KEEGAN WERLIN LLP

ATTORNEYS AT LAW

99 HIGH STREET, Suite 2900

BOSTON, MASSACHUSETTS 02110

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(617) 951-1400

TELECOPIER:

(617) 951- 1354

February 5, 2021

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: DG Interconnection – D.P.U. 20-75

Dear Secretary Marini:

On behalf of NSTAR Electric Company d/b/a Eversource Energy ("Eversource"), enclosed are Eversource's Reply Comments regarding the Straw Proposal offered by the Department of Public Utilities addressing distributed generation interconnection cost allocation methodologies and system planning.

Thank you for your attention to this matter. Please contact me if you have any questions regarding this filing.

Sincerely,

John K. Habib

John K. Habib

Enclosures

cc: Katie Zilgme, Hearing Officer
D.P.U. 19-55 Service List

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Inquiry by the Department of Public Utilities On its own Motion into Distributed Generation Interconnection System Planning and Cost Allocation	)))))	D.P.U. 20-75

REPLY COMMENTS OF
NSTAR ELECTRIC COMPANY d/b/a EVERSOURCE ENERGY

I. INTRODUCTION

On October 22, 2020, the Department of Public Utilities ("Department") issued a Vote and Order opening an investigation into (1) Distributed Energy Resource ("DER") Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation. The Department issued a straw proposal on these topics for stakeholder review and comment.

On December 23, 2020, in addition to the NSTAR Electric Company d/b/a Eversource Energy (the "Company"), the following stakeholders submitted comments for Department consideration: the Office of the Attorney General ("AGO"); Department of Energy Resources ("DOER"); Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"); Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") (the Company, National Grid and Unitil collectively referred to as the "EDCs" or "Distribution Companies"); Northeast Clean Energy Council ("NECEC"); Solar Energy Business Association of New England ("SEBANE"); Interstate Renewable Energy Council, Inc. ("IREC"); Pope Energy ("Pope"); Zero-Point Development, Inc. ("Zero Point"); JCD Solar Consulting, LLC, d//b/a

Melink Solar Development ("Melink"); BlueHub Energy ("BlueHub"); and Low-Income Weatherization and Fuel Assistance Program Network ("LEAN").

The Company appreciates the opportunity to reply to several of the key stakeholder recommendations, below. As noted in D.P.U. 19-55, Eversource recommends that the Department and stakeholders consider Massachusetts DER-related infrastructure modifications and the allocation of costs associated with those upgrades within a broader context of the Commonwealth's clean energy and climate policies that directly impact the electric power system.

Recently, the Commonwealth issued its 2050 Decarbonization Roadmap Study ("Roadmap") to provide an understanding of strategies and transitions to achieve "Net Zero"[1] by 2050 through decarbonization (Roadmap at 7). According to the Roadmap, the electric system is responsible for 19% of statewide emissions. The report states that solar is one of the best options to reduce emissions and will compromise the bulk of the electricity generated in 2050. The Roadmap found 20-23 GW of solar capacity will be needed to achieve the state's decarbonization goals (Roadmap at 58). The Commonwealth also issued an interim Clean Energy and Climate Plan for 2030 ("2030 CECP"), that sets the statewide GHG emissions limit to 45% below the 1990 GHG emissions level for the year 2030 (CECP at 1). With regard to solar, the 2030 CECP recommends continuing to deploy solar and facilitating an additional 2 gigawatts of new distributed generation between 2030 and 2050 (id. at 41). To these ends, the DOER promulgated updated SMART regulations in 2020 to incentivize an additional 1,600 megawatts of solar distributed generation in the Commonwealth, among other programs promoting the development of solar.

[1] "Net Zero" is defined as "A level of statewide greenhouse gas emissions that is equal in quantity to the amount of carbon dioxide or its equivalent that is removed from the atmosphere and stored annually by, or attributable to, the Commonwealth; provided, however, that in no event shall the level of emissions be greater than a level that is 85 percent below the 1990 level."

Clearly, the long-term design of the electric power system in Massachusetts will be directly influenced by a range of critical clean energy and policy goals. The integration of renewable DER resources is an important goal that will continue to impact the electric power system. As always, Eversource works to plan distribution and transmission investment in an optimal manner, consistent with all applicable state policy goals. Eversource expects that, by doing so, its system will be more efficient, lower cost and of greater value to assisting in state policy goals over the long term.

Optimal system planning will necessarily incorporate the near-term infrastructure requirements for the interconnection of DER and it will remain appropriate for DER facilities creating the most immediate needs for infrastructure modifications to contribute to the costs of those modifications and receive price signals to inform development decisions appropriately. However, optimal infrastructure modifications will inevitably address system needs that extend beyond the interconnection of the immediate queue of DER facilities. Therefore, in such cases it is not necessarily appropriate to allocate the full cost of infrastructure modifications to current DER facilities. Eversource recognizes that the continued evolution of the electric power system may increasingly involve major infrastructure modifications that will both enable the near-term interconnection of DER resources and also have the potential to serve the longer-term needs of the electric power system.

By way of example, Eversource is currently processing applications for solar distributed generation in its service territory totaling about **1,730** MW (ranging from less than 200 kW to over 5 MW). These proposals come at a time where the Company's distribution infrastructure is saturated with DER that has been interconnected primarily over the last 10 years, incentivized in large part through the Commonwealth's previous solar incentive programs, including its Solar

Renewable Energy Certificate-I and II programs, and the original SMART program. This high demand to interconnect solar necessitates details and sophisticated studies to determine designs that will allow the safe and reliable interconnection of these facilities to the Company's distribution system and, relatedly, the interstate transmission system. Eversource is currently performing distribution group studies to review the potential safety and reliability impacts of interconnecting 146 projects totaling about **340** MW. At the same time, Eversource's transmission staff is working in close coordination with ISO-NE to complete Affected System Operator studies to review the potential safety and reliability impacts to the interstate transmission system of interconnecting 80 projects totaling over **300** MW. Although these studies have not yet been completed, Eversource anticipates the estimated costs to interconnect these facilities may total **over $675** million[2]. Moreover, the time necessary to complete these studies is significant.

These challenges require the Department to address current barriers to the continued growth of DER in Massachusetts through changes that are consistent with long-term objectives for cost allocation and design of the electric power system. In order to successfully meet these challenges, Eversource's proposal is that the Department authorize the EDCs to: (1) identify optimal infrastructure solutions that address future system needs in addition to requirements for the near-term interconnection of DER facilities through concurrent interconnection and system planning studies; and (2) appropriately allocate the costs of DER-related infrastructure modification to an expanded group of DER facilities, which includes future projects that may be enabled by the current infrastructure modifications made to accommodate DER interconnections today. The allocation of infrastructure modification costs to future, as-yet unknown DER facilities will reduce the cost responsibility of current DER facilities on an equitable basis in many cases

[2] This is a high-level order of magnitude estimate that does not include the high-side (transmission) portion of substation upgrade costs that may also be needed. Refined cost estimates are currently being developed for each group.

and will mitigate the potential for free-ridership in the future by providing for contributions by future DER facilities.

II. NEED FOR REVISED COST ALLOCATION POLICY

As the Department established in its Vote and Order Opening Investigation in this proceeding, in setting rates for utility service and otherwise providing for the recovery of costs by utilities, the Department applies the basic principle of cost causation; that is, the entity responsible for cost to be incurred is responsible for payment of the costs (cost responsibility follows cost incurrence) ("Cost Causation Principle"). Vote and Order Opening Investigation, D.P.U. 20-75, at 2-3, citing, e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 167 (2009); Gas Unbundling, D.T.E. 98-32-B at 31(1999); Boston Gas Company, D.P.U. 96-50 (Phase I), at 133-134 (1996); Electric Industry Restructuring, D.P.U. 96-100, at 51 (1996); Boston Gas Company, D.P.U. 93-60, at 331-337, 410, 432 (1993); Boston Edison Company, D. P. U. 1720, at 114 (1984); Generic Investigation of Rate Structures, D.P.U. 18810, at 14 (1977). In instances of public policy or where other discernable beneficiaries are identified, costs might be assigned and recovered from other than just the entity responsible for the cost. Id. at 3. For the interconnection of DER, consistent with the Cost Causation Principle, an interconnecting customer pays a Distribution Company for certain user fees and for system modification costs. Id. at 3, citing Interconnection Tariff, §§ 3.10 (Table 6), 5.0; see also, Distributed Generation, D.T.E. 02-38-B (2004). During the Department's examination of DER interconnection issues, the Department has acknowledged stakeholders' strong interest in the Department's investigation of alternatives to the Cost Causation Principle for the assignment and recovery of DER interconnection costs. Id. at 3.

The stakeholders' initial comments in this docket continue to advocate for alternatives to the Cost Causation Principle. The Department's Straw Proposal included several options to this end: including (1) a Capital Investment Project ("CIP") Fee; and (2) a Common System Modification ("CSM") Fee. The Straw Proposal defines a CIP as:

> a project proposed for cost recovery by a Distribution Company under the proposed distribution system planning process for the assessment of the interconnection and integration of DER… (Straw Proposal at 1).

CIPs proposed by a Distribution Company would be eligible for consideration of cost recovery through a Reconciling Charge and CIP Fees. The Straw Proposal defines "Capital Investment Project Fees" as fees:

> that would be assessed by a Distribution Company to an Interconnecting Customer associated with its Facility's pro-rata share of the costs of a Capital Investment Project, which has been approved by the Department and of which the Interconnecting Customer's Facility is a direct beneficiary (Straw Proposal at 1).

Projects may be identified either through the distribution system planning process described above, or through facility interconnection studies. All projects would need to obtain Department pre-approval for cost recovery before commencing.[3]

In the Straw Proposal, the Department indicates that, while the CIP Fee portion of the Straw Proposal coupled with existing cost allocation structures will be sufficient to address recovery of costs for interconnection of DERs, the Department is willing to consider whether a CSM Fee may be beneficial to address any common system modifications not included as Capital Investment Projects (Straw Proposal at 8). The term "Common System Modification Fee" is defined as:

> a fee that would be paid by all Interconnecting Customers, but which may be structured differently for different types of Facilities (e.g., Facilities subject to the simplified process versus those subject to the expedited or standard process), to offset the costs of System Modifications benefitting more than one interconnecting Facility or distribution customers at large, as described further below in Section III. A Common System Modification Fee would not be applied in situations involving System Modifications that benefit just one interconnecting Facility (id. at 2).

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[3] Additionally, to the extent transmission upgrades are included in the cost recovery mechanism, a filing to the Federal Energy Regulatory Commission would be required demonstrating no adverse impact to transmission customers.

The Department did not include a specific proposal for additional fees in the Straw Proposal. However, the Department indicated that it is interested in exploring whether there are different fee structures that may better facilitate the timely construction of the following types of distribution system upgrades that may benefit more than one interconnecting facility or customers at large: (1) substation transformer replacements; (2) reconductoring of distribution feeders; (3) distribution protection measures; and (4) transmission related upgrades triggered by resources interconnecting to the distribution system (id. at 9).

A. Summary of Stakeholder Comments

1. CIP Fees

The establishment of CIP Fees was supported in many comments as summarized below. The Department posed a specific question seeking opinions on whether a cap should be established on the dollar-per-kW billed to each facility that benefits from the Capital Investment Project. The stakeholders expressed varying views on this topic.

The AGO proposes that interconnection fees should be based on cost causation, so fee structures should be directly linked to the type of service a facility selects during the interconnection process (AGO Comments at 9). The AGO claims the Department's proposed $/kW fees for CIPs or CSMs can be interpreted as export fees, based on the potential costs caused by the maximum output of a DER during a worst-case scenario which disincentivizes export to the grid. (AGO Comments at 9). The AGO recommends charging facilities based on export capacity rather than installed capacity (AGO Comments at 9-10). The AGO asserts one way to incorporate this temporal cost causation concept into pricing structures is to charge exporting facilities system usage charges throughout the life of system through an export tariff as opposed to a lump sum fee when interconnecting (id. at 10). However, the AGO recognizes this may be beyond the EDCs' capability and, therefore, asserts a $/kW export fee may be the best option currently (id.).

The AGO claims the Department's proposed CIP provides perverse incentives to the EDCs' shareholders. As such, the AGO recommends two changes to the proposal: (1) require performance incentives on CIP utilization; and (2) reduce or eliminate ROE for investments that receive this special ratemaking treatment because risk is substantially lowered (AGO Comments at 11). Further, the AGO claims before system-wide CSMs fees are adopted, the Department and stakeholders should explore export related cost recovery and the feasibility and efficiency of export tariffs (id. at 11-12).

For long-term cost recovery, the AGO recommends it may be more efficient to use export fees through a distribution system tariff rather than an upfront fee. The AGO alleges dynamic pricing structures are critical to cost assignment and recovery, especially when excess export will be managed by EDCs over time, because export behavior can change over time. The AGO recommends the Department consider energy storage import tariffs to avoid unnecessary delays to storage deployment. Further, the AGO recommends the Department investigate the efficient pricing of export capacity to complement the pending CIP and CSM proposals. The AGO recommends this could be developed through technical sessions or a separate Export Working Group (AGO Comments at 12-13).

The DOER is unsure if there should be a price cap and emphasizes the distribution planning process should maximize upgrade mitigation and deferrals to help reduce the cost of hosting DER, and a metric should be explored to reinforce this goal. DOER emphasizes high price signals could result in developers going elsewhere leaving any upgrades to be recovered through general ratepayers (DOER Comments at 26).

National Grid opposes a cap on the dollar-per-kW billed to each Facility that benefits from the CIP because that would undermine the Cost Causation Principle and cost transparency goals that underlie the concept of a CIP (NG Comments at 14). National Gird proposes CIP fees remain constant and fixed for the earlier of the enabled capacity being fully subscribed or the end of the proposed 10-year reconciling charge period (id. at 4). National Grid recommends the Reconciling Charge be a separate line item on a customer's bill so that it is non-bypassable, exclude the charge from the net metering calculation and change the name to "CIP Factor" (id. at 5).

NECEC supports the Department proposal generally but suggests the proposal does not go far enough and developers still bear the majority of costs (NECEC Comments at 14). NECEC recommends allocating no cost to Interconnecting Customers for upgrades to existing infrastructure that are considered multi-value investments; and at least 70% of the costs for new distribution infrastructure included as CIPs should be allocated to ratepayers (id. at 15). NECEC asserts for local and bulk system transmission projects, 100% of the costs should be allocated to ratepayers (id. at 16). NECEC recommends there should be a cap on the dollar-per-kW billed to each facility that benefits from the CIP, which will result in a total dollar amount "ceiling" that an Interconnecting Customer is required to bear in the interconnection process (NECEC Comments at 17).

Pope recommends an either a flat fee or actual cost of interconnection if less than the capped, not to exceed cost of \$0.15 to \$0.20 per watt AC plus the project specific Point of Common Coupling cost (Pope Comments at 17). SEBANE supports the Department's CIP straw proposal. Further, SEBANE supports a cap to be applied to each facility that benefits from CIPs and the Department should consider varying levels of fees based on project size and type (SEBANE

Comments at 4). Finally, Unitil opposes a cap on the dollar-per kWh billed to each facility because it places an artificial ceiling (Unitil Comments at 7).

Eversource Reply Comments

Eversource continues to recommend that a portion of upgraded system capacity identified through a comprehensive distribution system assessment be allocated by substation (or a collection of inter-tied substations grouped as a study area) to specifically enable the interconnection of current and future DER facilities. The Enabled DER Reserve described in Eversource's initial comments is consistent with the Department's definition of a Capital Investment Project and the Company agrees that the cost associated with such upgrades should be substantially funded by interconnecting DER facilities through a $/kW fee structure consistent with the proposed CIP fee presented in the straw proposal. As will be discussed further with respect to Common System Modifications, the Company does not recommend that costs associated with upgraded capacity that also enhances the reliability, resiliency and operational flexibility of the electric power system be included in amounts recovered through CIP fees since such features provide benefit to all customers.

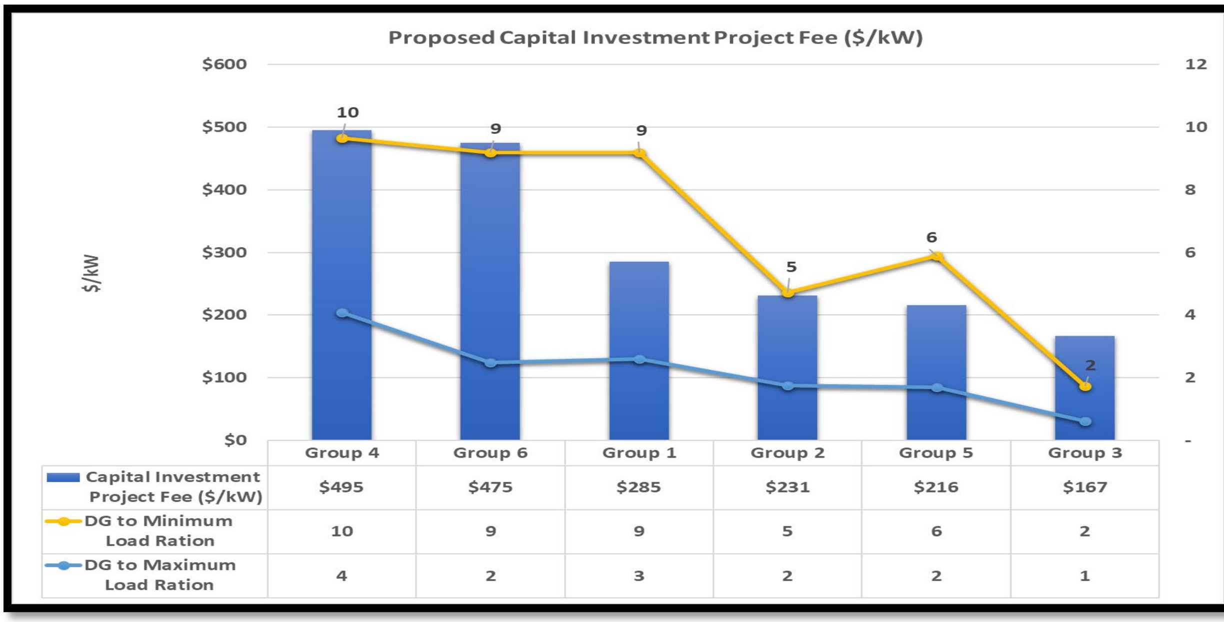
However, Eversource continues to recommend that an alternative to the Cost Causation Principal still provides appropriate and actionable price signals to DER developers. Having conducted significant DER Interconnection System Impact Studies, based on Eversource's preliminary assessment, it has identified a number of potential distribution upgrades and, using its proposed methodology to allocate benefits, has identified approximate allocation percentages of those costs to DER customers directly benefiting from those upgrades. The Company finds that where significant upgrades are necessary in areas where DER concentration relative to system demand is high – the resulting cost allocation percentage (per Eversource proposal) is also high.

As a result, Eversource discourages the Department from placing a cap on CIP fees or other interconnection costs. While the Company sees the benefit of upgrading these stations while enabling significant additional DERs in those areas, it is counterproductive as an EDC to have to go back to those same stations to rebuild them again with even potential higher concentrations of DERs in the future. However, recognizing that this situation might not be preventable, the bulk of those future upgrade costs should be borne purely by DER customers to incentivize efficient infrastructure decisions. The Company therefore recommends the Department decline to establish a fixed cost-sharing structure and instead determine DER cost responsibility based on parallel benefits, if any, associated with system upgrades that enable the interconnection of DER facilities.

In stipulating DER facilities pay a fixed percentage toward the cost of system upgrades or placing a cap on the contribution, the Department could create scenarios in which non-DER customers would be required to support the cost of investments that provide little to no parallel benefits to the electric power system. Such a cost allocation would result in EDC customers inappropriately and inefficiently subsidizing the cost of system upgrades that only enables DER facilities to interconnect and operate to generate revenues for system owners.

Mitigating useful price signals would also be counterproductive to the long-term goals of most efficiently achieving the Commonwealth's clean energy and climate goals and maximizing the net benefits of state-supported clean energy investment. Despite the emerging cost barriers to DER interconnection that this investigation seeks to address, there continue to be differences in costs required to enable the interconnection of DERs on various portions of the electric power system. Massachusetts should continue to seek to minimize the total costs of achieving clean energy goals by encouraging DER developers to seek out locations where resources can be added at lower cost. Maintaining price signals will advance important goals of encouraging cost-efficiency and is unlikely to prevent the Department from successfully addressing current barriers to DER growth with an alternative to the cost causation principal. The Company has provided illustrative examples below in order to demonstrate how its recommended alternative to the cost causation principal can effectively mitigate potential cost barriers for a large volume of DER capacity by reasonably accounting for parallel benefits of system upgrades. The recommended approach will still result in variation in costs allocated to individual DERs or groups of DERs and preserve appropriate price signals.

Figure 1 - Representative Group Study Cost per kw vs Load Ratio



	Group 4	Group 6	Group 1	Group 2	Group 5	Group 3
Capital Investment Project Fee ($/kW)	$495	$475	$285	$231	$216	$167
DG to Minimum Load Ration	10	9	9	5	6	2
DG to Maximum Load Ration	4	2	3	2	2	1

Based on the Company's preliminary Group Study analysis, the Eversource cost allocation proposal is likely to result in reasonable cost allocation while not abandoning prices signals necessary to incentivize efficient DER buildout in appropriate areas. For example, Figure 1 above shows potential project fees by group that are representative of areas with high DER penetration. This figure is based on the Company's preliminary findings from the ongoing current group studies in the South Eastern area of Massachusetts. High-level cost estimates[4] are shown by group together with minimum and maximum load ratios per group. The minimum load ratios are calculated as the ratio of the Sum of Total Large plus Small DG in the group (including Existing, Queued DG as well as projected Small DG) divided by the Sum of Minimum load measured at each substation during times of high DER penetration.

This figure demonstrates that in general Eversource's approach results in lower interconnection costs in areas where DG growth relative to system demand is low – providing an interconnection cost incentive to developers to develop DG where load density is higher:

- The lower the DG relative to Minimum and Maximum loads in specific areas – i.e. areas with higher loads but lower proportionate DG growth, the lower the projected $/kW CIP Fee;
- Correspondingly, the higher the DG relative to load the higher the $/kW CIP Fee.

The Company has observed some outliers – i.e. lower $/kW CIP Fee in an area with High DG/Load ratio or relatively higher $/kW CIP Fee in an area with relatively lower DG/Load ratio. For example, the cost for Group 1 is significantly lower than the average especially relative to Group 4 and 6. This lower cost results from the fact that the existing distribution infrastructure has higher capacity resulting from recent upgrades and is therefore highly reliable already requiring minimal distribution bulk substation upgrades. Similarly, Group 5 benefits from recent upgrades completed in one of the two distribution bulk substations that make up the group, resulting in a stronger existing system and less resulting required upgrades to reliably integrate DG. As a result, Groups 1 and 5 have a relatively lower $/kW CIP Fee despite relatively higher DG/Load ratios benefiting from the existing strength of the local distribution system. This further demonstrates

[4] For illustration purpose only, high level order of magnitude that does not include detailed cost estimate to be developed after engineering review/studies.

that Eversource's proposed cost allocation proposal incentivizes efficient distribution infrastructure buildout – by providing an interconnection price signal to develop DG where infrastructure has already been built to higher capacity and can reliably integrate DG.

2. Common System Modification Fees

DOER recommends the Department should establish a minimum CSM Fee for Expedited and Standard Facilities that is based on the DER Facility's impact to the grid (DOER Comments at 29). DOER reiterates its earlier proposal and states its "nameplate size" aspect of its proposal could serve as a minimum fee. DOER asserts the export capability should be the primary driver in setting the CSM fee (id. 29-30). DOER continues to recommend the cost basis for establishing the CSM Fee could be established to only recover the average costs of upgrades not included in CIPs (id. at 30). DOER claims the fee sends clear price signals because it demonstrates the impact on the distribution system. DOER recommends that the fee be weighted 20% on nameplate capacity and 80% on export capacity (id.).

DOER proposed CSM fees which are not applied to upgrades for small BTM facilities could be applied to CIPs which are under-recovered by CIPs following their 10th year. DOER states this would mitigate risk of ratepayer costs associated with CIP (DOER Comments at 31). DOER recommends that the Common System Modification Fee be pre-approved at a higher level, such as pre-approving the use toward service transformer replacements, and for 3V0 improvements to substations which are not otherwise identified for upgrades in the system planning process. DOER claims this would provide greater flexibility to the EDCs to cover common upgrades and continued DER deployment (id. at 32). DOER recommends the CSM Fee be prioritized to funding upgrades necessary for the interconnection of DER sited at customers with existing load. Further, DOER recommends all capital upgrades be subject to Department review and approval (id. at 35).

IREC suggests allocation of costs for CSM only be done for larger Expedited and Standard process projects. IREC suggests the fixed-fee-per-kW approach. To allow for price signals, IREC suggests geographic pricing. However, IREC suggests projecting future CSM under this approach would be complicated and suggests a better way would be establish a fixed price based on the simplified project method: use the previous year's Common System Modifications and number of projects to establish a fee for the next year's applications (IREC Comments at 15). The fee should be based on export capacity not nameplate and the fee should apply to individual projects and group study projects (id. at 16).

NECEC clarifies a CSM should not include system improvements otherwise needed for reliability or asset conditions. NECEC suggests the CSM fee be neither flat nor minimum but, should be calculated as a pro-rata sharing of CSM costs (NECEC Comments at 21-22). NECEC suggests each benefitting large Interconnecting Customer would pay a maximum of 30% of its allocated "Headroom Share," capped at $300/kW and not to exceed a Capital Investment Project Fee and CSM fee cumulative cap of $1,500,000 per Interconnecting Customer. The balance of costs (70%) would be allocated to the rate-base through the EDC's reconciling mechanism (id. at 22).

Pope suggests a minimum CSM fee of $0.10 per watt AC for projects over 500kW. Pope asserts market signals do not exist because of oversaturation most applications need to be studied (Pope Comments at 19 Pope recommends a maximum CSM fee of $0.20 per watt AC (id. at 23). Pope argues CSM fees should be based on nameplate capacity (id. at 23).

For determining which upgrades should be covered by collected funds, Pope asserts reconciled cost roll up in the same account(s) as the locationally based upgraded feeder, substation component, or transmission upgrade and if the Flat Fee, Minimum Fee or Maximum Fee pays for all of the upgraded cost, then there should be a record of such occurrence (Pope Comments at 24) Pope recommends upgrades covered by the CSM fees would be subject to Department approval.

SEBANE supports a fixed dollar-per-kW fee for CSM fee collection for expedited and standard interconnection process facilities. SEBANE recommends establishing a stakeholder collaborative or quarterly technical conference to share planning studies, discuss outcomes and receive stakeholder input. SEBANE supports the adoption of a cost-sharing mechanism based upon the true cost to interconnect that does not exceed the fixed dollar-per-kW fee (SEBANE Comments at 7).

Unitil does not support a minimum CSM fee because those projects will be covered by the CIP fee and a CSM fee would undermine the price signal of a CIP Fee and inappropriately socialize costs (Unitil Comments at 11). Unitil recommends that there should only be one method for cost allocation for system modifications that benefit expedited or standard DER applicants and that is the CIP fee.

Eversource Reply Comments

As noted above, a number of stakeholders recommend that an alternative to the Cost Causation Principal which considers broader system benefits is appropriate for Massachusetts DER interconnection and consistent with the Commonwealth's clean energy policies. The Company agrees that cost allocation which recognizes parallel system benefits of upgrades to the electric power system is appropriate, and also expects it will be necessary in order to address system upgrade costs that are emerging today with higher levels of DER penetration.

In its straw proposal, the Department characterized CSMs as system upgrades that benefit more than one interconnecting facility *or distribution customers at large*. The Company recommended in its previous comments that the Department refine and specifically differentiate

CSMs from Capital Investment Projects. The Company reiterates this recommendation in these comments. The Company expects that all system upgrades identified through the proposed planning process and proposed for recovery through project fees or special ratemaking treatment will benefit more than one interconnecting DER facility. The Company recommends that the costs of upgraded capacity that only benefits interconnecting DER facilities be substantially recovered through CIP Fees as discussed previously. Therefore, the definition of CSMs would be constructively refined to include only system modifications which also specifically benefit customers at large. Eversource expects that benefits to customers at large would frequently be associated with enhancements to the reliability, resiliency and operational flexibility of an electric power system which will be critical to advancing the State's clean energy and climate goals.

System capacity associated with an Operational Reserve described in the Company's initial comments is similar to the description of Multi-Value Investments in the comments of NECEC. It is also different from NECEC's proposed Multi-Value Investments in that the Operational Reserve contemplated by the Company is based upon consideration of factors that extend beyond load growth. However, the Company is in agreement with NECEC that costs of upgraded capacity that broadly benefits all customers should not be allocated to DER facilities under an updated Cost Causation Policy. Eversource recommends that costs of CSMs be recovered from all customers who benefit from use of the electric power system through the Reconciling Charge included in the Straw Proposal.

The Company also recommends the Department ensure that any refined definition of CSMs adequately support the allocation and recovery of transmission system upgrade costs. A number of stakeholders that provided comment on the Department's Straw Proposal agreed that transmission studies should be included in the proposed system planning process. The Company agreed as well, explaining that understanding transmission impacts will be key in identifying suitable infrastructure upgrades needed to enable an increased penetration of DER. The costs of transmission system upgrades (including ongoing transmission operating costs) to support further DER enablement are likely to be substantial and would be a barrier to further DER integration if the Department does not adopt a cost allocation approach that appropriately recognizes parallel benefits to the electric power system that they provide. The Company expects that transmission upgrades which support higher flows of DER injection out of bulk substations will also substantially improve the reliability and operational flexibility of the electric power system. Accordingly, the Company recommends that substantially all transmission system investment be considered within the operational reserve category of system upgrades, be classified as a CSM that provides benefit to all users of the electric power system and be recovered through the Reconciling Charge.[5]

b. Simplified Facilities

DOER recommends a fee for Simplified projects that is variable based on the relative impact of the facility on the distribution system, and substantially decreased for resources with minimal or no exports (DOER Comments at 27). DOER recommends the fee address replacing service transformers and barriers to interconnection (id. at 27-28).

IREC recommends that projects in the Simplified interconnection process be exempt from the proportional share of the CIP fee and instead set a fixed fee (IREC Comments at 9). Further, IREC recommends no fee be charged to non-exporting projects (id. at 10). IREC suggests setting

[5] As noted by the Department in D.P.U. 19-55-C at 41-42, "because the estimates and actual costs for [Affected System Operator] studies and system modifications are determined by the ASO, they are not bound by the same limitations as distribution-level studies and resulting system modification costs. Consistent with our long-standing precedent, the interconnecting customer bears the costs associated with its interconnection, which includes any ASO study or system modification costs triggered by the interconnection. SMART Tariff, D.P.U. 17-140-A at 156 (2018); Retail Access for Competitive Suppliers of Renewable Energy Generation Attributes, D.P.U. 08-52, at 18 (2014); Aquarion Water Company of Massachusetts, Inc., D.P.U. 11-43, at 250 (2012).

the fee by dividing the previous year's upgrade costs attributable to or consumed by Simplified Process projects by the number of such projects in that year (id. at 11-12).

National Grid supports a CSM fee for Simplified Process projects (NG Comments at 26). National Grid proposes setting a minimum $/kW fee per application that would cover the cost of the applicant's minor System Modifications up to a fixed amount representing the typical cost for such minor System Modifications, with the applicant covering any costs above that amount as a direct System Modification payment in rare scenarios. The fee would be payable with the application. The amount of the fee could be adjusted annually based on actual spend (id. at 27). National Grid proposes the following be funded by the CSM fee for facilities using the simplified process: overhead service transformer upgrades, secondary voltage system reconfiguration or service reconfiguration, service upgrades or new services required to enable interconnection. National Grid also recommends several upgrades be excluded from CSM fee funding (id. at 28-29).

National Grid does not support using fees collected from simplified process facilities to be used to offset costs of CIPs (NG Comments 29-30). National Grid agrees with the Department that the proposed CIP Fee coupled with the existing cost allocation structures, including the Cost Causation Principle and Group Study, is sufficient to address assignment and recovery of costs for the interconnection of DER and endorses the CIP Fee over a CSM Fee for Expedited and Standard Facilities (id. 33-34). National Grid is opposed to CSM fee for expedited and standard facilities because it masks costs triggered. Additionally, a maximum or fixed fee effectively would be a permanent subsidy.

NECEC acknowledged the benefits of a CSM for Simplified facilities, but noted they should be $20 per kW and capped at $500 (NECEC Comments 19-20). Pope believes Simplified projects should also pay a fee to interconnect; Pope recommends a flat fee of $150 for small projects under 10kW and $300 for those projects 10kW to 25kW and projects 25kW to 60 kW would pay a flat fee of $0.10 per watt AC and projects greater than 60 kW to 500 kW would pay $0.15 per watt AC (Pope Comments at 18).

SEBANE agrees with the Department that a CSM Fees may be appropriate as more simplified projects are planned and executed, but notes that the Department should ensure reduced interconnection delays for simplified projects. SEBANE also notes it could support the establishment of a fixed fee for simplified process that includes a cap (SEBANE Comments at 5).

Unitil supports a CSM for Simplified process projects. Unitil proposes that the forecasted DER and historical system modifications and average existing transformer size be used to estimate the number of Simplified Interconnecting Customers that would require system modifications. A fee based on $/kW (Nameplate) would be assessed to all Simplified Interconnecting Customers at the time of approval to interconnect. Additional costs (not covered by the Simplified CSM fee) would also be assessed to individual Interconnecting Customer as required for their application (Unitil Comments at 9). Unitil asserts the CSM fee for Simplified interconnection process should not offset CIP costs (id. at 9-10).

Eversource Reply Comments

Eversource supports the implementation of reasonable fee structures for facilities using the simplified process. The Company agrees that the interconnection of such facilities occasionally requires overhead service transformer upgrades, secondary voltage system reconfiguration or service reconfiguration, service upgrades or other new services. While the total costs of these upgrades are substantially less than those associated with facilities using the expedited and standard process, they are costs which are most appropriately funded by the customers whom their installation benefits.

National Grid has proposed an equitable and administratively reasonable framework that would be appropriate for the Department to substantially implement. Eversource agrees that costs recovered through a fee structure for facilities using the simplified process should be kept separate from the CIP framework for facilities using the expedited and standard process. The Company also agrees with National Grid that maximum or fixed fee structures are not preferred.

As an administrative matter on this topic, Eversource recommends that common definitions and terms be developed so that they can be applied consistently where ever possible in order to avoid confusion amongst stakeholders. The Department and stakeholders have described a potential fee structure for facilities using the simplified process as a CSM fee. Eversource has previously recommended that the definition of CSM be specifically defined to include only system upgrades which benefit all customers broadly. The types of upgrades proposed for inclusion in the fee structure for facilities using the simplified process are unlikely to provide such benefit. Accordingly, it may be constructive to establish separate and unique definitions for elements of the fee structure for facilities using the simplified process.

III. DISTRIBUTED ENERGY PLANNING AND RESOURCE REQUIREMENTS

A. Summary of Stakeholder Comments

The AGO recommends extensive stakeholder involvement in the planning process. The AGO proposes a pre-implementation process to determine current functionality by distribution company and the creation of a "DER Integration Roadmap" to standardize DER treatment (AGO Comments at 4). As proposed by the AGO, a DER Stakeholder Working Group will draft a public document detailing a state-wide vision for the Commonwealth with respect to distribution system planning and cost allocation and the EDCs will create a report on its distribution system and capabilities. Then, each EDC will create an "action plan" to close any gaps between the stakeholder report and the EDCs' capabilities (id. 4-5). The EDCs' action plan would be subject to review by subject matter experts.

The AGO proposes expanding the aforementioned "vision" into the "DER Integration Roadmap" to include a framework of technological, process, and regulatory considerations for the EDCs to use to inform their individual ten-year assessments. Specifically, the AGO seeks to have the DER Integration Roadmap include the following tasks: establishing a common baseline for DER standardization; developing recommendations for default and/or unattended functions that leverage advanced DER; developing recommendations for monitoring and control communications requirements to interact with advanced DER; developing recommendations for advanced bulk electric system reliability settings within advanced DER; and developing recommendations for advanced, interactive settings within advanced DER. (AGO Comments at 5). The AGO recommends that the Pre-Implementation and DER Integration Roadmap processes be led by a non-EDC facilitator with subject-matter expertise (id. at 6).

DOER supports assessing projects that provide broader benefits beyond enabling incremental DER capacity. DOER provides examples of benefits such as reliability, resilience and emissions reduction (DOER Comments at 23). DOER notes ideally, DER planning would transition to standard utility practice within a PBR and not require separate and special ratemaking treatment in the future. However, DOER supports the Department's proposal to adopt a special ratemaking treatment option with pre-approval for investments needed to integrate DER and DERs as it may help incentivize the EDCs to make needed investments.

IREC is generally supportive of the Department's proposed DER Planning Requirements. IREC advocates for the DER planning process to exclude regular course of business capital investments, be designed as accurately as possible without overestimating the amount of required capacity upgrades and exclude any investments that would result in minimal or nominal capacity upgrades (IREC Comments at 5). IREC encourages a stakeholder process for development and approval of a ten-year distribution assessment (id. at 10). However, IREC cautions the planning process may identify more upgrades than the market can bear. As such, IREC proposes the EDCs allocate a portion of subscribed capacity fees to ratepayers to allow continued DER growth (id. at 8).

National Grid generally supports the proposed DER planning process (National Grid Comments at 3). However, National Grid proposed several modifications. National Grid proposes to establish zones for CIPs and CIP fees based largely on the company's 48 planning areas. The CIP fees would be calculated net of costs attributable to planned improvements and the company would take account of allocations for improvements due to DER upgrades that benefit all customers.

In addition, National Grid supports the distribution system assessment identifying projects that provide broader benefits beyond enabling incremental DER capacity (NG Comments at 13). The set of suggested benefits are: DER enablement, EV enablement, heat electrification enablement, and traditional system safety and reliability needs (id. at 13-14). National Grid asserts cost assignment to each benefit, except through a simple percentage assignment, would not be possible. National Grid has not determined an appropriate cost assignment method for integrated planning but is receptive to a variety of simplified methods that approximate cost causation principles without requiring overly burdensome calculation methods (id. at 14).

NECEC asserts the assessment of distribution system upgrade benefits should be informed by the Commonwealth's overall clean energy and climate goals and assess: (a) performance improvements, (b) quantity of incremental DER that can be cost-effectively interconnected, (c) changes in patterns of consumption due to beneficial electrification that can be accommodated, (d) the flexibility of the system and its ability to accommodate unanticipated future needs, (e) system resilience and ability to meet environmental challenges (NECEC Comments at 11-12). NECEC suggests the EDCs conduct a quarterly technical conference to share planning studies and outcomes and receive stakeholder input (id. at 13).

Pope supports the distribution system assessment identifying projects that provide benefits beyond enabling DER. Pope suggests the concurrent development of electrification of building and transportation (Pope Comments at 16). SEBANE supports the identification of projects that provide broader benefits beyond enabling DER capacity (SEBANE Comments at 3). SEBANE suggests evaluating the benefits through annual savings for customers, carbon and GHG reductions, and improved interconnection application times (id. at 4). SEBANE generally recommended stakeholder involvement in the planning process and in the development of cost recovery frameworks.

Unitil states a project should be consistent with current system planning principles and processes and any system forecast and planning should include EV, heat electrification, asset condition information, and reliability performance information inputs (Unitil Comments at 6). Unitil recommends the EDCs work collaboratively with the Department to identify a way to quantify benefits. Unitil does not provide a cost assignment and recovery method but recommends the method be straightforward and align with cost causation principles (id. at 6-7).

B. Eversource Reply Comments

The Company supports establishment of a stakeholder process specifically as it relates to development of distribution upgrades required for reliable integration of DER eligible for special ratemaking treatment with cost recovery through a Reconciling Charge. Enabling greater stakeholder participation in the EDC's rolling 10-year Distribution Planning assessment related to integration of DER that is the subject of this proceeding will support the achievement of the Commonwealth's clean energy and climate policy objectives. It is important to note that the Company's Distribution upgrades that solely result from Eversource's base load forecast scenarios are otherwise included in the Company's Distribution Capital Plan cannot be the subject of this stakeholder process, as decisions related to the base capital investments that are necessary to ensure the safe and reliable operation of the electric grid rest squarely with the EDCs. The EDCs require extensive capital investments be made to ensure the continued safe and reliable operation of the system, absent the DER projects and processes that are the subject of this proceeding. The EDCs must ensure the timely execution of these projects and therefore cannot subject the review, approval, or prioritization of base Distribution Capital projects to a stakeholder process. It's important to note to that end that the EDCs base distribution capital expenditures would not be eligible for the special ratemaking treatment being considered in this proceeding, nor will the cost of these projects be allocated directly to DER customers.

As will be discussed in more detail herein, the intent of the stakeholder process[6] is to give stakeholders insight into scenarios and modeling assumptions and to facilitate stakeholder input on study results, findings and recommendations relating only to those projects necessary to achieve

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6 The following roles and responsibilities are defined as part of the overall stakeholder process:

- **Facilitator:** An experienced professional retained by the EDCs with approval of the Department to organize and run the stakeholder meetings, engage with the EDCs and stakeholders outside of the planned meetings, and drive consensus between the EDCs and stakeholders.
- **EDC Planners:** EDC planners responsible for various aspects of the panning process will be available to present plans and results and discuss findings with stakeholders.
- **Subject Matter Experts:** A designated individual with domain expertise on various steps of the planning process and the plans and findings presented at the meetings.
- **Interested Stakeholders –** Designated individuals from DER development companies with domain expertise in Distribution system planning and engineering.

the Commonwealth's policy objectives. The stakeholder process should not aim to supersede, impede or delay the EDCs' well-established distribution planning processes for system investment to address the safe operation of the distribution system, reliability, base load growth, and other non-DER drivers, but should support and compliment the EDCs' comprehensive planning process for DER-driven system expansion by giving stakeholders the ability to advise on certain aspects of this specific planning process.

In its December 2020 filing, the Company proposed a comprehensive 10-year distribution assessment to be performed on a yearly basis, that considers short-term and long-term upgrades to the EPS *driven by DER growth* to meet the capacity, reliability, and operational flexibility requirements to serve all customers. The assessment generally includes the following steps:

1) **Define and establish planning scenarios**, sub regions or study areas, modeling assumptions and the scope and need for system expansion, considering N-1 operational requirements. Areas of the system that experience high DER growth leading to station saturation and the accompanying technical impacts such as reverse power flow, thermal overloads, voltage violations, elevated risk of transient over voltages, risk of islanding, etc. are identified as potential study areas for DER planning assessment. Planning scenarios and study areas are developed based on the amount of existing and in-queue DER relative to the ability of the station to absorb and integrate the DER, as well as the ability of the electrically connected group of stations to safely and reliable provide service to the DER and load customers under N-1 contingency situations.

2) **Forecast and estimate aggregated output** for existing and future large- and small-scale DER, for the study area. This begins with station-by-station probabilistic load forecasts that incorporate the historical load trend, existing and in-queue DER and probability of DER adoption to evaluate the performance of the system and assess the need for substation capacity upgrades.

3) **Assess impact of high DER penetration** on the bulk system and distribution feeders. This analysis leverages the same advanced models, planning tools and methodologies currently used in steady-state and transient analyses to assess system deficiencies and needs for providing adequate capacity, reliability, and voltage and power quality to all customers. Since the prior steps would have identified areas and sub-areas that are heavily impacted by DER growth and developed appropriate forecasts, this assessment is specifically focused on these DER-driven scenarios and study areas as opposed to load-growth or other non-DER-driven scenarios which EDCs already plan for that

today and develop investments in their Base Capital Plan to ensure safe and reliable service.

4) **Determine comprehensive transmission and distribution upgrades** required to accommodate existing and future DER and maintain safe reliable operation. Once system impacts and needs are determined, mitigation measures and system upgrades are developed to accommodate existing, planned and forecasted DER. The same advanced models, planning tools and methodologies applied to determine the system needs are leveraged to assess and confirm the efficacy of these measures.

5) **Define and allocate system capacity** and assign appropriate cost recovery mechanisms. This step will attempt to determine the portion of DER-driven investments that provide operational flexibility and ensures reliability for all customers, especially under N-1 operation. This portion of the upgrades will be assigned to a reconciling charge to be recovered from ratepayers above and beyond capital projects for non-DER growth DER integration and system reliability (which is a separate on-going planning process). The balance of the DER-driven investments will be assigned to a Capital Investment Project charge to be recovered directly from DER customers.

While the Company does not object to plans, assumptions and projects resulting from this assessment being subjected to the stakeholder input process, a clear distinction must be made between these DER-enabling projects and 1) projects that are already established as part of the base capital plan, and 2) projects that are needed and will be established to address load safety, growth and/or reliability needs. Correspondingly, where Eversource identifies that an already identified upgrade needed to meet load growth and/or its reliability needs – that is already included in its base capital plan, it does not propose to allocate a portion of the cost of those projects to DER developers.

As discussed in the Company's December 2020 filing, Eversource supports a stakeholder process to guide DER forecasting and associated planning process to develop distribution infrastructure upgrades for reliable integration of DER. Figure 2 below summarizes the proposed yearly planning process, including planning activities milestones and stakeholder input meetings. As shown in Figure 2, the process follows an overlapping 14-month calendar, beginning in March with the initial EDC Planning Stakeholder Meeting (I). However, the initiation could be different for each EDC, subject to their planning cycle. For Eversource, a March start is appropriate, as this gives our planners several months before the initial meeting to develop models, assumptions, base case scenarios and forecasts based on the prior year's full load cycle. As shown in Figure 2, the EDCs will post planning scenarios and modeling assumptions two weeks before the initial EDC Planning Stakeholder Meeting. At this stakeholder meeting, the EDCs will engage stakeholders to solicit input on the scenarios and assumptions and obtain data and information to potentially refine forecasts. It is critical that this stakeholder process include defined timelines to ensure that the necessary system upgrades are not unnecessarily delayed by the process.

Eversource proposes the following touchpoints throughout the planning cycle for stakeholder participation:

1. March Stakeholder Meeting:

At this stakeholder meeting, Eversource proposes to present its planning scenarios and specific sub-regions included in the applicable year scope. It will also present associated modeling assumptions, forecasts and underlying data and methodologies. This stakeholder meeting provides an opportunity for all stakeholders to guide and inform forecasting assumptions – specifically as it relates to EDC assumptions of DG forecast at specific stations included in the applicable year scope and its alignment with the Commonwealth's climate policy objectives. The Company recognizes that climate policy objectives – and associated DG forecasts and methodologies are typically at a state or regional level while Distribution Planning at a collection of distribution stations included in the applicable year scope requires a much more granular view – typically at a station level. The Company proposes a Facilitator role at these stakeholder meetings who would drive stakeholder consensus and assist with aligning the EDC station level forecasts with the stakeholder input on state/regional level forecasts. Stakeholders would also have an opportunity to provide input on underlying data sources as well as methodologies adopted in the Ssation-level DG forecasts.

It should be clear – so as to not paralyze the Distribution Planning process, that once the methodologies, underlying data sources and associated DG forecasts are locked, that stakeholders do not have continued ongoing ability to alter these forecasts once planning analysis commences – to drive different outcomes. We therefore propose that two weeks after this March Stakeholder meeting, written responses shall be provided by the EDC planners to all participating stakeholders on an adopted methodology based on input from the Facilitator and SMEs along with associated rationale, which shall be used by the EDC planners to identify outcomes.

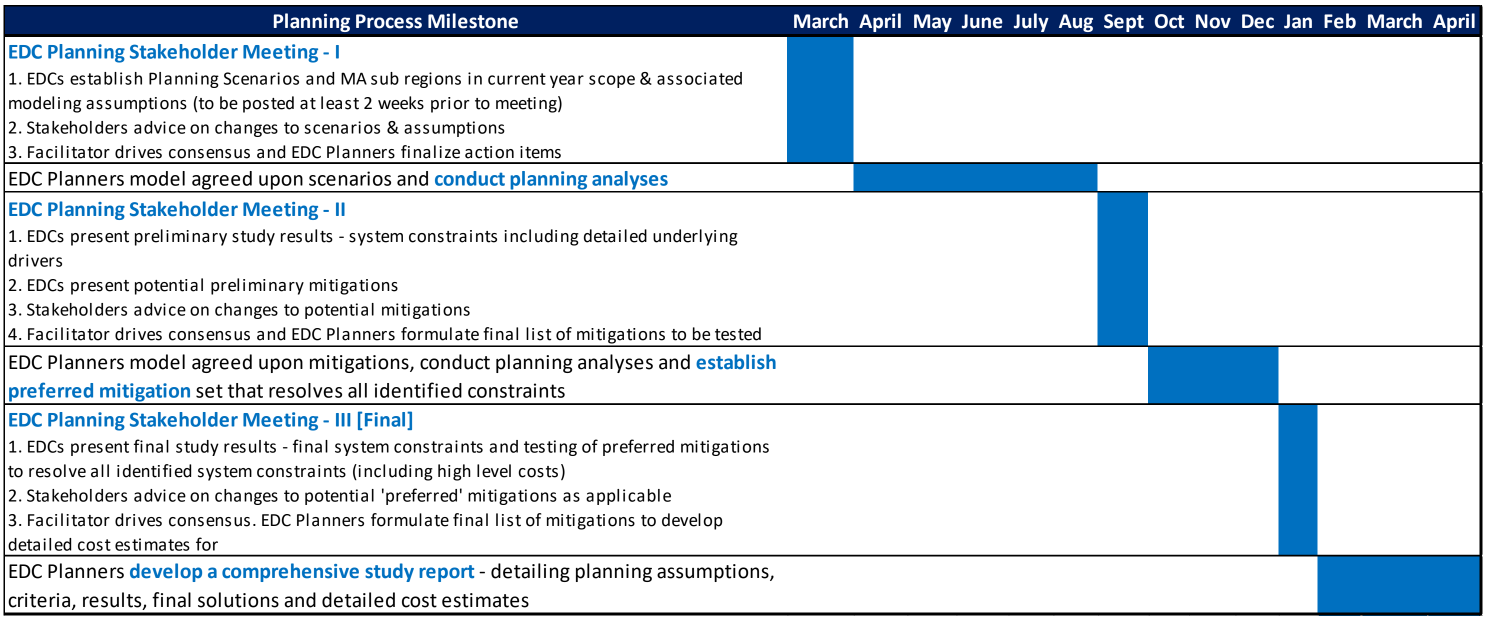
2. September Stakeholder Meeting:

At this stakeholder meeting, Eversource proposes to present preliminary study results – system constraints resulting from DER forecasts as well as its preliminary proposed mitigations. This stakeholder meeting provides an opportunity for all stakeholders to guide and inform distribution infrastructure solution development as well as any other applicable solutions that may be feasible and implementable in time to allow for DER integration. Similar to the March meeting, a two week period will be provided after the September meeting for EDC planners to provide written responses to all participating stakeholders on final list of system constraints deemed valid to pursue solution development and associated rationale. After that communication, planning analysis to test mitigations to all valid system constraints shall commence without further input..

3. January Stakeholder Meeting:

At this stakeholder meeting, Eversource proposes to present the final study results, full testing of its recommended mitigations to resolve all outstanding system constraints as well as high level costs – and associated allocation among CIP Fees and Reconciling Charge. This stakeholder meeting provides an opportunity for all stakeholders to guide and inform selection of final solutions set to meet system planning needs as well as their input on that quantification of benefits by the EDCs and associated cost allocation.

Figure 2: DER Planning Stakeholder Process



The stakeholder process would provide important information and context to the DER community on DER system impacts and reliability considerations and also provide valuable feedback to the Company on the solutions and mitigation plans developed to address these impacts. The stakeholder process would provide a mechanism for developing consensus around the need to balance investments to accommodate DG growth with investments to promote safe, reliable operation for all customers. The process chart above provides and overview of the planning steps, the timeline, and the proposed role of stakeholders in the planning process.

IV. DYNAMIC CURTAILMENT, POWER CONTROL AND EXPORT PRICING ALTERNATIVES

The Attorney General's cost allocation proposal submitted in D.P.U. 19-55 recommended adopting arrangements to control and manage power export as a means of mitigating or avoiding

System Modification costs for medium and large DG Facilities. See D.P.U. 20-75 Order, Att. B-1 (AGO cover letter) at 3. Under the Attorney General's Power Control Limiting program, a DER applicant would propose to limit its capacity or its imports and exports to avoid triggering system upgrades. See Order, Att. B-1 (AGO att.) at 16.

A. Summary of Stakeholder Comments

For a short-term solution, IREC generally supports the AGO's dynamic curtailment and power controls programs. To share costs, IREC suggests the group study program could suffice but, is also open to the AGO's reimbursement proposal (IREC Comments at 17). Additionally, IREC is open to Eversource's reimbursement proposal (id. at 18).

National Grid is supportive of the AGO's two shorter term proposals to allow power control limiting and conceptually supports dynamic curtailment (NG Comments at 3). Currently, National Grid offers power control limiting to new applicants who have not yet finalized project design (id. at 36). National Grid agrees that when the infrastructure for dynamic curtailment has been developed, dynamic curtailment could be a useful interconnection tool in certain circumstances, such as in areas of moderate DER saturation. National Grid does not consider dynamic curtailment to be a method of cost allocation (id. at 38).

National Grid provides a list of hardware and software that would be needed to implement (NG Comments at 38-40). Further, National Grid asserts the ISA would need to be updated to allow for the AGO's proposed program (id. at 40-41). National Grid states it currently does not have the ability to implement the Program and the most significant challenges would be procuring the Control Technology and designing the two-way secure Gateway solution (id. at 41-42). National Grid provides details on the ARI pilot program proposed in New York which test its ability to develop and manage flexible interconnections from several customer-owned renewable

DER facilities on a single distribution circuit (id. at 44).

NECEC claims the AGO's proposals address a specific problem and do not offer a broad solution claiming neither will have a significant effect on interconnection challenges. Additionally, NECEC recommends the Department reject the AGO's reimbursement approach (NECEC Comments at 25-26).

Pope supports the AGO's Strategen Consulting report, which called for a new cost allocation method given the evolving policy landscape. Further, Pope supports the AGO's report on differentiating between project type and size because they provide different benefits (Pope Comments at 9). For short term solutions, Pope supports the AGO's power control limiting program, if economic curtailments are modeled within certain financial parameters (id. at 24-25). According to Pope, the power control program should only be for new customers.

Unitil agrees that limiting the output of a Facility may reduce the amount of system modifications required but, Unitil argues it does not increase the Hosting Capacity of the circuit. Unitil does not agree with the Attorney General's suggestion that power control limiting is a manner of cost allocation that appropriately assigns costs to direct beneficiaries and avoids assigning costs to non-beneficiaries (Unitil Comments at 15). Unitil states it does not have the ability to implement the AGO's proposed dynamic curtailment because of the lack of DERMS functionality (Unitil Comments at 18).

B. Eversource Reply Comments

Eversource appreciates the AGO's apparent desire to explore alternative solutions that may create opportunities to mitigate the scale of system upgrades needed for further DER growth, including alternatives that seek to do so with efficient price signals. However, for a number of technical and financial reasons discussed below Eversource does not find the AGO's recommendations to be practical solutions for enabling the continued near-term growth of DG in the Commonwealth.

As an initial matter, the scale of emerging constraints that must be addressed to sustain DER growth far exceed what could be reasonably addressed through power control limiting or dynamic curtailment measures. Figure 3 below summarizes the results of a study showing the generation constraints for a representative substation in the Southeastern area of Massachusetts. The substation currently has about 3.7 MW of behind-the-meter solar, and 67 MW of utility scale solar installations in queue. Furthermore, load growth at the station is forecasted at a low 0.07 MW per year.

The study uses the assumptions in Table 1, for the various DG already in queue to be connected within 6 years. This <u>does not</u> include any other and new applications that have yet to be filed; therefore after 2027 the PV Queue Forecast is zero. This is a conservative assumption, given that any further applications over the next years would consequently drive up the cumulative PV queue over the next 10 years.

Table 1: Representative Substation PV Queue and Load Growth by year

Forecast Year	PV Queue Forecast per year (MW)	PV Queue Scenario Cumulative (MW)	Load Forecast per year (MW)	Load Forecast Cumulative (MW)
2021	18.7	18.7	0.07	0.07
2022	11.0	29.7	0.07	0.14
2023	11.0	40.7	0.07	0.21
2024	11.0	51.7	0.07	0.28
2025	10.0	61.7	0.07	0.35
2026	10.0	71.7	0.07	0.42
2027	0.0	71.7	0.07	0.49
2028	0.0	71.7	0.07	0.56
2029	0.0	71.7	0.07	0.63
2030	0.0	71.7	0.07	0.7

When using the historic substation data at a 15-minute resolution for the entire year of 2020, load profiles for the station can be created for each forecast year.[7] As a result, new yearly profiles can be created for each forecast year using the Eversource Non-Wires Alternative (NWA) Screening Tool. The tool is then able to identify the magnitude and energy constraints of the station to enable scaling of an NWA solution. Table 2 shows the overview by year, specifically the yield of curtailment on the peak day, and as a cumulative function throughout the year.

Table 2: Constraint Overview by Year

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Yearly Constraint Events	0	0	87	241	300	334	354	354	354	354	354
Peak Day	5/24/2020	5/25/2021	5/25/2022	5/25/2023	5/24/2024	5/25/2025	5/25/2026	5/25/2027	5/24/2028	5/25/2029	5/25/2030
Peak Time	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM	1:15:00 PM
Peak Constraint Power / MW	0.0	0.0	6.6	17.6	28.7	38.7	48.7	48.7	48.7	48.7	48.7
Peak Constraint Energy / MWh	0.0	0.0	31.7	106.2	190.8	273.1	358.1	358.1	358.1	358.1	358.0
Entire Year Energy Curtailment/MWh	0.0	0.0	708.5	8119.8	22822.7	39364.4	57839.0	57789.7	57740.4	57691.2	57642.0

As no forecasts are applied, the PV queue stops after 2026 and no additional accrual in curtailment is identified. However, as stated earlier, it is more than likely that new DG will be proposed in addition to all known current applications.

It is also worth noting the fact that the number of event days per year encompasses almost every day of the calendar year by 2025, highlighting just how often the station would be overloaded due to reverse power flow. In this case, any curtailment effort would therefore require activation during almost every day of the year, as opposed to just in the summer months.

Assuming a total compensation of $24/kWh, which would have to either be reimbursed to the DG owners or taken as a loss on their side, the 2026 analysis would yield a total of $13.8M in

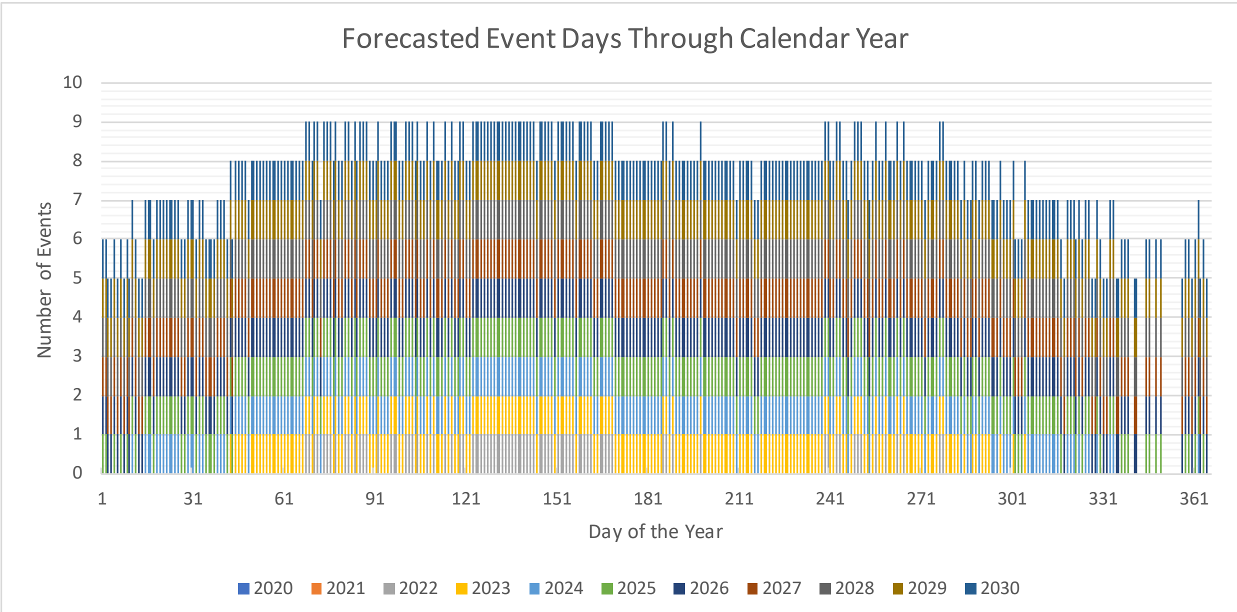
[7]Eversource assumes:

a) Load Growth is projected for peak load days and is linearly scaled to all other days and hours. As such, e.g. a load of 35 MW with a growth of 0.07 during peak, yields a growth of 0.035 when the station is reporting 17.5 MW.

b) All solar DG are modeled throughout the year using clear sky irradiance profiles provided through Clean Power Research's Solar Anywhere database for the specific location. The irradiance profiles are then converted to projected output in MW depending on the time of day and assuming optimal installation and orientation.

curtailed revenue loss, which equates to 57.5 GWh, or about 30% of the possible energy generation of the in-queue resources under ideal conditions. Figure 3 below shows the time periods during a year when the constraints occur.

Figure 3: Constraint Events by Forecast Year and Day



With a certain amount of DER adoption in a region, any curtailment approach will essentially be the norm, rather than the exception, making it exceedingly expensive to use such an option, and creating a direct conflict with the Commonwealth's climate goals.

Additionally, Eversource has been observing a growing trend in "overclocking" of solar installations (Panel rating > AC rating) resulting in higher utilization of solar DER. This overclocking makes solar DER output less susceptible to weather conditions because the larger panels, even at partial output during low irradiance conditions, can still produce power at the full inverter nameplate rating. A study conducted on Western Massachusetts Bulk Substations shows that at only 30% overclocking, (a value that is observed already today and that is showing an increasing trend), DER projects only rarely generated less than 70% of nameplate. Therefore, at these higher levels of overclocking, the resulting curtailment highlighted above would only further increase.

Furthermore, during years with inclement weather conditions, at these higher trending overclocking rates, AC output would still be at 70% of nameplate. The resulting curtailment under these circumstances would still equal about 20% of the annual production given the flatter PV output profiles due to overclocking. Our analysis indicates that the frequency and magnitude of overclocking (i.e. DC curtailment at inverters) is increasing yearly, resulting in more AC curtailment at grid that would be even higher than shown above, and would be prevalent even during inclement weather conditions – but for necessary transmission and distribution infrastructure upgrades.

Similarly, the Company does not agree that the AGO proposal to address DER system integration through export service options and pricing structures is workable. An essential element of the AGO proposal is that DER facilities would incur charges throughout the life of a system through an export tariff as opposed to a lump sum fee when interconnecting (AGO Comments at 10). In this way, interconnecting DER system owners would support the cost of EDC investment over the useful life of an asset instead of essentially making the investment themselves through cost reimbursement to the EDC. In the course of developing cost allocation recommendations filed with the Department in D.P.U. 19-55 Eversource worked collaboratively with the other EDCs and ScottMadden, Inc. to evaluate a wide range of alternative approaches for recovery of costs related to interconnection of DERs. The Company considered approaches, such as the CAISO Wholesale Distribution Access Tariff, that similarly support EDC interconnection investment through recurring charges instead of through up-front reimbursement. Eversource did not, and does not now, recommend such approaches as alternatives to the Cost Causation Principal because they would not effectively address the current challenges associated with funding system upgrades to enable the continued expansion of DERs in Massachusetts. The prohibitive impact to DER project economics associated with escalating system modification costs is minimally impacted when a DER developer incurs an obligation to pay ongoing charges in lieu of providing upfront reimbursement for system upgrades. In addition, implementation of a tariff to fund system upgrades over time would add administrative complexity and may increase uncertainty for DER developers without necessarily addressing the fundamental barriers currently facing the DER market in Massachusetts.

It is also not apparent to the Company that the price signals the AGO seeks to provide through export tariff structures would be particularly instructive with respect to the actual costs associated with interconnecting DER facilities. The costs of enabling the interconnection of DER facilities are highly location-specific and can vary substantially across different portions of the distribution system. The Company can readily provide useful price signals that reflect these variations by appropriately allocating the incremental fixed cost of interconnection to DER facilities through a one-time fee, but creating export tariff structures that equally reflect such locational variation could be exceedingly complex and less likely to be effective. The Attorney General's suggestion is designed to allow interconnecting facilities to avoid charges or reduce costs by exporting less during certain hours. This, as claimed, rewards DER customers for reducing the potential for future system upgrades. However, such behavior does not reduce the fixed system investment that was needed as a result of the interconnection of the facility at hand. Thus, the temporal charge would offer a price signal that is not consistent with the costs triggered by the interconnecting facility.

V. COST RECOVERY

In its Straw Proposal, the Department outlined a cost recovery framework in which costs of system modifications would be initially funded by the distribution company with subsequent recovery through a Reconciling Charge offset by CIP fees (Straw Proposal at 6). Eversource generally supports the Department's cost recovery framework outlined within its Straw Proposal.

The Company offers the following comments in reply to certain issues raised by other stakeholders in this process. Most significantly, the AGO asserts that the proposed method of cost recovery will produce a "windfall" for EDCs because DER developers may contribute to the cost of system upgrades before such assets are fully depreciated (AGO Comments at 11). The Company respectfully disagrees that the Department's straw proposal will result in EDCs receiving "windfalls" that exceed the recovery of Company investment and a reasonable return. The straw proposal contemplates that CIP fees would reduce, or offset entirely, the costs borne by ratepayers at large (Straw Proposal at 6). Eversource anticipates such a reduction would be accomplished by continuing to treat funds collected from DER developers as an offset to a company's rate base for ratemaking purposes, just as they are today. The Straw Proposal will allow for a timing difference to occur between when a system upgrade is completed by an EDC and when a future DER developer provides reimbursement for a portion of the cost of a CIP that enables the interconnection of their facility. An EDC will commit funds from its long-term capital structure for an interim period in order to construct a CIP under the straw proposal and it is reasonable for a company to have the opportunity to earn a return on those funds until such time that offsetting reimbursement is provided by a DER developer. However, as more DER facilities contribute CIP fees to interconnect to a given portion of the electric power system an EDCs net investment will progressively be offset and the costs recovered from other customers commensurately reduced. The comments of IREC recognize that some level of system upgrade costs that have historically been fully funded by DER developers would funded by the EDC and reflected in rate base under the straw proposal, but suggests the treatment of such investment could be made more clear (IREC Comments at 8). Eversource will work with the Department, the AGO and other stakeholders to ensure EDC net investment is transparently and consistently accounted for under any proposal adopted by the Department.

The AGO also asserts that risk associated with EDC investment under the straw proposal is substantially lowered and recommends the ROE for EDC investment made to support DER integration under the Department's proposal be reduced or eliminated (AGO Comments at 11). The AGO characterizes the CIP fees proposed by the Department as accelerated cost recovery that reduce risk for EDCs compared to other categories of EDC investment supported by retail revenues. As noted previously, the Department's proposed CIP structure will result in the Company providing interim funding for capital investment that has historically been wholly funded by interconnecting DER developers. Eversource will provide such funding from the same sources of financing used to support all other investment in the distribution system. The Department regularly reviews and approves the costs of each EDCs capital sources in normal base rate case proceedings and those values remain appropriate to apply to investments made under the straw proposal that would be funded from the same financing sources. The Department has previously recognized these financing considerations when approving application of a consistent ROE for investment by EDCs in utility-owned solar facilities subject to recovery through a reconciling mechanism (D.P.U. 09-38) and they apply equally to EDC investment under the Department's proposal in this proceeding.

Lastly, several commenters suggested that the Department incorporate ratepayer protections into the cost recovery approach out of concern that EDCs will have incentive to overbuild system upgrades under the straw proposal or be discouraged from pursuing other strategies for optimizing electric power system operations. The AGO recommends the Department require performance metrics around CIP utilization (AGO Comments at 11). The DOER recommends the cost recovery approach focus on optimizing demand (DOER Comments at 25) and IREC also expresses a concern that there is a potential for the CIP planning process to overestimate the necessary capital upgrades (IREC Comments at 8).

The desire to design and manage the electric power system as cost-efficiently as possible for the benefit of customers is a goal shared by Eversource. The Company expects that the identification of system upgrades through a robust planning process that includes stakeholder engagement will lend transparency and provide confidence in the resulting investments made by EDCs to enable DER growth in the Commonwealth. The Straw Proposal also suggests that all projects would need to obtain Department pre-approval for cost recovery before commencing. Eversource will work with the Department and stakeholders to standardize reporting of information that will support transparency and continuous improvement of DER-related planning and processes. However, given the controls that are already contemplated within the Straw Proposal, the Company views the application of performance metrics to cost recovery to be unnecessary and duplicative to other protections already built into the program design as contemplated.

In addition to establishing an appropriate framework for allocation of transmission upgrade costs as discussed previously, the Department will also need to provide a suitable method for recovery of EDC investment in transmission upgrades. In its recommendations submitted in D.P.U. 19-55, Eversource advised that recovery of transmission infrastructure modifications will need to be provided for differently from distribution investments and that there may be variation in the recovery mechanism across the EDCs. In the case of Eversource, it was indicated it may be feasible for the distribution company to provide reimbursement for transmission system upgrade costs, but recovery of such investment cost through retail distribution rates would require the establishment of a regulatory asset recovered over an appropriate amortization period. The Company will continue to consider methods for recovery of transmission upgrade costs as the Department works to finalize an alternative to the Cost Causation Principal and the specific transmission upgrades are identified.

VI. IMPLEMENTING ALTERNATIVE COST CAUSATION POLICY

As the Company indicated earlier in these comments, application of the current Cost Causation Policy is likely to emerge as a near-term barrier to the continued growth of DER in the Commonwealth. Eversource encourages the Department to work expeditiously with stakeholders in this proceeding to appropriately refine the current straw proposal into a framework that may be implemented to advance Massachusetts' clean energy and climate goals.

Implementation of an alternative Cost Causation Principal will require: (1) modifications to the EDC interconnection tariffs; (2) a detailed mechanisms for the recovery of pre-approved distribution and transmission system upgrade costs through a combination of project fees, reconciling charges and other recovery mechanisms identified by the Department. The Company looks forward to advancing implementation of an effective alternative Cost Causation Principle by addressing these requirements as well as through launch of a recommended system planning process supported by stakeholder engagement.

VII. CONCLUSION

Eversource appreciates the opportunity to provide these reply comments, to offer recommendations for the Department's consideration, and looks forward to fully participating in the Department's ongoing deliberations in this proceeding.

Respectfully Submitted,

NSTAR ELECTRIC COMPANY
d/b/a EVERSOURCE ENERGY

John K. Habib

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John K. Habib, Esq.
Matthew Stern, Esq.
Keegan Werlin LLP
99 High Street, 29th Fl.
Boston, MA 02110
(617) 951-1400