders to understand whether, and if so how, this practice is currently employed in the remainder of the utilities' territories.

Each of these considerations should also be accompanied by clear metrics and definitions. For example, the filing defines "right-sizing" to mean "proactively preparing the electric system

[64] As discussed throughout these comments, proactive planning should not happen in isolation. EDF remains concerned that all discussions of load flexibility seem to be confined to the Grid of the Future proceeding (24-E-0165), despite the fact that such measures could have potentially large impacts on investment decisions and priorities in the context of long-term, proactive planning.

[65] EDF Urgent Needs Comments, at Appendix B p.44 ("The Company considers projected future loads when sizing replacements of the following distribution assets: 4kV Unit Substations, primary underground cable, primary overhead wires, and secondary overhead wires").

for load growth."[66] While EDF supports such actions, more detail is needed that would allow the Commission to discern whether the consideration is being appropriately followed. A standardized set of metrics or criteria could help the Commission and stakeholders discern whether, and how, each utility is sizing equipment in alignment with future demand, while avoiding inefficient overbuilding. Such metrics and criteria should apply to the decision-making process and not the ultimate utilization of such a project, which will unavoidably suffer from load forecasting error.

Importantly, the best practices identified in the JU filing should not be limited to "proactive" projects alone. Utilities should apply best practices across planning decisions so that the entire distribution grid benefits from forward-looking, analytically driven strategies.
More detail is needed on how each utility will implement these practices both in the "proactive" planning context and across all grid planning decisions. National Grid shared an example of this best practice in its Urgent Needs filing[67] and by sharing its updated distribution planning criteria in response to EDF Information Request 01-11.[68] These criteria and other documents, such as National Grid's Equipment Ratings Guide and Transformer Loading Guide, are ultimately what drive solution design within National Grid's territory.

Indeed, "proactive" planning is functionally indistinguishable from any other planning exercise premised upon forecast loads. The JU Framework notes that the best practice considerations apply to "long-term utility electrification planning" but does not explicitly identify where such planning occurs outside of this "proactive planning" proceeding. As such, Commission action should specify expectations with respect to implementation of these best practices across utility processes and proceedings.

To accomplish this goal of integrating forward-looking perspectives across all asset decisions, the Commission should instruct utilities to review all planning and rating/loading criteria and standards to ensure that the impacts from electrification are suitably captured and enable efficiency across all asset decisions. Utilities could then report on this as part of their DSIP, or present these findings through some other mechanism, such as a regular working group,

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[66] JU Framework at 23.
[67] National Grid Urgent Needs Filing at 27.
[68] EDF Urgent Needs Comments, at Appendix A p. 27-42. National Grid's new distribution planning criteria, among other things, "extends the planning horizon from 10 years to as far out as forecast data is available (currently out to 2050), lowering the threshold for developing distribution planning options to address thermal loading concerns from 95% to 80% of an asset's normal rating, and considering non-wires alternatives as possible hybrid and interim solutions rather than stand-alone alternatives only." *Id.* at 27.

outlining such practices. Utilities should incorporate stakeholder input as they update such criteria and planning standards in the future.

B. 3 Considering Alternatives in the Solution Development Process

Building upon forecasting and best practices, the solution development process ultimately involves selecting a solution from a variety of options. Notably, these options include (or should include) multiple traditional and alternative solutions. Utilities in New York are often adept at considering each of these through their processes today. For example, Con Edison's proposal and responses to EDF-015 and EDF-016 outline how the utility considered multiple traditional solutions for large infrastructure projects, from load transfers to new transformers.[69] Similarly, the JU filing notes that "existing utility planning and solution development processes include consideration of alternative solutions."[70] The New York utilities led the industry with the development of their NWA considerations, but simply continuing previous efforts will not be sufficient to cost-effectively meet future grid needs as technology continues to advance.

To further cement the consideration of alternatives, EDF recommends that the Commission require the utilities to provide a reasonably-detailed alternatives analysis as part of interim cost recovery proposals. Such analyses should describe the range of feasible solutions considered, including other traditional solutions, managed charging, demand response, energy storage, or other alternative strategies, along with the rationale for selecting or rejecting each option.

EDF appreciates that the JU intend to "consider alternatives to traditional grid infrastructure solutions that meet the utility's planning criteria—such as energy storage, other advanced technologies, and non-wire alternatives (NWAs) – to mitigate the risk of inadequate infrastructure."[71] However, "consideration" is not deployment. The slow pace of NWA implementation in New York to date suggests that additional steps may be appropriate to ensure a level playing field. Each utility should be required to (1) revise planning criteria relevant to NWAs, which should aim (in part) to mitigate planning biases that favor wires infrastructure; and (2) outline scenarios where alternatives to the proposed solution might be preferable. For example, the utilities' urgent needs filings saw little to no consideration of NWAs, with the utilities pointing to their NWA criteria that require the customer need to arise at least 18-36 months in the future,

[69] *Id.* at Appendix B p. 39-42.
[70] JU Framework at 24.
[71] *Id.*

despite most of the utilities' preferred wired solutions requiring as long or longer to enter service.[72] In the future, the utilities could detail how their alternatives consideration includes customer-specific solutions that do not require the long timeline of third-party solution procurement,[73] and the resulting change in their preferred solution processes. Reasonably robust alternatives analyses can be developed further through discovery into current utility criteria/standards, as mentioned above in the context of "best practices."

Put most simply, New York should encourage a middle ground between "NWA" as strictly defined today, which may include bridge to wires (BTW) as narrowly defined by Con Edison,[74] and traditional grid infrastructure that more evenly allocates risk between providers and utilities.

B. 4 Managing Risks and Realizing Benefits

The Commission requested input on "the magnitude of the risk… as well as approaches to manage this risk."[75] The JU's filing posits that there are asymmetric risks associated with building infrastructure early rather than late[76]—with which EDF agrees—but falls short of the Commission's instruction by failing to providing robust metrics and processes to quantify risks and benefits.

With respect to risk magnitude, the JU Framework describes risks in qualitative terms.[77] The Commission should require utilities to evaluate risks quantitatively – e.g., by comparing relative costs under different load scenarios – to identify optimal approaches. For example, the Lawrence Berkeley National Laboratory ("LBNL") recently released a report that articulated, among other things, considerations pertaining to "just-in-time" investments (e.g., project delays, revenue loss, stranded fossil assets, and missed policy targets) and from "investing proactively" (e.g., stranded asset risk, cost allocation concerns).[78] LBNL's report also outlined a risk management framework that could prove useful in this context, while remembering that the

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[72] *See, e.g.*, NYSEG/RG&E Urgent Needs Filing at 22-23; Case No. 16-M-0411, *In the matter of Distributed System Implementation Plans*, Utility Specific Implementation Matrices for Non-Wires Alternatives Suitability Criteria (Mar. 1, 2017).

[73] While outside the immediate scope of this proceeding, the Commission should consider how the third-party procurement process for NWAs may inhibit the use of flexible interconnection solutions where it is the customer triggering the grid upgrade need who would provide the solution to that constraint. As part of this, the Commission should consider whether changes to its definition of NWAs are warranted.

[74] EDF Urgent Needs Comments, at Appendix B p. 49-50.

[75] Proactive Planning Order at 9.

[76] JU Framework at 25.

[77] *Id.*

[78] Guillermo Pereira et al., Lawrence Berkeley National Lab, *Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments*, at 49-51 (Jan. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-03/unlocking_load_growth_berkeley_lab_final.pdf.

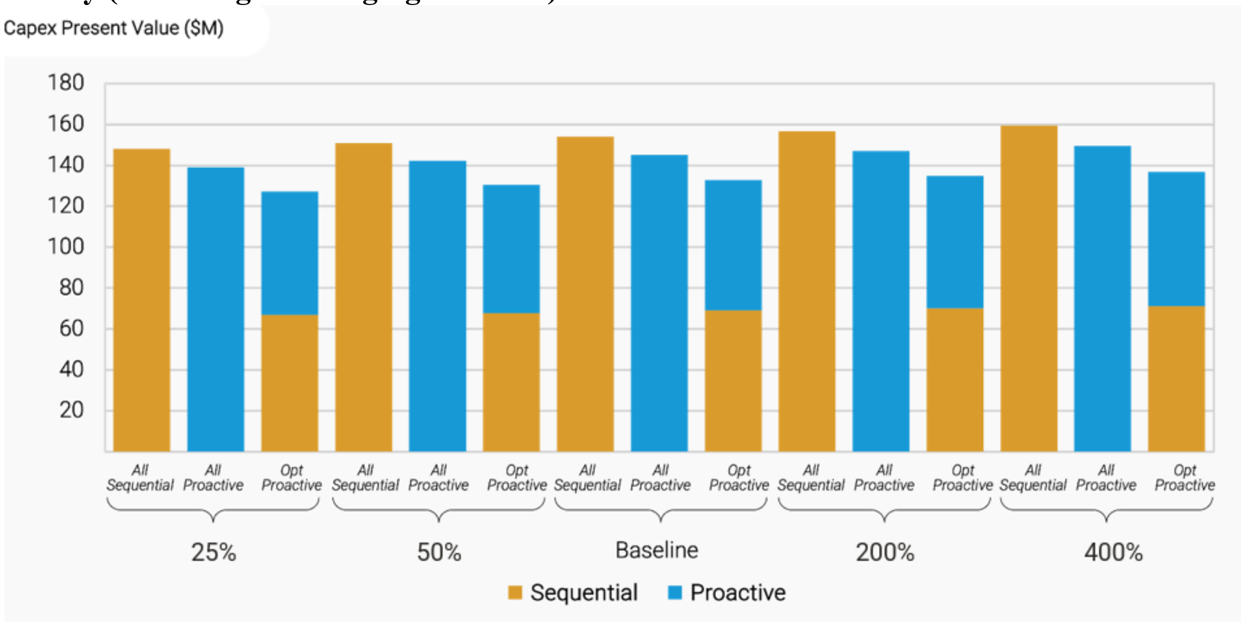
ultimate goal of this proceeding is to balance these risks, informed by forecast scenarios and stakeholder engagement.[79]

EDF commissioned a study from Black & Veatch, discussed in EDF's Urgent Need Comments,[80] which illustrates an approach to risk quantification.[81] The study analyzes the cost risk of building distribution facilities in anticipation of forecast electric vehicle loads. The study modeled the distribution systems of Con Edison and CenterPoint Houston Electric to compare the relative costs, on a present-value (PV) basis, of "sequential" (i.e., business-as-usual) asset deployments versus a "proactive" approach (defined in the study as anticipatory substation voltage upgrades). The model incorporated the utilities' system topology and cost data, and a baseline EV load forecast extrapolated from Electric Power Research Institute data.

The study found that the cost-optimal mix of solutions included both proactive and sequential asset deployments. Overall, an all-proactive approach tended to be cheaper than an all-sequential approach.[82] The study then tested the sensitivity of this finding to deviations in EV load forecasts. It modeled several different EV load scenarios, ranging from very slow (25% of baseline) to highly accelerated (400% of baseline), to assess the impact of those scenarios on the cost-optimal mix of solutions. Even under the slowest EV adoption scenario modeled, the proactive approach still yielded lower costs overall.[83]

[79] *Id.* at 72-78.
[80] EDF Urgent Needs Comments, at 11-12.
[81] EDF and Black and Veatch, *supra* note 23
[82] *Id.* at 7.
[83] *Id.* at 20.

Figure 1: Con Edison Forecasted PV Capital Expenditures by Planning Approach and Sensitivity (Unmanaged Charging Scenario)[84]



In other words, the study indicates that the cost risks of under- and over-building are probably not symmetrical. It may often be cheaper[85] to err on the side of building extra capacity into distribution assets, even in the face of forecast uncertainty. The advent of additional ahistorical sources of load – such as building electrification – can be expected to amplify this trend.

EDF raises this study for illustrative purposes. The above results will not hold uniformly for every utility in every instance. Rather, this study illustrates a type of analysis that can help manage the risks inherent in load forecasting, and which utilities should incorporate into system planning decisions moving forward.

With respect to risk mitigation, the JU "intend to use several approaches to manage risk," identifying eight bullet points.[86] The utilities should be required to show how they use each of the

[84] *Id.* at 25.

[85] Importantly, the study only considered utilities' distribution *costs*, it did not attempt to quantify the offsetting incremental *revenues* – or other benefits – that the investments would enable. For example, several other studies have demonstrated that EV loads tend to generate incremental utility revenues in excess of their incremental cost to serve. *See, e.g.*, Synapse Energy Economics, Inc., *Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification*, at 2 (Apr. 14, 2023), https://www.edf.org/media/worth-investment-report-finds-utilities-fleet-owners-consumers-benefit-when-utilities-cover; Synapse Energy Economics, Inc., *Electric Vehicles are Driving Rates Down for All Customers, January 2024 Update*, at 1 (Jan. 2024), https://www.synapse-energy.com/evs-are-driving-rates-down; Cal. Public Advocates Office, *Distribution Grid Electrification Model Study and Report*, at ES-2 (Aug. 2023), https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf.

[86] JU Framework at 26.

eight articulated approaches to manage risks, particularly including using sensitivities in the load forecast. Metrics and processes should also be designed to evaluate the success of these eight approaches over time.

The Commission should also encourage creative avenues for sharing or mitigating risk, such as tariffs that enable third parties to co-invest in proactive infrastructure or load flexibility solutions. By allowing a broader pool of participants to assume a portion of the risk, utilities can expand the scope and ambition of their proactive planning efforts without imposing undue burdens on ratepayers.

The JU filing also does not detail how utilities will measure or track the benefits of proactive investments. In addition to qualitative benefits like improved headroom for future load growth, utilities should project—and ultimately verify—quantitative impacts on emissions, overall system reliability, and customer bills.[87] These metrics can help stakeholders and regulators gauge whether a project's promised value is being delivered over time.

Planning and Solution Design Conclusion

In sum, the JU Framework outlines an approach that would improve upon current practices, and we commend the utilities' recognition that proactive distribution planning must evolve continually as technology, policy, and grid needs change. There remains significant room, however, to strengthen the JU proposal, including through:

- Early, collaborative stakeholder engagement that ensures assumptions and scenarios are well understood and agreed upon.
- A more structured framework for tracking metrics and evaluating alternative solutions.
- Consistent and transparent methods for incorporating load flexibility, demand response, and NWAs.
- Greater clarity around risk and benefit assessments.

Taken together, these enhancements will enable a more reliable, cost-effective, and future-ready grid—one that aligns with state policy goals and customer needs alike.

[87] *See also* Section III.E *infra*; EDF Urgent Needs Comments at 13-14.

3. Stage 3 – Project Eligibility and Prioritization Criteria

EDF generally agrees with the prioritization criteria specified in the JU Framework, subject to the recommendations made throughout these comments, with the exception of the criteria's consideration of DACs. The Proactive Planning Order requires that the criteria "incorporate and prioritize impacts to disadvantaged communities."[88] The JU Framework's criteria states that projects proposed through the framework must be consistent with state law including with respect to "impacts to Disadvantaged Communities."[89] For projects affecting these communities, "proposals will discuss how projects will impact and benefit those communities (e.g., through capacity created for beneficial electrification, localized reductions in emissions, and noise pollution abatement)."[90] While beneficial, this commitment does not go far enough to satisfy the Order's requirement that the utilities prioritize, rather than simply consider, DAC impacts. EDF's recommendations regarding this prioritization and community engagement more broadly are addressed in Section III.E below.

More broadly, the utilities' challenge will be in meaningfully implementing these criteria, and managing the interplay between them. For example, to "[d]emonstrate that an upgrade project is required to serve anticipated electrification load from transportation, buildings, industrial load, or economic development," utilities should be required to show how they considered load flexibility in assessment of needs and solutions. This will overlap with the "Degree of Certainty" of the project, as well as the "Availability of Alternatives."[91]

As explained in the subsequent section, EDF disagrees with the JU Framework's proposal to create an interim approval process for proactive planning processes, and proposes an alternative mechanism for interim cost recovery of certain utility electric capital investments. Because this mechanism would not apply solely to electrification-driven investment needs, it would not require electrification-specific eligibility criteria.

4. Stage 4 – Proposal and Project Authorization

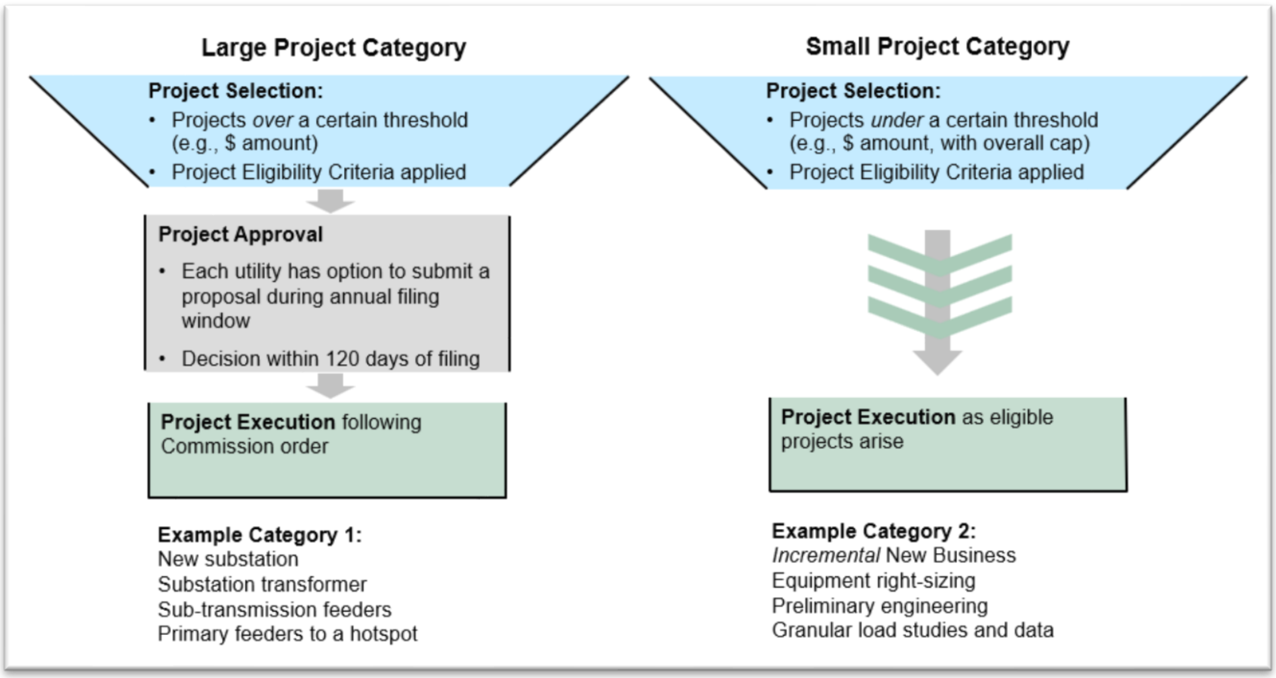
4.1 Flexible Approval Process

As the JU Framework notes, the Commission directed the JU to propose a "procedural approach for the Commission's consideration of transmission and distribution upgrade

[88] Proactive Planning Order at 11.
[89] JU Framework at 28.
[90] *Id.*
[91] *Id.* at 27-28.

investments, which shall evaluate options for requesting approval outside of rate case proceedings."[92] The JU Framework addresses this requirement by proposing a "two-category procedural approach" under which utilities could seek Commission authorization for Large and Small projects, which the Framework illustrates thus:

Figure 2. JU Framework Two-Category Project Authorization Process[93]



EDF has several concerns with this section of the Framework, most of which stem from its position that project reviews should occur in rate cases to the extent possible. The JU's proposal tactically omits explication of what Commission "approval" of a project under the Framework would constitute. This raises the possibility that "approved" projects might be immunized from review in rate cases. Such outcome is neither desirable nor necessary.

As EDF explained in Sections II and III.C.2 above and in its comments on the utilities' Urgent Needs projects,[94] rate cases provide several procedural advantages. Compared to rate cases, the JU's proposed process:

- <u>Does not provide commensurate opportunities for stakeholder participation</u>. The JU's proposed process would require a stakeholder technical conference during the load

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[92] *Id.* at 29; Proactive Planning Order at 9.
[93] JU Framework at 30.
[94] EDF Urgent Needs Comments at 4.

assessment stage of each annual cycle, but it does not propose how (or whether) stakeholders would weigh in on the utilities' proposed projects themselves.[95] Stakeholders' input would presumably be limited to the default comment window under the State Administrative Procedure Act, which provides for a single round of written comments within 60 days of a petition's publication in the State Register.[96]

- Does not provide clear opportunities for development of a robust factual record, such as through testimony, discovery, and cross-examination.
- Does not account for many factors that inform utility rate-setting, such as utilities' cost of capital, O&M expense management, taxes, and so on.

The JU's proposed process would also create perverse incentives. For example, it would incent utilities to delay proposing a project as part of a rate case until the need becomes "urgent," thereby qualifying the project for expedited review. It could also present opportunities for utilities to "game" the process by, for example, proposing the same projects in multiple simultaneous proceedings, with the aim of getting a decision in one proceeding that effects a *fait accompli* in the other.

EDF therefore urges the Commission to modify the Framework, and clarify its role thereunder, to preserve rate case primacy to the extent practicable. EDF discussed the Commission's appropriate role with respect to "project approval" in its comments on utilities' Urgent Need filings,[97] which we incorporate here by reference. In summary, we recommend that Commission "approval:" (1) places the project on equal footing with other capital projects (e.g., by affirming that the utility has made a *prima facie* showing that the project is necessary and is premised upon best practices) and is therefore presumptively prudent; and (2) authorizes the utility to recover appropriate net incremental revenue requirement until the utility's next base rate plan. Commission approval should not exempt the projects from rate case review entirely.

i. Commission Approval Should Not Exempt Projects from Review in Rate Cases

The first aspect of this recommendation, that Commission "approval" affirm a project's presumed prudency, fits within existing Commission precedent. Where a utility reasonably

[95] JU Framework at 34-35, Appendix 3.
[96] N.Y A.P.A. Law § 202.
[97] EDF Urgent Needs Comments at 3-7.

identifies the need for a capital project to comply with its statutory service obligations, the law already affords a strong presumption that it will be allowed to recover that project's costs.[98] This presumption extends to projects that have not previously undergone rate case review. As the Commission explained in its *Order Addressing Cost Recovery of Idlewild Project*, utilities routinely prioritize capital projects.[99] This includes "slip[ping] or substitut[ing] projects" identified in utilities' rate plans to make room for other projects—including projects that were not expressly identified in the utility's last rate case. "While such changes are subject to a prudence review, the Commission generally accepts the utility's reasonably supported decisions to slip or substitute projects."[100]

As EDF discussed in its comments on utilities' Urgent Need filings, utilities may be concerned that projects identified through newer forecasting methods, and/or that address ahistorical sources of load growth, might not enjoy this same presumption of prudency and are therefore somehow "riskier" than other projects.[101] The Commission can mitigate this concern as follows.

First, the Commission should disabuse any assumption that business-as-usual system planning is the lower-risk approach. As discussed above, and in the Commission's Order, plans that fail to account for emerging load sources can produce inefficient, mis-sized capital projects.[102] Planning that attempts to account for such loads – even where it does so imperfectly – will often produce more cost-effective outcomes overall.

Second, the Commission can direct utilities to include forecasted investment needs within their DSIPs, as recommended in Section III.C.3 above. This would provide all parties with previews of the types of projects needed to serve forecasted loads, as well as their associated costs and the underlying methodologies used to identify them. As Oregon PUC Staff explain, such a high-level review opportunity can help improve the predictability and quality of a utility's subsequent requests to recover project costs as part of rate cases:

> Staff proposed language to better highlight information in DSPs [Distribution System Plans] that will be useful in rate case analysis. This transparency was a

[98] *See Matter of Long Island Lighting Co. v. Pub. Serv. Comm'n of State of N.Y.*, 134 AD2d 135 (3d Dept 1987).
[99] Case No. 22-E-0064, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Order Addressing Cost Recovery of Idlewild Project, at 24 (Jan. 19, 2024).
[100] *Id.*
[101] EDF Urgent Needs Comments at 7.
[102] Proactive Planning Order at 5 ("[I]ncremental upgrades from individual load letters may result in inefficient expansion within a given service territory, where recently upgraded areas may require new capacity in short order.").

> fundamental driver of the PUC's decision to engage in DSP originally. Each utility commented that the proposed link between DSPs and future general rate cases amounts to pre-prudency review and argued that it was problematic. Energy Advocates expressed support for Staff's revisions that sought to better inform future rate cases. Staff fundamentally disagrees that requiring utilities to highlight the information, and report the level of granularity that will better support ratemaking analysis, amounts to pre-prudency review. Staff notes that DSPs are currently filed for Commission acceptance, so the emphasis remains on transparency and issue spotting, not approval. Further, the Commission does not consider, or act on, specific investments in the DSP. This level of review and Commission action are insufficient to constitute prudence determination. Staff also notes that prudence cannot be determined before a capital investment occurs, in other words, when a DSP is prepared and filed.
>
> Staff is not proposing to change the standard of review in cost recovery dockets or to use DSP information differently than the way parties have used IRP [Integrated Resource Plan] information in rate cases for decades. Staff is looking to make DSP a better venue for utilities to clearly articulate how they think through their spending decisions, and for Staff and parties to discuss the major risks, benefits, and potential alternatives of proposed spending strategies. Having this information better articulated in a DSP will improve the efficiency, quality, and predictability of the record for this significant and growing category of costs in rate cases. It will not replace consideration of whether a utility's spending decision was prudent based on the best information available at the time the decision was made. Nor will it alter the standards for setting rates to recover reasonable O&M costs based on the suite of relevant evidence at the time of the rate case.[103]

Third, the Commission can use its review of utility projects proposals to examine the forecasting and planning processes underpinning the project. Commission approval of interim cost recovery would constitute an affirmation that these processes are presumptively reasonable, notwithstanding novel aspects they might include. These clarifications should help reduce perceived barriers to investment while preserving precedent and maintaining an appropriate balance of risk between the utility and customers.

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[103] OR DSP Order, *supra* note 46, Appendix A at 7 (referring to Appendix A, Attachment 1 p. 10 ("The Near-term Action Plan should include a prioritized list of investments/expenditures, investment/expenditure summaries, and projected spending. These elements should guide DSP implementation and provide a preview of investments/expenditures for which cost recovery may be sought in future general rate cases. Where a utility's implementation of the Near-term Action Plan does not align with the Near-term Action Plan contained in the DSP, or does not align with more recent information included in the Interim Update, a utility should be prepared to explain its rationale for deviation in the cost recovery process."))

ii. The Commission Should Authorize Interim Cost Recovery Between Rate Cases, Subject to Limitations

This recommendation is intended to align utility incentives with EDF's and the Commission's shared objectives in this proceeding. EDF recognizes that emerging loads may necessitate system investments beyond the level contemplated in the utility's then-applicable rate plan. It will often not be cost-efficient—or even practicable—to substitute certain projects for others to keep under a capex ceiling. The law does not prevent utilities from investing (and recovering the costs of) more capital than their rate plan contemplates, but such "extra" investments can place strain on the utility's finances, including by (1) affecting the utility's access to capital; and (2) creating "revenue leakage" (i.e., depreciation expense, above the amount baked into the utility's rates, incurred between the asset's in-service date and the start of the utility's next rate plan). Such financial pressures can (but do not necessarily) ultimately detriment customers by driving up utility costs of capital.[104]

EDF therefore supports, with qualifications, the JU's proposal to allow utilities to recover certain net incremental project costs through a surcharge.[105] Such surcharge recoveries should incorporate reasonable limitations to protect customers. Namely, the surcharge should:

- <u>Incorporate incremental revenues, in addition to incremental costs, attributable to projects</u>. As EDF observed in its comments on utilities' Urgent Needs filings, "Incremental revenues attributable to a project should be deducted from that project's revenue requirement recovered through a surcharge or other mechanism; otherwise, the utility stands to over-recover."[106]

  The JU's proposal with respect to this issue—"Utilities will develop a methodology for assessing the incremental revenue requirement and revenues in consultation with DPS Staff"[107]—falls short in three ways. First, by failing to include

[104] EDF also notes the Massachusetts Department of Public Utilities' decision to allow "short-term targeted recovery of ESMP costs" through surcharges, based in part on its finding that "applying our existing standards for base distribution rates to ESMP costs would not provide sufficient revenues to support the step change needed to achieve the Commonwealth's GHG emissions targets in the current operating environment." MA ESMP Order, *supra* note 4747, at 442-43. The DPU's finding is of limited relevance in New York, which differs from Massachusetts in several ways including (but not limited to) "standards for base distribution rates," "GHG emissions targets," and utility "operating environment." However, EDF acknowledges parallels between MA's ESMPs and the instant proceeding.

[105] JU Framework at 33.

[106] EDF Urgent Needs Comments at 16.

[107] JU Framework at 34.

such a methodology, the JU's proposal does not satisfy the Order's direction that it "incorporate an analysis of the estimated revenue requirement and offsetting incremental revenues associated with the infrastructure development . . . ."[108] Second, utilities currently appear to calculate incremental project revenues in different ways;[109] resolving these differences through a transparent review would promote clarity and uniformity. Third, the JU's proposal discusses *assessing* incremental revenues, but skirts the issue of how (if at all) such revenues would offset surcharge recoveries.

The Commission should address each of these shortcomings in this proceeding. It should direct the JU to supplement its proposal with a recommended methodology for calculating the surcharge. This methodology should expressly incorporate forecasted incremental revenues as an offset to project costs, and include a mechanism to reconcile forecasted and actual incremental revenues. EDF would not object to the JU developing such a proposal in collaboration with DPS Staff.

- <u>Only recover net incremental revenue requirements above the revenue requirement contemplated by the utility's then-applicable rate plan.</u> This would safeguard against double-recovery of costs.

- <u>Apply only to investments consistent with the utility's DSIP.</u> As discussed in Section III.C.3 above, EDF recommends utilities' DSIPs include a summary of the types, and rough costs, of capital investments it anticipates making over the term of the DSIP. A utility's request to include an investment's incremental revenue requirement in its surcharge should demonstrate that the investment is consistent with the DSIP. This limitation would provide all parties with greater predictability in the costs to be recovered through the surcharge. This recommendation is also consistent with cost

[108] Proactive Planning Order at 9.
[109] EDF asked each Con Edison, National Grid, and NYSEG/RG&E to provide estimated incremental electric sales and distribution revenues attributable to their respective Urgent Needs projects. Con Edison provided estimated incremental delivery revenues attributable to certain projects, broken down by year, through 2050. EDF Urgent Needs Comments, at Appendix B p. 2-7. National Grid provided estimated delivery revenues for certain projects through 2045, but these estimates included only revenues from "EV Charging Load," omitting other incremental loads that the projects would also serve. *Id*. at Appendix A p. 2-5. NYSEG/RGE indicated that they had "not assessed any incremental (i) electric sales and (ii) distribution revenues attributable to each of the projects included in the Urgent Needs Projects Proposals." *Id.* at Appendix C p. 2.

recovery mechanisms employed in Massachusetts,[110] Pennsylvania,[111] and New Jersey,[112] discussed in elsewhere in these comments, each of which condition interim cost recovery on consistency with a public plan.

- Be capped. Absent a surcharge cap, a utility could theoretically decline to file rate cases, and instead recover incremental capital costs through the surcharge, indefinitely. A cap safeguards against this scenario, and incentivizes utilities to file rate cases (and roll the surcharge into base rates, resetting it to zero) where they anticipate significant incremental capital investments.[113] EDF suggests establishing an initial cap at 2% of the utility's annual delivery revenues.

- Sunset in 2030. As discussed above, utilities (and the Commission) should strive to anticipate and prepare for emerging loads as a matter of normal course, such that the corresponding system investments become "baked into" utilities' base rate plans.[114] Effective utility planning should ultimately obviate the need for inter-rate-case capital cost recovery. To that end, the Commission should establish the expectation that the surcharge mechanism will not last forever. EDF suggests the Commission allow utilities to use the surcharge for a five-year transitional period—i.e., through 2030—after which it would terminate automatically, unless the utility receives Commission approval to continue the surcharge upon a showing of good cause.

This structure is modeled on approaches used in other states, including:

- Pennsylvania utilities' Long-Term Infrastructure Improvement Plans ("LTIIPs") and corresponding Distribution System Improvement Charge ("DSICs"),[115] which enable utilities to recover incremental revenue requirement of certain capital investments placed in-service between rate cases. To be eligible for recovery through the DSIC, an

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[110] MA ESMP Order, *supra* note 4747, at 444.
[111] 66 Pa. Cons. Stat. § 1353 *et seq*.
[112] N.J. Admin. Code § 14:3-2A.1 *et seq.*
[113] As discussed later in this Section, Pennsylvania's Distribution System Improvement Charge (DSIC) employs such a cap mechanism. *See* 66 Pa. Cons. Stat. § 1358(a)-(b).
[114] *See also* MA ESMP Order, *supra* note 4747, at 443 ("The Department has long held that grid modernization investments should become the Companies' normal business practice over time and, as a result, cost recovery for grid modernization should transition from short-term, targeted cost recovery to base distribution rates to restore the benefits of regulatory lag to ratepayers.").
[115] 66 Pa. Cons. Stat. § 1353 *et seq.*

investment must, among other things, (1) be related to the utility's Commission-approved LTIIP; (2) fall into one of the categories of "eligible property" defined in statute;[116] and (3) not have previously been reflected in the utility's rates.[117] The DSIC is capped by default at 5% of the utility's annual distribution revenues.[118] A utility's DSIC rates are rolled into base rates, and the DSIC is reset to zero, at the start of each new rate plan.[119]

EDF's proposal differs from the DSIC most significantly in the type of plant eligible for surcharge recovery. The DSIC may only be used to recover "costs incurred to repair, improve or replace eligible property"[120] —i.e., asset-management-type projects—and not for costs associated with system expansion projects. EDF does not recommend the Commission impose a similar limitation here, because it would exclude revenue-producing, system-expansion projects needed to accommodate load growth.

- New Jersey utilities' Infrastructure Improvement Programs ("IIPs") and corresponding surcharges,[121] which function similarly to Pennsylvania's LTIIPs/DSICs. Utilities with approved IIPs may recover incremental revenue requirements of "non-revenue producing" plant[122]—i.e., asset-management-type projects—through a surcharge between rate cases. In lieu of a surcharge cap based on a percentage of utility revenues, surcharge recoveries are controlled through a utility earnings test,[123] and utilities are required to file a rate case within five years of IIP approval.[124] Additionally, by statute, "Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be provisional, subject to refund and interest. Prudence of Infrastructure Investment Program expenditures shall be determined in the utility's next base rate case."[125]

[116] *Id.* § 1351.
[117] *Id.* § 1357(a).
[118] *Id.* § 1358.
[119] *Id.*
[120] *Id.* § 1353.
[121] N.J. Admin. Code § 14:3-2A.1 *et seq.*
[122] *Id.* § 14:3-2A.2(a). Again, EDF does not recommend the Commission employ a similar limitation here.
[123] *Id.* § 14:3-2A.6(h)-(i).
[124] *Id.* § 14:3-2A.6(f).
[125] *Id.* § 14:3-2A.6(e).

iii. ***The Commission Should Make Further Modifications to the Framework Consistent with Above Recommendations***

The Commission should reject the JU Framework's proposed "Large" and "Small" project categories and corresponding separate budgeting process for "Small" projects. This structure is unnecessary, lacks definition, and falls short on procedural protections.

EDF's recommended clarifications with respect to cost recovery obviate the need for firm project categories. In the JU Framework, such categorization functions mainly to identify which capital investments may be eligible for a pre-approved budget. EDF's recommended approach to cost recovery does not include such budgets, because it would not "pre-approve" incremental spending between rate cases; such investments would be eligible for interim cost recovery only until the next rate case. EDF recognizes the expediency of grouping together smaller similar projects (e.g., pole replacements, circuit voltage upgrades, etc.) for review purposes. EDF recommends allowing utilities to "bucketize" such projects in their requests for interim cost recovery thereof. In the absence of pre-approved programmatic budgets, it is not necessary to strictly define here which types of projects may be eligible for such "bucketization." EDF instead recommends encouraging utilities to explain programmatic project categories in rate cases and DSIPs, and where possible, to use those same categories in their interim cost recovery requests.

In the alternative, even if the Commission does not accept EDF's recommendations with respect to cost recovery, it should still reject the JU Framework's "Small" project category, because the category is not adequately defined. Specifically, the JU Framework does not articulate any meaningful limitation on the types of projects that may qualify as "Small." The JU instead proposes to defer this distinction to a future filing.[126] If the distinction between "Large" and "Small" is to carry import (which, as discussed above, EDF recommends against), then it should be defined at this stage of the proceeding, to align stakeholder expectations.

4.2 Cost Allocation

Consistent with its comments on utilities' Urgent Needs proposals,[127] EDF agrees with JU's proposal to "maintain[] cost allocation principles consistent with mechanisms under each utility's respective Commission[-approved] rate case cost recovery requirements and/or tariffs."[128]

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[126] JU Framework at 31.
[127] EDF Urgent Needs Comments at 17.
[128] JU Framework at 32.

EDF does not recommend substantially altering cost allocations outside of rate cases.

4.3 Cost Recovery

As discussed in Section III.D.4.1 above, EDF supports the establishment of a surcharge mechanism to recover incremental utility revenue requirement on an interim basis, subject to appropriate clarifications and limitations. EDF incorporates those recommendations by reference here.

Additionally, consistent with EDF's recommendations on utilities' Urgent Needs filings,[129] the Commission should revise the Framework's discussion of Construction Work in Progress ("CWIP") to accommodate more flexibility. The Framework implies that a utility may be granted either 100% CWIP recovery, or 0% CWIP recovery, with respect to projects proposed through the Framework.[130] To the extent the Commission opts to allow CWIP treatment, it should retain the discretion to authorize an intermediate amount of CWIP recovery (e.g., 50%), where appropriate to share risk between the utility and customers.

4.4 Additional Revenue Requirement and Incremental Revenues

EDF incorporates its recommendations at Section III.D.4.1 by reference here.

E. **Stakeholder and Community Engagement**

The JU Framework's discussion of Community Engagement lacks sufficient detail and actionable commitments. The JU "propose a stakeholder engagement process that incorporates lessons learned and best practices from past experiences and applies them to the needs of the Proactive Planning Proceeding." EDF appreciates utilities' commitment to incorporate lessons learned, a superior approach would be commit to sourcing and implementing community engagement best practices from other relevant distribution planning proceedings and other sources. Limiting the commitment to learning solely from their own past experiences would ignore best practices developed elsewhere.

There are other distribution proceedings in Oregon[131] and Massachusetts[132] (the latter of which includes areas served by a National Grid affiliate) that should inform the JUs' community

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[129] EDF Urgent Needs Comments at 16-17.

[130] JU Framework at 33 ("The Joint Utilities also propose to have the option to either (1) include 100 percent of Construction Work in Progress (CWIP) in rate base on a current basis (i.e., as capital is spent), or (2) accrue Allowance for Funds Used During Construction (AFUDC).").

[131] *See* OR DSP Order, *supra* note 4646.

[132] *See* MA ESMP Order, *supra* note 4747.

engagement planning.

Practices worth emulating in National Grid's Electric Sector Modernization Plan include the creation of a state-wide community engagement framework to provide guidance on how utilities should work with "potentially impacted communities"[133] and stakeholders prior to the deployment of clean energy infrastructure projects, and the establishment of a Community Engagement Stakeholder Advisory Group (CESAG)[134]—consisting of utility representatives, representatives from community based organizations, and an environmental or equity advocate - to facilitate the development of the aforementioned framework.

Oregon's DSP framework, discussed above, also provides community engagement requirements that could be adapted for a New York Context. Similar to National Grid's ESMP plan, the Oregon utilities' DSPs include community engagement plans that "describe actions the utility will implement in order to engage community members and CBOs [Community Based Organizations] . . . if it needs to engage communities around implementing larger projects that may have a reasonable expectation of impacting surrounding communities."[135] Utilities must also "document community and stakeholder comments and feedback that were heard but not implemented."[136]

The Framework's discussion of community engagement, in contrast, contains significantly less detail than these above examples or other portions of the Framework. It mentions only two actionable items: convening an Annual Stakeholder Technical Conference and engaging with local representatives through a variety of channels.[137] And importantly, despite mentioning both action items, the utilities only commit to the former. The lack of a more substantive proposal is confusing, given that the JU Framework alludes to the best practices from Con Edison and National Grid, but does not then specify what those best practices are or how to make them consistently actionable.[138] EDF recommends, consistent with its recommendations for the utilities' Urgent Needs Filings,[139] that the Commission direct the JU to align and coordinate their respective community engagement and outreach processes and best practices and make them publicly available.

In developing and promulgating community engagement plans, utilities should prioritize

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[133] *Id*. at 57.
[134] *Id.* at 56.
[135] OR DSP Order, Appendix A at Attachment 1, p.4.
[136] *Id*.
[137] *Id.* at 34-35.
[138] *Id.* at 34.
[139] EDF Urgent Needs Comments at 15.

procedural justice and utility accountability. EDF has previously raised the importance of these two concepts before the Commission, including in its comments on the utilities' Urgent Needs Filings, and in its comments in response to Commission questions on climate justice and the CGPP.[140] Procedural justice, which "relates to the accessible and meaningful participation of individuals in the energy decision-making processes"[141] will play an outsized role in the outcome of community engagement and outreach. How the JUs conduct community engagement and outreach is critical in the success of their efforts. To ensure that community engagement and outreach is conducted earnestly with best available practices, it is critical to set clear expectations for the JUs and track their performance against set standards.

Centering procedural justice is necessary to ensure that stakeholder and/or community engagement is robust and meaningful. Within the context of the Proactive Planning Framework, robust stakeholder engagement should entail hosting multiple stakeholder meetings in multiple formats to engage with the communities heavily affected by or hosting major capital projects. EDF recommends a mix of virtual and in-person meetings. To support informed stakeholder involvement engagement in proceedings, the JUs could offer educational conferences for stakeholders to learn more about grid planning at large. EDF recommended that the Commission direct similar meetings in our comments on the CGPP and climate justice.[142]

The Commission should also consider creating an intervenor compensation fund that could contribute to robust engagement by allowing smaller organizations and/or community-based organizations to mitigate a person's earnings lost by participating in utility engagement and outreach. Intervenor funding may also help alleviate concerns that those organizations have about dedicating people-hours to a proceeding where the potential benefits may be unclear. Intervenor funding has been recommended as a method to increase community engagement in a variety of public forums. In their Energy Equity Report, the Energy Equity Project identifies intervenor funding as a technique to encourage community engagement.[143] Similarly, the City of New York

[140] Case No. 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Responses of the Environmental Defense Fund to Questions on Stakeholder Engagement (Feb. 7, 2025).
[141] NARUC, *Energy Justice Background Brief For State Roundtable Co-Hosted by NARUC, NASEO, and NGA*, https://pubs.naruc.org/pub/A1C0B23B-1866-DAAC-99FB-114B0C92BAAA.(Apr. 22, 2022).
[142] Case No. 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Responses of the Environmental Defense Fund to Questions on Stakeholder Engagement (Feb. 7, 2025).
[143] Energy Equity Project, 2022. "Energy Equity Framework: Combining data and qualitative approaches to ensure equity in the energy transition." *University of Michigan – School for Environment and Sustainability (SEAS).*

highlighted that intervenor funding or an honorarium could encourage community engagement in transmission planning.[144] In both cases, the parties highlight intervenor funding as a viable method to increase stakeholder engagement.

Meaningful community engagement would help ensure that communities and other stakeholders are able to directly shape the outcome of projects. Practices that would facilitate this outcome are early engagement of community members and community identification of priority outcomes. The JUs should begin engagement and outreach to communities as soon as possible. This approach ensures that communities are in a position to influence a project. If communities are only brought into the planning process when the plan is already largely complete, then their potential to shape the project is significantly diminished. The utilities should also clearly set expectations on the scope of items that community members can reasonably expect to influence. Even if that scope includes a broad range of possibilities, it will be a helpful tool so organizations, particularly small and community-based ones, can determine to what degree the possible outcomes justify their involvement.

Community engagement that supports procedural justice can also serve as a way of fulfilling the Order's directive that the Framework prioritize impacts to DACs.[145] As explained in EDF's comments on the Urgent Needs Filings, "Meaningful involvement would allow DACs to prioritize certain community impacts, express concerns earlier in the planning process, and build a rapport with their utility."[146] Rather than simply including a qualitative discussion of how a project would impact a DAC, as the JU propose,[147] a clear explanation from the JU regarding how they will engage with the communities and incorporate their feedback in project design and implementation is necessary for this to be any more than a box-checking exercise.

Finally, the Commission should adopt clear metrics and reporting requirements to understand how DACs and other communities are impacted by the proposed projects, and how the utilities are engaging with those communities. While procedural justice will lay the initial groundwork for comprehensive community engagement, utility accountability in the engagement process is critical to sustaining community engagement. Consistent with EDF's comments on

[144] Case No. 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Responses of the City of New York to Questions on Stakeholder Engagement (Dec. 13, 2024).
[145] *See supra* Section III.D.3.
[146] EDF Comments on Urgent Needs Filings at 15.
[147] JU Framework at 28.

utilities' Urgent Need proposals,[148] utilities should track:

- Reliability impacts[149] (e.g., CAIDI, SAIDI, SAIFI, etc.), measured separately for DACs and non-DACs

- Affordability, as roughly approximated by comparing a project's incremental revenues to incremental costs

- Access to distribution grid capacity (e.g., system headroom, EV deployments enabled), measured separately for DACs and non-DACs

- Land Use impacts[150] (e.g., acres used for energy infrastructure), broken down by:
    - DACs vs non-DACs
    - Residential vs non-residential areas
    - Greenfield vs brownfield sites

- Community engagement[151]
    - Number of outreach and involvement meetings hosted by members of the JU on the Proactive Planning Framework to engage with stakeholders including but not limited to DACs, community organizations, municipal leadership, and customers
    - Number of outreach and involvement meetings hosted by the JU to engage with stakeholders including but not limited to DACs, community organizations, municipal leadership, and customers per filed Urgent Need Project

Consistent with the discussion in Section III.D.4 above, EDF does not recommend the creation of an approval process for proactive planning projects separate from the existing utility capital planning and cost recovery process, but supports interim cost recovery for projects meeting certain requirements. Under EDF's recommendation, therefore, these tracking requirements would apply to any projects for which a utility pursues interim cost recovery. But regardless of the specific structure approved by the Commission, incorporating these metrics is a critical component of a robust proactive planning framework that meaningfully incorporates community input.

IV. **Other Comments**

The following recommendations do not correspond to specific enumerated sections of the JU Framework.

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[148] EDF Comments on Urgent Needs Filings at 13-14.

[149] *See* Case No. 22-E-0064, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, 2023 Annual DAC Report (May 31, 2024) (including examples of reliability statistics disaggregated by certain geographic areas).

[150] *See* National Grid, *Future Grid Plan* at 375 (Jan. 2024), https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan.pdf (discussing approach to "Avoided Land Use Impacts" with respect to distribution system investments).

[151] See *id*. at 38-58.

A. **Recordkeeping and Reporting**

The JU Framework proposes limited reporting requirements associated with "Small" projects,[152] but lacks corresponding discussion for "Large" projects. The Commission should direct utilities to file periodic reports to track projects approved for interim cost recovery regardless of project size. Such reporting will help the Commission and utilities monitor project impacts and costs, refine forecasting assumptions, and support ongoing methodology improvement. The reports should include the community impact metrics identified in Section 3.E, as well as other data such as:

- Project cost, including a comparison of actual and forecast costs
- Project status
- For completed projects:
    - The total energy and peak demand served by the project, including a comparison to forecasts
    - Incremental revenues enabled by the project, including a comparison to forecasts
    - Asset utilization factors (average load / rating)

These data could be reported as part of utilities' base rate case filings, unless the Commission determines that more frequent reporting should be required.

V. **Conclusion**

The Commission's Initiating Order directed a "statewide, collaborative framework for proactive planning to support the needs of New Yorkers as we focus on electrification of the transportation and building sectors to further our climate change goals."[153] The JU's proposed Framework brings this vision to fruition in several respects but falls short in others. EDF's proposed modifications will ensure that the Commission's objectives are fully realized. To that end, EDF respectfully requests that the Commission adopt its recommendations when ruling on the JU's proposed Framework, which will help meet emerging electrification needs, support New York's electrification targets, maximize the value of grid investments, and incorporate important guardrails to protect customers.

[152] JU Framework at 31-32.
[153] Proactive Planning Order at 4.