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

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

NSTAR Electric Company d/b/a Eversource Energy ("Eversource" or the "Company"), pursuant to the Vote and Order Opening Investigation issued by the Department of Public Utilities (the "Department") on October 22, 2020, in the above-captioned proceeding (the "Order"), hereby submits the following initial comments in response to the Department's Straw Proposal, which was set forth in Attachment A of the Order (the "Straw Proposal").

I. INTRODUCTION

The Department's Order opened an investigation into two issues for the Massachusetts electric distribution companies, which are Eversource, Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid ("National Grid"), and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") (individually, "Distribution Company" and collectively, "Distribution Companies"). The issues under investigation are: (1) distributed energy resource planning; and (2) the associated assignment and recovery of costs related to the distributed generation ("DG") process and infrastructure modifications needed to interconnect DG to a Distribution Company's electric power system ("EPS"). Order at 1. The Department's investigation is a continuation of issues considered in Distributed Generation Interconnection, D.P.U. 19-55, regarding the interconnection of DG pursuant to the Standards for Interconnection of Distributed Generation tariff ("DG Interconnection Tariff"). The Department's investigation in D.P.U. 19-55 included a request for comments on alternative cost allocation proposals for the interconnection of DG facilities. Order at 3; D.P.U. 19-55, Hearing Officer Procedural Memorandum at 3-4 (December 26, 2019).[1]

In its Straw Proposal, the Department proposes a new distributed energy resource planning process that is intended to identify optimal solutions for the interconnection of DG facilities under a long-term planning perspective. Order at 2. The Straw Proposal also requests comment on the methods for assignment and recovery of costs associated with the DG interconnection process and system modifications needed for interconnection. Order at 2.

Eversource strongly supports the Department's initiative to open this investigation and provide a thorough and well-conceived Straw Proposal as the starting point. In prior comments in D.P.U. 19-55 on the subject of cost allocation, Eversource recommended that the Department and stakeholders consider Massachusetts DG-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. 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 DG resources is an important, but not exclusive, goal that will continue to impact the electric power system into the future. Many aspects of the Straw Proposal will be effective to enable the development of an electric power system that

[1] Proposals for alternative cost allocation methods were submitted on February 28, 2020 in D.P.U. 19-55 from the following entities: Eversource; National Grid; the Massachusetts Office of the Attorney General ("AGO" or the "Attorney General"); the Northeast Clean Energy Council ("NECEC"); and Pope Energy.

is more efficient, lower cost than other alternative frameworks and of greater value to furthering state policy goals over the long-term.

II. RESPONSE TO DEPARTMENT'S STRAW PROPOSAL

A. Distributed Energy Resource Planning Requirements.

The Straw Proposal would require the Distribution Companies to produce a system planning analysis for infrastructure investment in consideration of clean energy and climate policy objectives, incorporation of DG investments, and development of associated planning criteria (Straw Proposal at 4). The Straw Proposal would require the Distribution Companies to conduct, on an annual basis, a rolling ten-year assessment of the EPS to identify: (1) a baseline of system upgrades to accommodate forecast load growth and DG interconnection; and (2) parallel upgrades that may be installed or expanded as a cost-effective solution to enable interconnection of capacity beyond currently proposed DG (Straw Proposal at 4-5). The Department proposes to establish DG-related planning criteria with stakeholder input (id. at 5).

Eversource supports the establishment of a stakeholder process to develop regional DG forecasting assumptions that would be incorporated into the Distribution Company's overall system planning analyses. This analysis will support optimal system planning consistent with applicable state policy goals, as well as appropriate allocation of system modification costs. Within these comments, the Company has sought to further describe how a stakeholder process to establish assumptions on DG forecasting will contribute to the development of a more transparent and understandable Distribution Company system planning analysis, and how that process might be structured and applied. The establishment of a stakeholder process to solicit input on the development and penetration of DG is a critical step forward.

At the same time, Eversource supports the fact that the Department's Straw Proposal acknowledges that the Company's traditional distribution and transmission system planning process is designed to support the Company's public service obligation to provide safe and reliable electric service. See, e.g., D.T.E. 98-84, at 10. The Company's traditional system-planning analysis to develop annual and long-term plans for load customers necessarily involves a holistic view of engineering needs across the distribution system, focused on the goal of providing safe and reliable service. The Department's Straw Proposal recognizes that the incorporation of broad, policy-related assumptions to the traditional system-planning process would introduce assumptions that do not necessarily correlate to the Company's obligation to provide safe and reliable service to customers.

Therefore, it is important to clarify that the Company does not support extending the stakeholder process to apply to the development or review of system planning criteria. Planning criteria rest on a series of standards, engineering parameters and other delineations that are critical to the safe and reliable operation of the distribution system for the benefit of customers that support and depend on that system. This distinction is critical to Eversource, as it remains the sole responsibility of the Distribution Company to provide safe and reliable electric service to its customers under the Department's purview. As described below, at the conclusion of these comments, Eversource recommends that the Stakeholder Input Process would be an appropriate and useful venue to allow the Company to obtain data and information on public-policy related inputs to the load forecasting process in areas such as DG, electric vehicles and electrification; and to consider alternative solutions for areas of need and opportunity arising from the Company's planning process. The Department should define this scope and set a timeline for this process with prescribed intervals for input and action to enable the annual filing with the Department.

The Straw Proposal identifies the following solutions to address potential system needs to serve DG customers: (1) implementation of technologies for voltage control on the EPS; (2) distribution bulk transformer addition or replacement; and (3) construction of new bulk stations. Eversource addresses the individual questions raised by the Department in the Straw Proposal, below.

Question 1: Should any of the identified solutions not be included on this list; should any additional solutions be included?

Eversource agrees with the appropriateness for inclusion of each solution identified by the Department (i.e., Technologies for Voltage Control, addition or replacement of Distribution Bulk Transformers, and new bulk distribution substations). In addition to these solutions, Eversource proposes to include the following additional solutions to address potential system needs:

1. *Distribution Feeder Upgrade or Addition* – Based on the distributed energy resource ("DER") impact, segments of the connecting distribution feeder might need to be upgraded to a larger conductor. In some cases, a new dedicated feeder (with associated station switchgear) may need to be constructed for the DERs.

2. *Radial Transmission Line Addition or Replacement* – Depending on the configuration of the system, some distribution bulk substations might require an additional transmission line in order to connect or upgrade a distribution bulk transformer consistent with Eversource planning criteria. This is especially true for single-transformer substations.

3. *Substation Switchgear Addition or Replacement* – often the addition or replacement of distribution bulk transformers requires the installation of associated distribution switchgear.

4. *Relay protection modifications or upgrades required to accommodate DER interconnection.* This includes: (1) building infrastructure to provide communication medium, such as fiber, that will support the supervisory control and data acquisition ("SCADA") devices where no radio or cellular signal is available; (2) proactively building stations with the capability of installing master direct transfer trip ("DTT") equipment at the substation for safety and reliability as more DER gets interconnected on the system; and (3) having DER customers activate and operate their Self Protection Over-Voltage ("SPOV") relay at appropriate levels so that as new DERs are connected to the system, the existing DERs would help mitigate potential transient over voltages ("TOV") on the system by varying their SPOV set points - which will not have any impact on their ISA or to their output.

Question 2: Should transmission studies and costs be included in proactive system planning related to interconnection?

Yes. Distribution and Transmission upgrades are related. Distribution upgrades to enable higher penetration of DER at bulk stations will inherently drive higher DER injection out of these stations, which in turn would result in higher flows on transmission lines. This impact could result in transmission constraints and the associated need to upgrade the transmission network. Understanding those transmission impacts will be key in identifying suitable transmission and distribution infrastructure upgrades needed to enable a high quantity of DER.

Question 3: Should the distribution system assessment identify projects that provide broader benefits beyond enabling incremental DG capacity?

Yes. A high-penetration DER future requires distribution companies to develop a comprehensive, holistic approach to system planning considering the integrated impacts of both load growth (including electric vehicle ("EV") adoption, energy efficiency, demand response, sector conversion, etc.), as well as DER adoption, rather than looking at these two dynamics as separate and independent activities. Therefore, any assessment of long-term system planning needs should identify upgrades that provide a broader benefit and can accommodate various types of load growth, as well as high penetration of DER. Not doing so may result in upgrades constructed that are either sized inadequately or would need to be upgraded prematurely.

System needs are identified and evaluated as part of Eversource's Distribution System Planning process on an as-needed and annual basis. During the distribution planning process, Eversource's System Planning develops a list of planned capital projects to meet identified system needs that are due to both forecasted load growth and projected DER connections. In parallel and on an ongoing basis, Eversource Distribution Engineering also develops a list of planned upgrades to distribution feeders to improve system reliability and resiliency, to ensure capacity, and to maintain voltage regulation.

Naturally there are synergies and overlaps in the upgrades and activities undertaken to integrate DER safely and reliably and the planning activities to accommodate new load types and provide reliable, resilient service to customers. For example, a distribution feeder that might need to be upgraded to prevent excessive voltage fluctuation due to DER penetration might also be reinforced cost-effectively with tree wire, spacer cable or aerial cable and upgraded poles to provide added reliability and resiliency to load customers. So, while the upgrade need was triggered because of DER penetration, the upgrade itself increases reliability and resiliency for a broader segment of customers. A bulk distribution substation transformer that might need to be upgraded to a larger size due to transient overvoltage ("TOV") impacts from in-queue DER would also concurrently better facilitate transfers between connected stations during N-1 contingency events, improving overall reliability for all distribution customers served by the stations. Integrated system planning drives the most optimal infrastructure solution set that yields value to not just DER enablement but, simultaneously, much broader benefits for many more customers.

To enable this integrated planning approach, Eversource is developing a probabilistic scenario-based DER adoption rate and load forecast methodology to evaluate the system's performance and assess the need for substation capacity upgrades over the ten-year planning horizon. Using a Scenario Planning approach, Eversource seeks to build on scenarios starting with the base need to reasonably forecast DER and load growth, but then build on that base scenario by also projecting EV growth or gas to electric sector conversion. Running multiple scenarios provides a system planner with the full scope of system needs to inform sizing of infrastructure upgrades appropriately.

Distribution System Planning would start by developing regional planning models to perform capacity, reliability, and power quality studies for bulk distribution substations, including ten-year substation capacity plans and DER impact studies on feeders and substations. The studies would be initiated for the purpose of:

- Investigating deficiencies in the performance of the electric supply system and to identify potential plans for system reinforcements or mitigating measures to address thermal capacity, voltage regulation, reliability, and operating flexibility issues;

- Investigating pre-existing power quality events resulting from DER penetration, affecting the distribution substation. These include TOV, 3VO assessment, DER impact on voltage regulating equipment, rapid voltage change, and voltage flicker; and
- Assess system performance to ensure that distribution substation designs meet or exceed Eversource's Distribution Planning Criteria.

The Company's Distribution System Planning Guide describes load model development and DER forecasting, a common planning model and study methodology for both distribution and DER planning, and comprehensive solution development to address system needs. This approach will increase efficiencies and provide the least cost option through better coordination of capital projects.

Question 3.1 If so, what benefits should be considered?

As described above, the comprehensive distribution system assessment envisioned by Eversource will identify projects that not only address system needs for integrating DER, but also simultaneously address system needs for providing superior service to Eversource's load customers (including new and changing load types such as EV and sector conversion), by improving capacity, reliability, resiliency, operational flexibility, voltage and power quality on the system.

More specifically, Eversource considers the benefits highlighted below to be some of the most essential due to projects identified to enable incremental DG capacity.

1. *Reliability, Resiliency and Operational Flexibility Benefits*: Includes any improvements to the system that might improve reliability and reduce customer outages or improve restoration times. Examples could include upgrading single-ended stations to two transformers rather than replacing the existing unit with a

single larger transformer. The incremental cost increases are justified by the enhanced reliability, resiliency and operational flexibility benefits for all customers concurrently derived from the investment through: (1) reduced reliance on neighboring station ties; and (2) increased ability to back up neighboring substations. This is discussed further in the response to Question 3.2 below.

2. *Modernization Benefits*: Most prevalent if the station impacted is in the upper quartile of the utility's asset age distribution, in extreme cases, equipment can be old enough to pose significant challenges when acquiring replacement hardware or conducting standard service and maintenance. Here, the marginal cost increase to replace a larger portion of a station and upgrade to the state-of-the-art equipment helps standardize utility operations, improves reliability, and reduces O&M expenses.

Question 3.2 How should benefits be quantified?

For reliability and operational flexibility benefits, Eversource recommends a quantification methodology that uses a comprehensive capacity allocation structure that simultaneously accounts for Reliability and Operational benefits (future load growth, and system operational requirements) in addition to Enabled DER Reserve benefits (in-queue DER and future forecasted DER). The reliability and operational benefits provided to the system as a concurrent benefit of DER-related upgrades can be quantified (as a proxy) by the available or enabled capacity within a distribution system. This quantification includes:

- <u>Operational Reserve</u> – capacity identified for enabling reliability, operational flexibility, and future small DER, which benefits utility customers at large, including DER facilities subject to the simplified process. It should be noted that

Operational Reserve is a benefit that is synonymous with DER enablement, not an add-on or optional reserve margin.

- *Enabled DER Reserve* – mostly benefiting DER facilities subject to the Expedited and Standard interconnection Process. This reserve is allocated by substation and DER Group.

Figure 1, below, summarizes the proposed capacity allocation structure and the relationship between the various components:

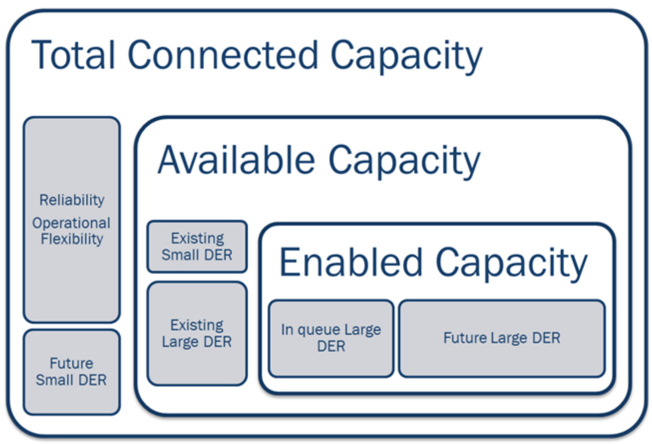

Figure 1: Components of Proposed Cost Allocation Structure

Existing DER is defined as the sum of the nameplate capacity (in MW) of all large and small scale DER currently connected to each substation. Small Scale DER is defined as any installation with an AC nameplate capacity of 200 kW or less, and large scale DER are installations greater than 200 kW AC nameplate capacity. Similarly, Future Large DER could be calculated by adding the AC nameplate capacities of all large installations with "in-queue" status.

Existing Minimum Load can be calculated by using historic meter readings at each substation and removing the contribution of existing DER to create a true, or gross load profile. Thereafter, the minimum load condition is identified in combination with the maximum possible DER output scenario at the time of minimum load, representing the worst-case condition the system can be faced with (e.g., a low load condition during midnight hours is not relevant for DER Group study).

Future Small DER can be forecasted by a probabilistic model that uses past historical adoption rate as well as the distribution of sizes per substation as inputs. Figure 2, below, shows a typical result of this analysis with the respective statistical spread by substation. A conservative approach can be used by selecting the upper quartile results, but if trends over the years show a slight reduction in adoption propensity (reflecting possible saturation limits) the median result can be used.

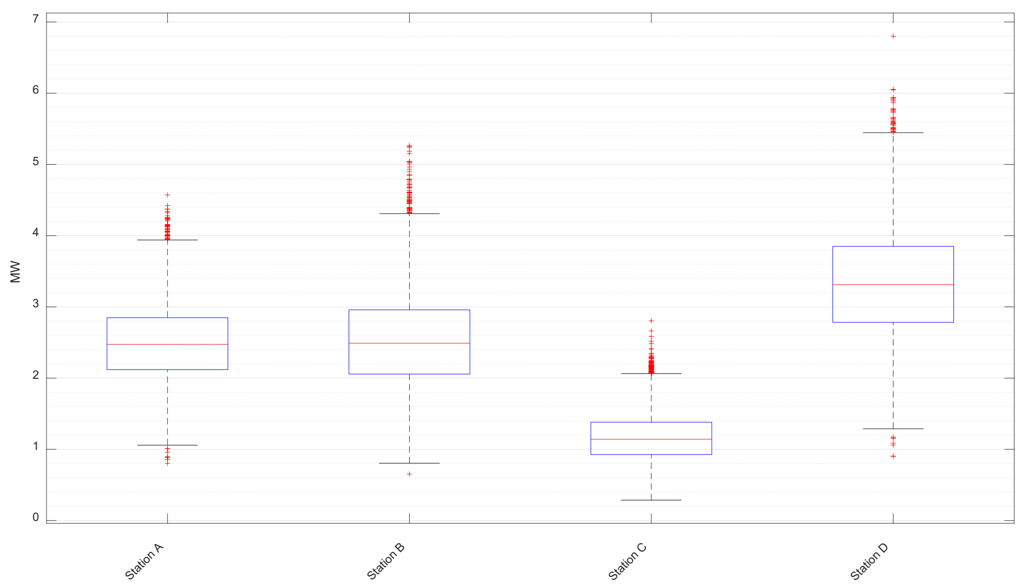

Figure 2: Typical Probabilistic Forecast Model Result for Four Substation Group

Using a median value for Substation C and a conservative value for Substations A, B, and D, Table 1, below, shows results for a DER Group study case consisting of four substations. Each substation has several MW of existing DER capacity and projected small DER growth and in-queue large DER.

Table 1: DER Group Study Results for a Four Substation Group

Station Name	Existing DER + Minimum Load (MW)	Future Small DER (MW)	Large DER in queue (MW)
Substation A	4	3	14
Substation B	5	3	22
Substation C	4	2	32
Substation D	4	4	33

Figure 3, below, represents the same 4 substation group if all in queue DER is connected, but no comprehensive reinforcements are completed. Note that the system will be saturated even under normal (N-0) system conditions.

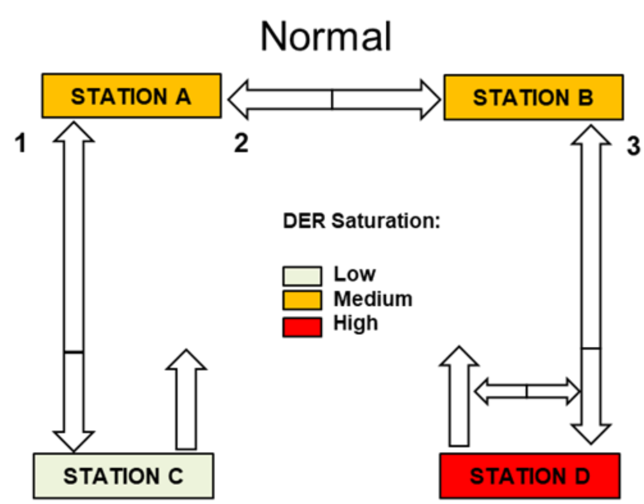

Figure 3: Four Substation Group with In-Queue DER and No System Upgrades

<u>Enabled Capacity</u> is defined as the available system capacity assuming all existing DERs are connected to the system after comprehensive system reinforcements are completed. This value is helpful in determining the remaining system capacity for future large DER connections after all in-queue DERs are connected to the system (refer to Formula below).

$$\boldsymbol{Enabled\ Capacity = \ Future\ Proposed\ Firm\ Capacity - (Sum\ of\ Existing\ DER + Sum\ of\ Future\ Small\ DER) + Sum\ of\ Minimum\ Load}$$

Firm Capacity is defined as the available substation capacity during the largest first contingency which accounts for capacity needed for reliability, operational flexibility, and emergency conditions. Therefore, the Firm Capacity is the available capacity after the capacity for reliability and operational flexibility allocation is accounted for. Using the same 4 substation DER Group Study case as above, the enabled capacity results are shown in Table 2, below.

Table 2: Enabled Capacity Results for Four Substation DER Group

Stations	Existing DER + Minimum Load (MW)	Future Small DER Reserve (MW)	Operational Reserve (MW)	Large DER in queue (MW)	Additional Future Large DER Reserve (MW)
Substation A	4	3	2	14	13
Substation B	5	3	63	22	34
Substation C	4	2	63	32	25
Substation D	4	4	63	33	22
Total			**191**	**101**	**94**

The 191 MW of capacity allocated for reliability and operational flexibility can be quantified as a benefit to the system in addition to the 195 MW of enabled DER capacity (101 MW in queue large DER and 94 MW of Future Large DER).

Although the full effects of operational conditions are determined after completion of a detailed load flow and transient analysis, such as those completed as part of a DER group study, a simplified review for the purpose of this high-level exercise, can be completed to quantify the benefits provided by the Operational Reserve. For example, using the same four-substation group, the effects of system reconfiguration following a critical first contingency operation scenario is shown below. In Figure 4, below, the Future Small and in queue large DER are incorporated into the existing system and the potential effects of first contingency scenarios are reflected in terms of saturation levels.

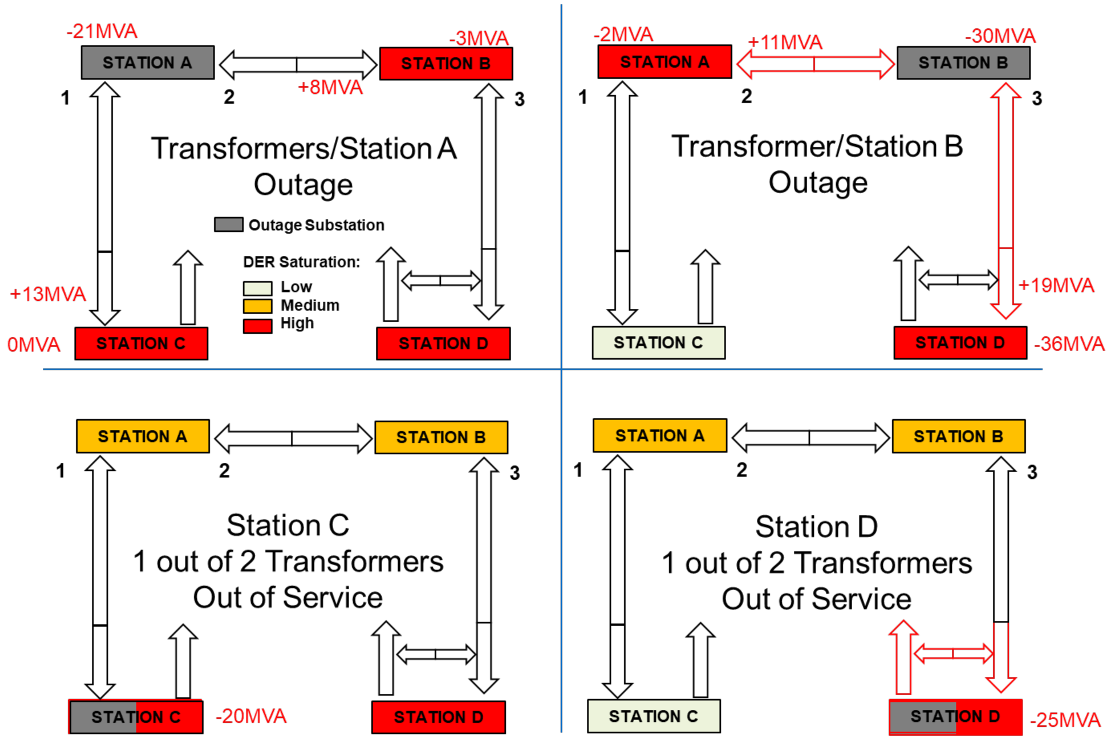

Figure 4: Contingency Scenarios for Four Substation Group with In-Queue DER and No System Upgrades

As an explanatory example, during an outage condition at Substation A, the first contingency operation is to transfer 100% of the system load and DER to nearby substations: approximately 37% (8 MVA) to Substation B and 63% (13 MVA) to Substation C. As a result of this post-event transfer, Substation B changes from medium to high saturation (-3 MVA) and the spare capacity at Substation C is reduced from 13 MVA to 0 MVA.

In areas of medium to high DER penetration, the substations must be analyzed as a study group to find the most cost-effective solution that integrates new DER while maintaining the current level of reliability and operational flexibility of the EPS. In this scenario, the standard approach of analyzing individual substations used for areas of low DER penetration, can potentially increase cost, reduce reliability, and limit operational flexibility. For example, even if upgrades are completed at Substation B and C to reduce the negative effects of increased DER penetration at those stations, this could still result in saturation at Substation A and D by limiting the transfer capability between A-C, D-C, and B-C, including distribution tie lines between substations. A DER group study approach analyzes the group as a whole to both determine the most cost-effective solution for all stations in the group, and simultaneously enable the capacity needed to maintain safe, reliable operation of the EPS.

The “as is” condition that results from having a system at medium saturation levels limits the flexibility of operators during normal and emergency conditions. Moreover, the condition also limits the ability of planners and engineers to propose system design changes that will improve the performance of the EPS and enhance service to existing utility customers. Utilities faced with significant DER growth, without the ability to address these types of conditions, could experience reliability deficiencies in the near-term when low DER saturated areas progress to medium or high saturation and are left unaddressed. DERs would experience long duration outages during any scheduled work at these stations as well as under forced (unplanned) outage scenarios.

The same system is analyzed in Figure 5, below, with proposed DER group study reinforcements and an assumption that 191 MW of Operational Reserve is enabled for reliability and operational flexibility.

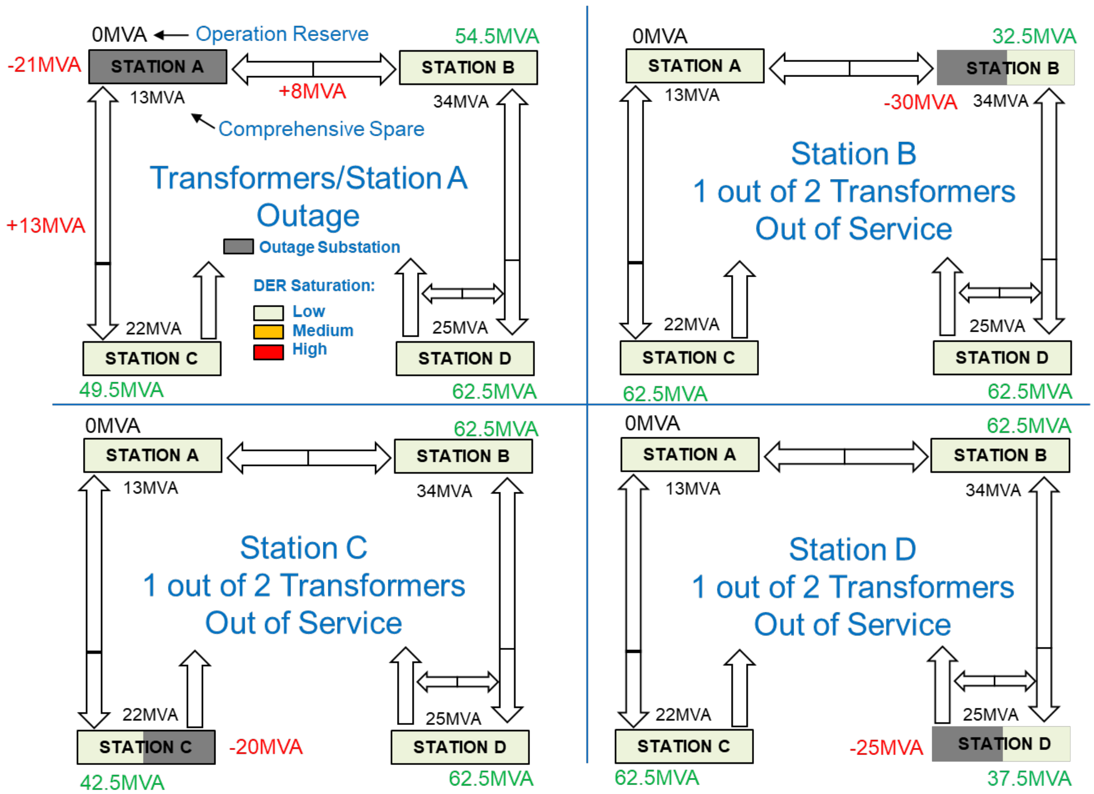

Figure 5: Contingency Scenarios for Four Substation Group with In-Queue DER and System Upgrades

The scenarios in Figure 5, above, also assume that 101 MW of in-queue large DER are already incorporated and that 94 MW of capacity for future large DER is available. By identifying for Existing DER, Enabled DER Reserve and Operational Reserve, this system provides a higher level of reliability and operational flexibility to all customers by reducing system saturation under all possible first contingency outage conditions.

Question 3.3 What is the appropriate method for cost assignment and recovery?

Eversource recommends that the method of cost assignment and recovery reflect the full scope of contributions that system modifications provide to the electric power systems and the users of the system. The Company recommends that the Department specifically differentiate Common System Modifications from other Capital Investment Projects, as each are defined in the Straw Proposal.

In Eversource's assessment, capacity upgrades at the bulk distribution substations needed to maintain the reliability and operational flexibility of the overall distribution system represents Common System Modifications that provide benefit to all users of the electric power system, not just interconnecting distributed generation customers. As a result, Eversource recommends that costs of Common System Modifications be recovered from all customers who benefit from use of the electric power system through the Reconciling Charge included in the Straw Proposal.

The cost of capacity reserved for interconnection of distributed generation facilities using the standard and expedited interconnection process remains appropriately funded by those facilities that benefit from the reserved portion of upgraded system capability. Eversource recommends that the Enabled DER Reserve represent Capital Investment Projects described in the straw proposal and be substantially funded through Capital Investment Project Fees also included in the straw proposal. Because "Enabled DER Reserve" is allocated at the substation level, it is possible to assess which interconnecting facilities are direct beneficiaries of this reserved capacity. Therefore, this capacity will be assessed by the Distribution Company to an interconnecting customer under the Expedited and Standard Process.

Eversource recommends deriving Enabled DER Reserve at each station, aggregated up to the Group Study Area, to inform total MWs enabled and a single $/kW charge to be recovered from all DERs connecting to applicable stations for each Group Study Area. To be specific, Eversource recommends calculating a MW enabled at each station but a Capital Investment Project fee rolled up to the Group Study Area – because the upgrades would be common for the group that all DER customers connecting up to those stations would benefit from.

Eversource stresses that these specific recommendations pertain *only to the allocation of bulk substation upgrades*. The costs of other projects on the distribution system, such as feeder upgrades likely warrant another method of cost assignment and recovery discussed separately in these comments.

In relation to cost recovery, the Department should establish an annual process whereby the electric companies present a plan to the Department that would delineate the projects that need to be undertaken to accommodate DR penetration. In this filing, each company would present the list of potential projects; the estimated cost range and the proportion of costs that would be assigned to the developer versus the system. In this proceeding, the Department would review and approve the projects allowed for the program and the allocation of costs between the electric company's customers and the developers. The actual project costs would then be subject to a review for prudence (i.e., cost management and implementation) at a later date, once the project is complete. The final cost allowed by the Department would then be split between the Company's customers and the developers, but the split assigned in the initial phase would not be revisited.

Question 4: Should there be a cap on the dollar-per-kW billed to each DG facility that benefits from a Capital Investment Project?

No, the costs of system modifications reserved to support the interconnection of distributed generation facilities, or a group of distributed generation facilities, should be fully and consistently allocated to those facilities without being limited by a cap. The Company expects that implementation of a cost allocation structure consistent with the straw proposal will lead to broader sharing of system modification costs by interconnecting distributed generation facilities and other customers, but the allocation of costs should still be based upon reasonable cost causation principals and not constrained by an arbitrary cap. The Company agrees that it would be appropriate for the costs of specific Capital Investment Projects that enable the interconnection of a group of distributed generation facilities to be consistently allocated to both current and future facilities through a fixed dollar-per-kW amount. However, the fixed dollar-per-kW amount should be specific to the Capital Investment Project(s) and the associated interconnecting facilities for each substation and/or group as previously discussed. It should not be considered a cap.

Further, after the proposed upgrades necessary to interconnect DERs in a Group Study area are planned and constructed and future DERs enabled is fully subscribed, to the extent additional DER development continues in that area, necessitating reconstruction or additional construction of much larger upgrades (such as a new station), the projected Capital Investment Project costs would be projected to be much higher – with no associated incremental Common System modification benefit. Not having a cap at that level of saturation provides the necessary and appropriate pricing signals for prudent DER development interconnection costs in that area. Therefore, Eversource does not recommend a cap for Capital Investment Projects.

Information Request 1: Please propose an optimal format for the 10-year distribution assessment. Including all substantive information points that should be contained in the assessment. Please include a proposal on the frequency with which such assessment should be conducted.

Response: Please refer to Attachment Eversource IR1.

Information Request 2: Please indicate the length of time required to update hosting capacity maps to reflect additional capacity built into the system after planned projects have been approved by the Department.

Response: Please refer to Attachment Eversource IR2.

Information Request 3: For illustrative purposes, please provide an estimated annual cap on the Reconciling Fee for the last five calendar years based on the description above.

Response: Please refer to Attachment Eversource IR3, which was previously submitted by the Company in this docket on December 4, 2020.

B. Capital Investment Projects/Common System Modification Fees

The Department envisions that the distribution-system planning and assessment process will identify system infrastructure projects that might qualify for special ratemaking treatment with cost recovery through a Reconciling Charge, i.e., "Capital Investment Projects". The Straw Proposal defines a Capital Invest Project 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 DG… (Straw Proposal at 1).

Capital Investment Projects proposed by a Distribution Company would be eligible for consideration of cost recovery through a Reconciling Charge and Capital Investment Project 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.

In the Straw Proposal, the Department indicates that, while the Capital Investment Project Fee portion of the Straw Proposal coupled with existing cost allocation structures will be sufficient to address recovery of costs for interconnection of DG, the Department is willing to consider whether a Common System Modification 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).

As discussed previously with respect to the consideration of all benefits within the system planning process, the Company recommends that the Department specifically differentiate Common System Modifications from other Capital Investment Projects in both the criteria by which they are identified and how the costs of such modifications are allocated. The Company recommends a distribution planning process that will reserve system capacity for the interconnection of distributed generation facilities. The Company considers such upgrades to be consistent with the Straw Proposal description of Capital Investment Projects and recommends they be funded by Capital Investment Project Fees to the extent possible. The Company also proposes that system capacity be reserved to support reliability and operational flexibility of the electric power system, representing Common System Modifications appropriately funded by all customers who benefit from use of the electric power system through the Reconciling Charge included in the Straw Proposal.

1. Potential Additional Fees

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 (Straw Proposal at 9).

The Company does not expect that any fee structure will independently facilitate timely construction of distribution system upgrades. The timely construction of optimal electric power system solutions will likely be best advanced through a system planning process suggested by the straw proposal and further described by the Company in these comments. A recommended fee structure should appropriately align with the system planning process and the full range of benefits that system upgrades support.

(a) Simplified Projects

In addition, the Department indicated that a Common System Modification Fee could be a method to offset the costs of System Modifications triggered by facilities subject to the Simplified Process under the DG Interconnection Tariff, which have historically not been required to pay for System Modification costs except in rare instances (Straw Proposal at 10). With respect to Expedited and Standard Process Facilities, the Department indicated that Common System Modification Fees may be beneficial where "the cost to interconnect may become prohibitive for an individual Facility, or a group of Facilities, thereby stalling the deployment of DG across the Commonwealth" (id. at 11). The Department noted that there are various ways a Common System Modification Fee could be structured (id. at 11-12).

The Department's Straw Proposal requests, and the Company provides below, responses to the following questions concerning the potential implementation of Common System Modification Fees for Simplified Facilities.

Question 5: Is a Common System Modification Fee appropriate for Facilities using the simplified interconnection process? If so, provide a proposed method for establishing such a fee.

The Company recognizes that it may be appropriate for the Department to approve a unique fee structure for other types of modifications projects using the simplified interconnection process that allocates a consistent amount to such facilities in order to balance cost causation goals with administrative considerations for smaller distributed generation facilities. Such a fee structure may assess a consistent average or "common" fee to facilities using the simplified interconnection process but it should still only pertain to the costs of system modifications which specifically support the interconnection of distributed generation facilities that use the simplified process and do not address other system requirements or objectives.

The Company does not recommend that the costs of Common System Modifications i.e., the rate-based portion of the company's bulk station upgrades that support reliability and operational flexibility of the electric power system be assessed to facilities using either the simplified, expedited or standard interconnection process.

Question 6: What types of upgrades should be funded by a Common System Modification fee for Facilities using the simplified interconnection process?

Eversource recommends any fee structure applied to facilities using the simplified process should: (1) apply to a limited set of system modifications; and (2) exclude any costs of bulk system modifications. Reasonable system modifications to fund through a separate fee structure may include transformer upgrades or other service reconfigurations and upgrades periodically required for the interconnection of facilities using the simplified process.

Question 7: How would such a fee interact with the system planning process described in Section II of the Straw Proposal? Should fees collected from Facilities using the simplified interconnection process be used to offset the costs of Capital Investment Projects approved through the proposed distribution system planning process?

The Company recommends that the system planning process account for growth in Small DER resources that are likely to use the simplified interconnection process, but does not recommend a fee structure that collects the cost of bulk system upgrades from such projects. The

Company recommends that the system planning process seek operational flexibility consistent with expectations for more dynamic use of the electric power system that includes, but is not limited to, further expansion of onsite generation. As a result, Eversource recommends that the Operational Reserve associated with Common System Modifications be based, in part, on projected growth in small DERs and that costs of Common System Modification that contribute to an Operational Reserve that supports reliability and operational flexibility be funded by customers broadly rather than allocated to interconnecting distributed generation facilities, including those using the simplified process.

(b) Implementation for Expedited and Standard Facilities.

The Department's Straw Proposal also requests discussion of whether a minimum, fixed or maximum Common System Modification Fee is appropriate for Expedited and Standard Facilities (CITE). The Company's responses are provided in detail below.

Question 8: Are minimum, fixed or maximum Common System Modification Fees appropriate?

No, Eversource does not recommend that any fees be assessed to facilities for Common System Modifications reserved to support reliability and operational flexibility of the electric power system. Capital Investment Project Fees collected from interconnecting facilities should be based only on the cost of Capital Investment Projects substantially reserved to enable their interconnection, individually or as part of group, to the electric power system. These fees should fully reflect a proportional contribution of a facility for an upgrade that enables its interconnection and should not be based upon any minimum, fixed or maximum contribution. The efficient use of the electric power system will continue to be encouraged by providing the opportunity for facilities to lower interconnection costs by seeking out advantageous portions of the distribution system for interconnection. The Distribution Companies developed and maintain hosting capacity maps for this express purpose. The elimination of these price signals through the imposition of minimum, fixed or average fees would potentially inhibit constructive financial incentives

(c) Additional implementation issues

The Department's Straw Proposal requests discussion of several additional issues concerning Common System Modification Fees. The Company's responses are provided below.

Question 9: Should fees should be based on nameplate capacity, export capacity, or a weighted combination of the two?

The Company recommends that fees continue to be based on nameplate capacity. This will keep the allocation consistent with Section 3.4.1 of the Company's interconnection tariff, as approved in D.P.U. 17-164-A on October 15, 2020. Section 3.4.1(h) states in pertinent part:

> The Group Study shall be performed such that System Modifications, whether shared or individual, and associated costs shall be determined for the entire Group, along with allocated costs for each member of the Group. Cost allocations shall be assessed on the basis of the aggregated system design capacity for each applicant's Facility (in MW AC) for any Common System Modifications required. For purposes of Common System Modification cost allocations under this section only, and for no other purpose under the Interconnection Tariff, if an Interconnecting Customer proposes an inverter based generation Facility with an integrated energy storage system ("ESS"), and the Company, in its sole discretion, approves the Interconnecting Customer's export limiting scheme for the integrated Facility (i.e., inverter-based generation plus ESS) (if any) ("Maximum Export Capacity"), then the Common System Modification cost allocation for that Facility(ies) will be based on the aggregated system design capacity subject to the Maximum Export Capacity. The Interconnecting Customer must certify its Maximum Export Capacity and provide all necessary documentation for the Company's review prior to the commencement of the Group Study.

Basing the fees on export capacity keeps the fees consistent with the approach in Section 3.4.1 for group studies.

Question 10: How should the Department determine which upgrades would be covered by Common System Modification Fees collected?

Eversource proposes that Common System Modifications be limited to the bulk distribution substation level upgrades necessary to provide system reserve capacity for reliability and operational flexibility (Operational Reserve). The Company also recommends that recovery of Common System Modification costs through the Reconciling Charge is most appropriate, because associated upgrades broadly benefit the distribution system. Bulk distribution substation level upgrades that further enable the interconnection of current and future DER using the expedited and standard process are appropriately funded by Capital Investment Project fees and, as discussed previously, the Company would support a separate shared fee structure that recovers feeder level upgrade costs from projects using the simplified process.

Question 11: Would upgrades covered by Common System Modification Fees be subject to Department approval?

Yes, the Company recommends Department review and approval of proposed upgrades to be recovered through all fees and charges. The Company has suggested that Common System Modifications be substantially funded through the Reconciling Charge and Capital Investment Project costs be recovered through Capital Investment Project Fees. Development of upgrades covered by both mechanisms will be a substantial undertaking that will require regulatory support from the Department to protect the interests of customers, the Company, and other stakeholders throughout the deployment process. Anticipated upgrades will involve significant near-term expenditures that are in excess of distribution expenditures that would be incurred absent the growth of DER and implementation of the planning process contemplated in the Straw Proposal. The Company supports the Department's engagement to review and approve upgrade plans and associated charges and fees. Department review will provide transparency for all interests involved and will facilitate efforts to track and review ongoing costs associated with DER interconnection, while at the same time allowing the Company to obtain timely and adequate recovery of expenditures.

Moreover, Eversource recommends that the Department review and pre-authorize system upgrade plans, similar to how the Department currently reviews and approves the prudence of estimated costs associated with the Company's grid modernization investment plan and energy efficiency investment plans. As discussed above, the Department should establish an annual process whereby the electric companies present a plan to the Department that would delineate the projects that need to be undertaken to accommodate DR penetration. In this filing, each company would present the list of potential projects; the estimated cost range and the proportion of costs that would be assigned to the developer versus the system. In this proceeding, the Department would review and approve the projects allowed for the program and the allocation of costs between the electric company's customers and the developers. The actual project costs would then be subject to a review for prudence (i.e., cost management and implementation) at a later date, once the project is complete. The final cost allowed by the Department would then be split between the Company's customers and the developers, but the split assigned in the initial phase would not be revisited.

This sort of process will not foreclose the Department's further review of the prudence of a company's implementation and cost-management of pre-authorized investments upon completion of system upgrades. In addition, in the course of preauthorizing system upgrades and estimated costs, the Company recommends the Department also review and approve the structure of Capital Investment Project Fees to be assessed to interconnecting facilities.

The Company supports the transparency that its recommended review of system upgrades provides, but also recognizes that prolonging the finalization of project fees and initiation of constructing activity also presents challenges to development of DG facilities that may be dependent on the outcome of the Department's review. The Company proposes that the uncertainty and timelines for such a review could be expedited by establishing clear guidelines for the content of EDC filings and appropriately focusing the scope of the Department's review in such proceedings.

Information Request 4:

For each of the last ten years, provide estimates for the following:

1. **The minimum, maximum, median and average system modification cost for Facilities using the simplified interconnection process. Please also provide the total number and capacity of Facilities using the simplified interconnection process that have applied by year and the cumulative total system modification costs charged to Facilities in each year.**
2. **The minimum, maximum, median, and average system modification cost for Facilities using the expedited and standard interconnection processes. Please also provide the total number and capacity of Facilities using the expedited and standard interconnection process that have applied by year and the cumulative total system modification costs charged to Facilities in each year.**

Response: Please refer to Attachment Eversource IR4, previously provided by the Company in this docket on December 4, 2020.

Information Request 5:

To date, how much money have the Distribution Companies collected through the imposition of interconnection application fees, study costs, and interconnection related construction costs? Please organize this information by year going back to 2011 as well as by Facility type (i.e., Simplified, Expedited, Standard)?

Response: Please refer to Attachment Eversource IR5.

C. Proposals for Implementation in the Short Term.

1. Discussion of Attorney General's Power Control Limiting Program

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 Order, Att. B-1 (AGO cover letter) at 3. Under the Attorney General's Power Control Limiting program, a DG 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.

The Straw Proposal requests discussion of the effectiveness of the AGO's proposed Power Control Limiting Program, included as Attachment B-1 to the Department's Order.

Question 12: Does Eversource currently have the ability to implement the AGO's proposed program, and if not, what would be required to implement the program?

Eversource agrees that the AGO's proposed program to allow interconnecting DERs to statically limit their output to reduce their interconnection cost is rational and reasonable. By allowing the reduction of peak power capability, resource capacity that is rarely utilized (e.g., the upper 20 percent of a solar panel output curve) is removed from the interconnection equation and a cost benefit analysis can be conducted to show how much curtailment is feasible, before higher interconnection costs are applicable. Therefore, in essence the static curtailment approach is already being utilized by the developer community and Eversource.

Eversource already permits developers to statically limiting power at any DER installation site (not just solar), which is commonly done today by the site developer community. To ensure that such a static curtailment is actually performed, Eversource typically requires use of Directional Power Relays (ANSI Function 32), which have the capability to limit import/export to/from any DER facility to a static value.[2] The use of two relays in series allows the limiting of both power import and export. A typical application on Eversource's system is co-located storage plus solar where the storage system is designated to only charge from the solar plant. As such a 32-function relay would be installed to prohibit power consumption from the grid by the storage site, ensuring it is only ever charged from the solar installation. For limitation of solar only installations, the developers act on their own account, as highlighted next.

Developers utilize a concept known as "overclocking" solar installations. This is achieved by installation of solar panels with a rating in excess of the inverter rating. This concept is illustrated in Figure 6 below. With the understanding that it is not the inverter generating the power but the PV panels, developers opt to install larger panels than they have available inverter capacity. The result of overclocking the solar installation is that developers effectively use the inverters as permanent curtailment.

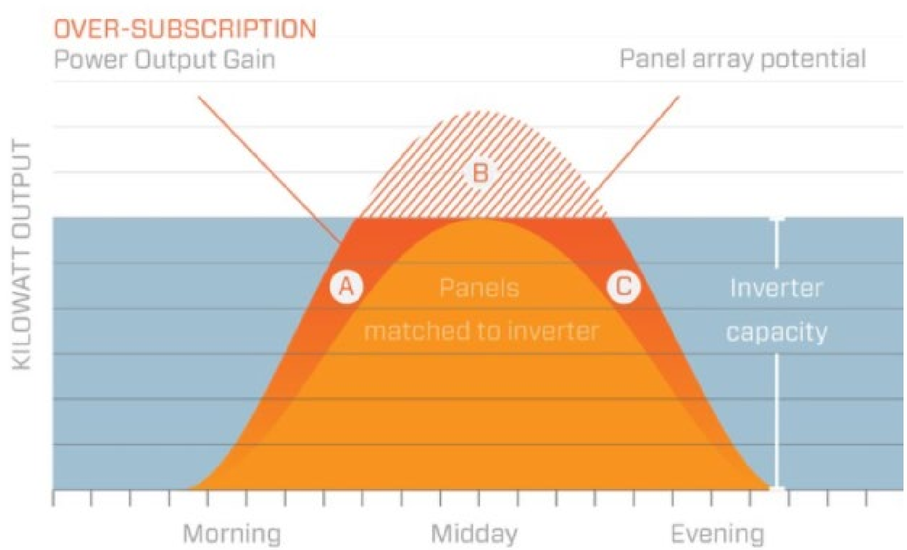

Figure 6: Schematic of Solar Output Profiles Inverter (AC) and Panel (DC) Ratings

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2 https://www.eversource.com/content/docs/default-source/builders-contractors/der-information-technical-requirements.pdf?sfvrsn=ab2bfc62_10

As noted below, this "over-clocking" approach has several directly observable consequences:

- Through the increased panel size, developers attain a higher utilization rate for inverter and interconnection capacity, as such can generate power relatively cheaper.
- Developers protect themselves against low sun time such as winter months (e.g., a 10 MW panel at 50 percent during wintertime produces 5 MW, which on a 7 MW inverter still represents greater than 70 percent utilization.

On the other hand, for Eversource, this has had some additional consequences in terms of how solar output impacts the distribution system:

- *Daily solar* curves reach maximum output much earlier in the day and remain at maximum output for most of their generation time as shown in Figure 7, below, which represents an anonymized real time of use generation data set for a day in July. What can be observed clearly, is that the panel holds peak output for about 4 hours. As a result, any curtailment to gain capacity would not (as commonly assumed) represent a curtailment of only a small peak, but impact a broad energy producing capacity.
- *Yearly solar* curves show us that EDCs can expecting peak solar output across their portfolio at almost any day of the year. Figure 7 shows the same PV plant's generation profile for the period of January through July 2020. As a result, utilities are faced with high DG output across the year, which can occur at any and all load conditions, resulting in not only a few days of curtailment need, but significant

amounts. For saturated stations, this all but guarantees that any form of curtailment would be reducing energy production almost every day.

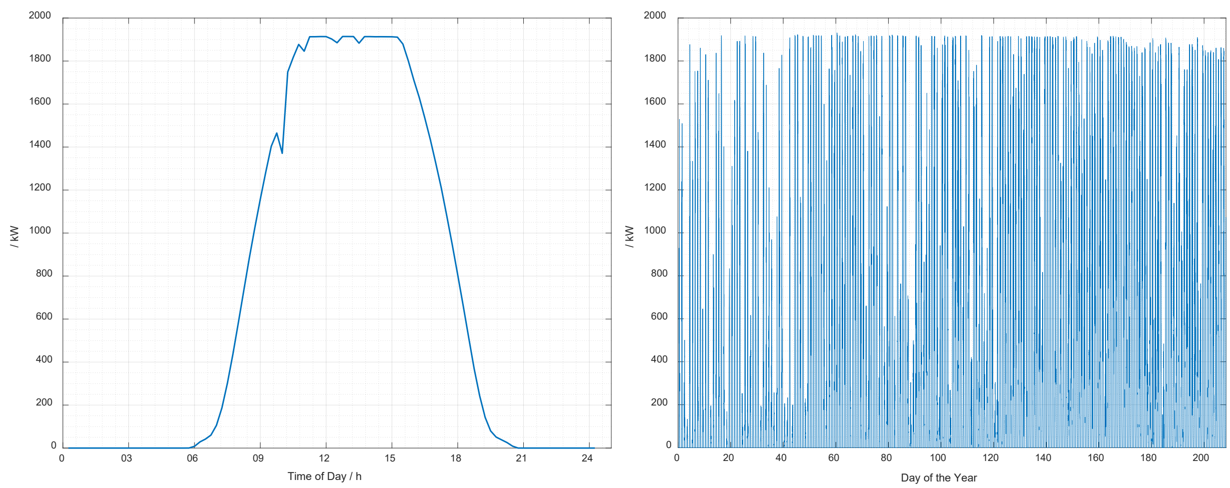

Figure 7:a) Daily curve of a real life overclocked solar installation and b) yearly curve of the same installation

Eversource has observed that almost all installations, large and small, in its territory already follow this practice, and that typical ratings for the panels (DC Rating) are 120% or more of the inverter rating (AC Rating). In some cases, an overclocking of more than 200 percent has been observed. As a result, it is important to note that any curtailment effort, especially static, *would not (as commonly assumed) only be limited one or two days a year, but rather potentially reduces generation capacity for all days of the year*. Due to the fact that developers have already taken steps to curtail their own panels through smaller inverters, and that the EDCs design their systems to the inverter capabilities, further curtailment comes at a steep price in terms of energy loss. For the above example, a curtailment of 10 percent of capacity would result in an annual loss of generation capacity greater than 5 percent, which is representative of other solar sites which overclock their installations. This is caused by a 10-percent capacity curtailment representing not a curtailment from 100 percent to 90 percent, but rather, in the case of this installation, from 75 percent to 65 percent. Any economical feasible curtailment has already been conducted by the developers themselves out of self-interest to maximize revenues under limited inverter ratings.

In summary, Eversource agrees with the AGO's approach, subject to the qualification that developers and the Distribution Companies have already taken steps, as outlined above, to make the implementation of additional power limiting applications more difficult. Eversource will continue to work with developers to inform them that a reduction of size through static power limiting is an option and deemed to be the more cost-effective, safe or reliable solution.

It should also be noted that the static curtailment (as well as the dynamic option discussed later) does not guarantee an avoidance or reduction of interconnection cost. Any curtailment program can only target capacity issues, or in rarer cases static voltage violations. Such curtailment programs cannot, however, help with Transient Over Voltages, Protection Limitations, or Islanding Issues that have been identified by Eversource as some of the most limiting constraints in SEMA.

For all of these reasons, Eversource also does not see a static curtailment program as a method to avoid saturated station upgrades or associated implications for cost allocation calculations in any way. Rather, the Company views such a program as a resizing of the interconnecting asset to optimize economics for the developer. Although Eversource can assist developers in avoiding certain costs, it does not increase hosting capacity on a circuit and any applicant breaching system capacity would still be required, curtailment or not, to pay for any applicable upgrades.

It is Eversource's understanding that the available capacity to be permanently curtailed has already been fully utilized as it stands today and that we see limited to no additional value as it relates to avoiding additional interconnection cost that can be generated through further curtailment. Accordingly, any capacity deficiencies currently identified by Eversource are, in fact, happening with a static curtailment already broadly in place.

Lastly, Eversource views that any significant amount of curtailment, especially static curtailment, is in direct conflict with the state's clean energy policy goals, as curtailed energy will be replaced by other sources. Efforts should therefore be focused on transporting and/or storing energy with DC coupled systems.

Question 13: Should eligibility for the program be for (a) new Interconnecting Customers or (b) new and existing Interconnecting Customers?

Existing customers have already completed an interconnection, paid their interconnection costs, and built a business case that allows them to operate. Any additional power limiting that would be applied after the fact would upset those financial calculations. As a result, these customers would have to be financially compensated through some mechanism to make up for lost revenue, if they are eligible.

For new customers, this is already an option, and any developer can do their own financial calculations to assess the feasibility of power limitation to avoid a larger interconnection bill.

Question 14: What equipment and software are necessary for implementation of the program and which equipment and software would be installed (a) at the Interconnecting Customer and (b) the Distribution Company?

The simplest solution for a permanent curtailment is either limitation of the inverter nameplate rating, which equates to overclocking the solar plants (described above in the response to Question 13), or installation of a power limiting directional relay (32-function relay). For an example of the Company's proposed solution in this regard, please refer to the Department's proposed, revised Section 4.3 (April 16, 2020) of the DG interconnection Tariff.[3]

Since the proposal calls for a static limitation, similar to the AGO's reference to the Minnesota Public Utilities Commission's DIP section 5.14.3, Eversource is well-equipped to implement these measures and, in fact, is already doing so where financial and technically feasible.

Question 15: Would any amendments or attachments to the ISA be necessary to implement the program?

Eversource does not view that any changes are needed to the current ISA under the assumption that existing customers will not be considered for additional static power limitations beyond what is already in place. If that is not the case, then post-ISA changes may be needed to make existing customers financially whole.

2. Discussion of Attorney General's Dynamic Curtailment Program.

The Attorney General also proposed dynamic curtailment as a means to control and manage power export to mitigate or avoid System Modification costs for medium and large DG Facilities. See Order, Att. B-1 (AGO Cover Letter), at 3. The Attorney General recommended that Massachusetts establish a dynamic curtailment program in which a developer proposing to interconnect to a congested circuit would agree to an estimated amount of export curtailment as an economic alternative to otherwise necessary system modification costs. Order, Att. B-1 (AGO Att.), at 17-18.

[3] Joint Distribution Company Comments Regarding Department Guidance on the Interconnection of Energy Storage Systems, April 28, 2020, Attachment A.

Question 16: Does Eversource currently have the ability to implement the AGO's proposed Dynamic Curtailment Program, and if not, explain what would be required to successfully implement the program?

Eversource supports the AGO's purpose and intent for the proposed Dynamic Curtailment Program. However, the Company anticipates technical, economic, and legal challenges that are inherent with such a program, as will be further detailed in response to Questions 17-19. Primarily, Eversource foresees challenges with the overall cost to benefit ratio of such a program, specifically if observed under the premise that to increase renewable energy in our energy mix, curtailment should not be the first choice.

As outlined above in Eversource's response to the AGO's Static Curtailment Program proposal, developers and Eversource already conduct static curtailment on a large scale, which has nonetheless resulted in significant capacity deficits.

Although it can be argued that a dynamic curtailment program can be more focused on the days of need compared to the static curtailment, Eversource has discussed above that due to the overclocking of PV installations, dynamic curtailment would need to actively manage the system hundreds of days a year in DG saturated areas such as in SEMA. Some European countries that have chosen curtailment initially are now forced to face the reality that curtailment cannot displace capacity when large scale renewable rollout is the objective, and are now initiating some of the largest capital projects in recent history to avoid such high levels of curtailment.[4,5] Meanwhile, renewable energy is being curtailed and millions of dollars are being paid in compensation.

With intermittent resources, such as solar or wind, physics dictate that there will be an increase in the installed generation capacity on the Company's system to a factor of five or more

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[4] https://www.greentechmedia.com/articles/read/germanys-stressed-grid-is-causing-trouble-across-europe

[5] https://www.greentechmedia.com/articles/read/as-germany-curtails-wind-and-solar-billion-euro-grid-projects-seek-to-bring

(which results in ISOs around the country providing low-capacity credits).[6] Consequently, any system operator will find themselves in a situation where more energy is currently being generated than can be locally consumed. Therefore, the objective in a clean energy future should first be to store, transport or export energy, not to curtail it.

Although dynamic curtailment in lieu of necessary baseline backbone infrastructure upgrades in heavily DER saturated stations is not feasible, Eversource agrees that there is value for such a solution as a very targeted approach for small to medium capacity deficits and as interim solutions until larger capital expansions can be completed. *Under the assumption of such a targeted application*, the Company fully supports the AGO's further investigation of the Dynamic Power Curtailment Program and any future potential pilots to further evaluate the concepts, understand the challenges and begin discussion and development of possible solutions.

Understanding the complexity, from a technology and legal standpoint, Eversource currently does not have the ability to implement the program as proposed by the AGO. Therefore, Eversource does not see a way to avoid immediate necessary infrastructure investments to ensure safe, reliably interconnection of DERs. At a high level, such a dynamic curtailment program would require the following:

(1) Ability to make real time DER dispatch decisions based on system power flow conditions, resulting from changes in intermitted generation and load.

(2) An intra-day time series power flow (<24h) specifically for resources such as storage or storage plus solar to ensure storage capacities are adequately accounted for.

[6] https://www.nrel.gov/docs/fy20osti/74823.pdf , slide 48

(3) A day-ahead time series power flow (24-48h) specifically for resources such as storage or storage plus solar to ensure storage capacities can adequately account for curtailment if participating in markets.

(4) An Optimal Power Flow calculation with all controllable assets for both the intra-day and day-ahead forecasts to determine the optimal system status which requires minimal customer curtailment while not endangering safe and reliable operations. Controllable assets can include but are not limited to:

a. Dynamic Curtailable Resources;

b. DER Resources on the same circuit such as utility scale BESS; and

c. Voltage control devices such as voltage regulators, capacitors, DVAR, STATCOM.

(5) Capability to send granular dispatch signals to DER and verify their compliance.

In essence, the proposed program would require a fully functional DERMS solution, and depending on the functional capabilities of the DERMS, it may also require upgrades to the DMS. Figure 8, below, shows a market cross-section of DERMS concepts. A dynamic curtailment program, as described by the Attorney General, would require, at a minimum, a DERMS as a Utility Grid EMS approach.

DERMS as Premise-Level EMS	DERMS as Aggregator & Fleet Manager	DERMS as Utility Grid EMS	DERMS as Wholesale Market VPP	DERMS as DER Billing, Smart Contracts & Settlement
• Premise load forecasting • Storage SOC monitoring • Local optimization of DER dispatch • Remote monitoring and control • DER forecasting	• DER aggregation • Profile management • Flexibility management • Autonomous dispatch • Load/supply following • NOC dispatch	• DER monitoring • DER direct control • DER constraint management • DER dispatch and scheduling • Integrated system planning • Aggregator-of-aggregators • Grid power flow • Optimal power flow (e.g. VVO) • **Distribution Automation** • Restoration & transfer capacity	• Local DER optimization using DSP-based pricing and signals • Individual and aggregated DER participation into wholesale markets • Local DER optimization using market-based pricing and signals	• Energy M & V • AMI integration • DER interface • Price discovery • Smart contracts • Potential application of blockchain technologies

Figure 8: Variations of DERMS Solutions in the Market

Eversource does not currently have a DERMS platform but has been investigating application of DERMS as part of its Grid Modernization initiative. Scoping and implementing a DERMS platform capable of dynamically integrating high DER penetration can be a very complicated, protracted process that and takes many years to specify, procure and implement. In the meantime, the DER queue will keep growing and Eversource will continue to be responsible for safe, reliable integration.

Question 17: Please identify equipment and software necessary for implementation of the program and which equipment and software would be installed (a) at the Interconnecting Customer and (b) at the Distribution Company.

The AGO's proposed Dynamic Curtailment Program would require several technological upgrades, both at Company and customer facilities. Interconnecting customers would be required to provide standardized communication interfaces and expose control functions of their inverters. To date, Eversource has had remote access only to the point of interconnection (Point of Common Coupling, PCC) for large DERs with the ability to disconnect. However, for an active curtailment program such as that proposed by the AGO, a course, binary control option would not be sufficient and could cause issues within the developer community. Therefore, a more fine, granular control is required, which requires direct control of the facilities' inverter functions. This also requires IEEE 1547-2018 listed Smart Inverters that have been verified to UL1741-SB to be able to perform the required commands**.**

The Distribution Company would need to make the majority of the investments in a DERMS enterprise system. These requirements mirror themselves in the solution specifications that the utilities located in the United Kingdom, as referenced by the AGO, have developed with Smarter Grid Solutions,[7] as well as those currently under development by EPRI,[8] or SEPA.[9] Such requirements and considerations include:

- *DERMS*, under the assumption that all capabilities are available within a DERMS, otherwise upgrades to the DMS with ADMS features would be required. See Question 17 for the EPRI and SEPA citations for details.

- *Hardware and other requirements* for such a program are difficult to determine without digging into specific system details and can vary widely. In most cases, however, upgrades to sensor telemetry along the feeders and stations, remote control capabilities, back up controls to isolate non-responsive systems at PCC, and secure communication infrastructure (Gateway) in the field are required, in addition to all hardware requirements for the DERMS solution.

[7] https://www.smartergridsolutions.com/case-studies/

[8] https://www.epri.com/research/products/000000003002014468

[9] https://sepapower.org/resource/distributed-energy-resource-management-system-derms-requirements/

i. *Advanced sensor telemetry* that supports the real time power flow by enabling accurate distribution system station estimation – given the lack of visibility into distribution circuits, state estimation algorithms would need to be deployed which typically require telemetry from select points on each circuit. AMI metering data is not suitable for this due to the latency and time synchronicity requirements which AMI typically cannot meet)

ii. *Remote control capabilities* for system components such as capacitors, regulators, load tap changing ("LTC") transformers, bus bar tie breakers, tie switches and more. Most systems, such as LTC transformers currently operate with local controls. However, once active management of large portions of the DER on the system is in place, the utility must ensure that these systems are not working against the DER optimization. Therefore, a holistic control is needed.

iii. A *reliable and secure communication infrastructure* to each of the assets. Given the fact that with a dynamic control program, stable operation is dependent on active intervention by the control system to curtail resources, security and reliability of the communication infrastructure is paramount. In this case, the requirements distinguish themselves greatly from a scenario where grid investments are planned to ensure that there is enough capacity for any operating scenario.

The AGO has hinted at the idea of testing such a Dynamic Power Curtailment solution within Massachusetts to assess its effectiveness. This kind of test, in a controlled and unconstrained environment, can be accomplished with a significantly simpler solution than described above. A limited test deployment could, for example, be achieved through deployment of a Real-Time Automation Controller (RTAC) with several DER sites on a single circuit and a less operationalized optimization of dispatch.

Question 18: Would any amendments or attachments to the ISA be necessary to implement the program?

Yes, based on the Company's understanding of the proposal for a Dynamic Curtailment Program, the ISA would require amendments or attachments to its current form to:

(1) mitigate financial risk and prevent excessive curtailment for the developer community; and

(2) ensure safe, reliable, stable operation and operational flexibility for the Distribution Company.

Such changes should include topics such as:

- *Technical Requirements* would have to be amended to reflect needs in areas such as hardware, communications, and cyber security.

- *Annual Curtailment Limits*: To ensure that developers can perform a reliable financial forecast and make prudent investment decisions they need to be assured of the maximum lost or curtailed energy output on an annual basis. As such, curtailment limits in terms of the annual output (based of the installed site capacity) would be required. The Distribution Company would apply those limits within its Optimal Power Flow to ensure resources are not curtailed beyond those limits.

Consideration should be made for curtailment beyond the contractual limits if force majeure requires emergency action on behalf of the Distribution Company. Considerations should be made around such exclusions, as well as revenue compensation mechanisms. The treatment of such costs within the utility's revenue requirements would warrant further discussion. Consideration would <u>not</u> be required for the maximum MW curtailment at any point in time, as long as there is an annual curtailment MWh limit.

Some additional issues that may require ISA amendment include:

- *Penalty Framework*: The Distribution Company would monitor, in real time, DER output and compare the measured output to the setpoints provided in the active curtailment. Should the DER fail to comply with control signals due to negligence by the site owner/operator, a penalty framework needs to be in place. This is essential to the concept, as the dynamic curtailment assumes that DERs are part of the electric distribution system, much like any other piece of hardware, with the same responsibilities to maintain safe operations. Failure to perform those responsibilities can lead to system outages, unsafe operating environments, and in the worst-case damage to property or persons.

- *Special Considerations for Storage Systems*: Unlike solar sites (for example) that will always produce at maximum capability given the chance, storage systems are very flexible and have a large potential for participating in bulk energy markets. Therefore, a special consideration is required for these systems in a dynamic curtailment approach, which may include:

  (a) *Optimized Control Through the Distribution Company*: In this concept, the utility dispatches the storage at all times, not just during curtailment activities, within contractual limits outlined in the ISA. The Optimal Power Flow used to determine dispatch would operate with the objective to maximize revenue from the storage site while being bound by local system constraints. Profits from the storage site would be credited to the site owner. This has the distinct benefit

that the distribution utility is fully aware of any applicable schedule for the battery storage and can enlist it for services to the grid to its maximum potential.

(b) *Operating Envelope:* In this concept, which is widely utilized in mainland Europe and Australia,[10,11] the Distribution Company uses its Optimal Power Flow Capabilities to publish day ahead and intra-day operating envelopes for the storage systems. Within those envelopes, the storage systems are free to move and optimize themselves.

- *Special Considerations for Aggregator (Virtual Power Plant) Controlled DER*: Resources sites and interconnected DER under a dynamic curtailment program that are managed by a third-party aggregator or virtual power plant could end up with a conflict of interest between curtailment orders and bulk system market commitments. Here, the Operating Envelope concept would provide the only valid solution.

Question 19: Identify any potential Capital Investment Projects that could be constructed/installed in the near-term based on the current DG interconnection queue.

Although the Eversource Group Distribution and Affected System Operator (Transmission) studies are ongoing, based on a preliminary assessment of existing capacities at DER saturated stations, the Company projects the following stations will need to be upgraded to these applicable configurations.

- The area with the highest penetration of DER in the Eversource Service Territory is the South Eastern region of Massachusetts ("SEMA"). For the purpose of DER studies, the area was divided into six groups (Marion-Fairhaven, Plymouth, Cape, Freetown, Dartmouth-Westport, and New Bedford), each group consisting of 1 to

[10] https://www.bdew.de/media/documents/Stn_20150310_Smart-Grids-Traffic-Light-Concept_english.pdf
[11] https://arena.gov.au/knowledge-bank/on-the-calculation-and-use-of-dynamic-operating-envelopes/

7 substations depending on the characteristics of the distribution system and the amount of DER penetration.

Table 3, below, shows needed capital investment identified by Eversource that can be constructed/installed in the near-term based on the current DG interconnection queue and as part of a DER Group study approach. Table 3 includes 10 substations in the SEMA area and 1 in the Western Massachusetts area, all included in DER groups. The table also includes the existing Bulk Distribution Substation Configuration (number and size of transformers) and the proposed substation configuration as part of a Comprehensive Group Solution.

Table 3: Near-Term Capital Investment Projects Based on DG Interconnection Queue

Station	Existing	Comprehensive Upgrade Necessary
Wing Lane 624	(1) 40MVA (1) 35MVA	(2) 62.5MVA
Rochester 745	(2) 12.5MVA	(2) 62.5MVA
Fisher Road 657	(2) 20MVA	(2) 62.5MVA
West Pond 737	(2) 50MVA	(3) 75MVA
Crystal Spring 646	(1) 40MVA	(2) 62.5MVA
Tremont 713	(2) 50MVA	(3) 75MVA
Wareham 714	(1) 50MVA	(3) 75MVA
Bell Rock 661	(2) 25MVA (34.5kV)	115kV Switching
Assonet 647	(2) 15MVA (13.2kV)	(3) 62.5MVA
Industrial Park 636	(2) 50MVA	(3) 62.5MVA
Blandford 19J (WMA)	(1) 30MVA (1) 25MVA	(2) 62.5MVA

III. STAKEHOLDER PROCESS

As noted above, Eversource strongly supports the Department's initiative to open this investigation and provide a thorough and well-conceived Straw Proposal as the starting point. In prior comments in D.P.U. 19-55 on the subject of cost allocation, Eversource recommended that the Department and stakeholders consider Massachusetts DG-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.

In that regard, 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 DG resources is an important, but not exclusive, goal that will continue to impact the electric power system into the future. A Stakeholder Input Process would be an important part of the Department's overall program to promote penetration of DG facilities. There are two junctures in the planning process where the input of the Stakeholder Input Process would have value.

First, Eversource recommends that the Stakeholder Input Process would be an appropriate and useful venue to allow the Company to obtain data and information on public-policy related inputs to the load forecasting process in areas such as DG, electric vehicles and electrification. Input obtained through this process would be factored into the Company's forecast process for customer load.

Second, Eversource recommends that the Stakeholder Input Process could provide the forum for Eversource to present a full perspective on the opportunities for DG penetration across the system based on the forecast (which would incorporate the inputs obtained in the first step). Eversource would presents results by station and would provide stakeholders with the supporting engineering rational and reasoning that yields results for each station so that there is clarity on the basis for the selection of station opportunities. Eversource would discuss and take input on the various alternatives that might be available to address the system requirement. Eversource would then incorporate input from stakeholders into its final decision on projects and would have an obligation to present the basis for all of its decisions, along with a compilation of stakeholder input, to the Department in the annual filing for approval of particular project selections. The Department should also establish a timeline for this process with prescribed intervals for input and action to enable the annual filing with the Department.

IV. CONCLUSION

As noted above, Eversource supports the Department's initiative to commence a review of a thorough and well-conceived Straw Proposal. 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, and the integration of renewable DG resources is an important, but not exclusive, goal that will continue to impact the electric power system. Eversource appreciates the opportunity to provide these comments on the Straw Proposal, to offer recommendations for the Department's consideration, and looks forward to fully participating in the Department's ongoing considerations in this proceeding.

Respectfully Submitted,

NSTAR ELECTRIC COMPANY
d/b/a EVERSOURCE ENERGY

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Dated: December 23, 2020

Information Request 1: Please propose an optimal format for the 10-year distribution assessment. Including all substantive information points that should be contained in the assessment. Please include a proposal on the frequency with which such assessment should be conducted.

Response:

In proposing a 10-year distribution assessment, Eversource is considering short-term and long-term upgrades to the EPS that will meet the capacity, reliability, and operational flexibility required to serve all customers. One of Eversource's key planning objectives is to provide the same level of safe, reliable service to DER customers that we provide to our load customers. This implies that the EPS should preserve the safety and reliability under normal conditions, emergency conditions, and scheduled maintenance conditions.

To meet this requirement, Eversource is proposing complete distribution assessment of the system on a yearly basis. The following key steps are proposed for the format of the assessment:

a. *Define and identify the need for a DER group study*. An optimal format for the 10-year distribution assessment is for a Group Study to be completed in areas of medium and high DER saturation. This starts by identifying geographic areas that experience high DER penetration and that are expected to saturate due to existing and in-queue DER. Distribution bulk substations and associated distribution circuits in these areas are assigned to a study group based on physical location, topology, load, transfer capability, reliability, and capacity dependency with nearby substations.

b. *Aggregate all Existing and Future DER output*. The next step is to estimate the amount of large- and small-scale DER output, existing and future, that is expected within each DER group.

c. *Determine Distribution Upgrades*. Necessary upgrades required to accommodate the existing and future DER interconnections are determined and documented. Future substation reinforcements are determined after completion of detailed load flow and transient analysis studies that account for substation firm capacity and emergency transfer capabilities. Final reinforcements would result from detailed analyses accounting for capacity, stability, voltage, and reliability constrained conditions that could result from DER saturation.

d. *Define and Allocate System Capacity*. Based on the enabled system capacity from the proposed upgrades, and the existing and future DER projections, a capacity allocation breakdown can be completed for each group. This capacity allocation is similar to those presented in the Company's response to question 3.2: Operational Reserve, Enabled DER Reserve, and Existing Reserve.

e. *Allocate Costs*. Based on this proposal, both Operational Reserve and Enabled DER are categorized as Common System Modifications, and Enabled DER Reserve is categorized as a Capital Investment Project.

Substantive information that should be included in the assessment would encompass the cost per MW for the Group. This value will be calculated using the total cost of the upgrades (Step 1) and allocating it as a ratio of reserved capacity (Step 4). The Final Assessment should include the cost per MW and capacity allocated for Common System Modifications and the Capital Investment Projects.

Information Request 2: Please indicate the length of time required to update hosting capacity maps to reflect additional capacity built into the system after planned projects have been approved by the Department.

Response:

Eversource currently publishes hosting capacity maps, updated periodically (every month), that show spare capacity for new DER on our distribution feeders and bulk substations (based in N-1 capacity constraints). Once additional capacity is built into the system or modifications are made, Geographical Information System ("GIS") maps are updated, and the hosting capacity calculations can be updated at the next cycle.

For planned projects, a hosting capacity process is not yet developed as Eversource currently updates hosting capacity maps only after capacity is built. However, if the Department is considering instituting a separate *hosting capacity map based on Planned Capacity*, Eversource would be willing to work with the Department to develop a clear, consistent process with reasonable timelines.

Every capital project goes through our project approval process. After a project is conceptually approved for execution, a preliminary nomenclature diagram is issued within a few weeks (about 30 days, although there is no strict time limit) which will show the proposed changes to the substation. However, note that GIS maps will not be updated until after the project is in service. Presumably, the hosting capacity calculations can be updated based on the preliminary nomenclature diagram, but this will be a distinct and separate process from the actual Hosting Capacity values which are based on the as-built system represented in the GIS.

NSTAR Electric Company d/b/a Eversource Energy
Department of Public Utilities
D.P.U. 20-75
Information Request 1
December 4, 2020
Person Responsible: Brian Rice

Information Request 1

For illustrative purposes, please provide an estimated annual cap on the Reconciling Fee for the last five calendar years (based on its description in the Straw Proposal).

Response

The Company assumes the Reconciling "Fee" refers to a charge assessed to all customers to cover the costs of Capital Investment Projects not offset by Capital Investment Project Fees from Interconnecting Customers. The straw proposal suggests that the annual change in the cumulative revenue requirement associated with net investment in Capital Investment Projects be capped at 1.5 percent of distribution company revenue. Based on an illustrative historical assessment, Eversource expects the proposed cap will accommodate anticipated capital investment to enable further integration of distributed generation.

The Company cannot provide a direct historical assessment of the revenue requirement associated with Capital Investment Projects since the distribution planning process contemplated to identify such projects has not been in place. The current interconnection tariff has resulted in interconnecting customers funding substantially all of the system modification costs identified to be necessary for their interconnection to the Company's distribution system. The Company has not proactively sought to identify parallel system upgrades as part of the current interconnection process. The Company's cost allocation proposal, as well as the straw proposal, address future system investment requirements that have emerged with sustained growth in distributed generation on the electric power system that is expected to continue. This alternative also addresses system investment driven by parallel system requirements and state policies that benefit distribution load customers at large in addition to DER customers.

In order to support the further consideration of the Department's straw proposal, Attachment Eversource-1 estimates the maximum net costs of Capital Investment Projects that could have been assessed to all customers over the last five calendar years subject to the proposed cap. As shown in the attached analysis, the annual reconciling charges assessed to all ratepayers could have increased by approximately \$65 - \$78M within a year under the proposed cap.

NSTAR Electric Company d/b/a Eversource Energy
Department of Public Utilities
D.P.U. 20-75
Information Request 1
December 4, 2020
Person Responsible: Brian Rice

The Company expects that the revenue requirement of Capital Investment Projects placed in-service within an annual period would very likely be less than this illustrative cap. The analysis provided by the Company includes illustrative revenue requirements for annual net Capital Investment Project additions of $150 - $300M as a comparison to the proposed cap. The Company stresses these are illustrative calculations that are not representative of a specific Capital Investment Project plan contemplated by Eversource. However, the Company does not expect total investment in Capital Investment Projects will exceed these illustrative thresholds.

Attachment Eversource-1

EVERSOURCE ENERGY
ILLUSTRATIVE CAPITAL INVESTMENT RECONCILING REVENUE

Line	Description		2015	2016	2017	2018	2019	2020
1	Actual Distribution Revenue	FERC Form 1, Page 300, Line 10	$ 2,910,014,774	$ 2,742,874,404	$ 2,662,674,265	$ 2,898,074,333	$ 2,772,846,524	
2	Imputed competitive supply revenue	Competitive supply kWh x Basic Service rate	$ 1,856,792,895	$ 1,498,981,920	$ 1,682,895,555	$ 2,083,315,527	$ 2,000,361,981	
3	Maximum Capital Investment Project Revenue	Line 5 cumulative total		$ 71,502,115	$ 136,202,492	$ 203,429,076	$ 281,201,360	$ 357,017,508
4	Total annual revenue		$ 4,766,807,669	$ 4,313,358,439	$ 4,481,772,312	$ 5,184,818,936	$ 5,054,409,865	
5	**1.5 percent change in Revenue**	**Prior year line 4 x 1.5 percent**		**71,502,115**	**64,700,377**	**67,226,585**	**77,772,284**	**75,816,148**
6	Annual Revenue Requirement @							
7	$150M annual net capital investment	Page 2, Line 29, Columns B through E.	$ 13,671,409	$ 36,832,423	$ 59,320,202	$ 81,154,686	$ 102,354,325	$ 120,109,780
8	$200M annual net capital investment	Page 4, Line 29, Columns B through E.	$ 18,228,545	$ 49,109,898	$ 79,093,602	$ 108,206,248	$ 136,472,433	$ 160,146,373
9	$300M annual net capital investment	Page 6, Line 29, Columns B through E.	$ 27,342,818	$ 73,664,846	$ 118,640,403	$ 162,309,372	$ 204,708,649	$ 240,219,559
10	Annual Change in Revenue Requirement @							
11	$150M annual net capital investment	Line 7 current year - prior year	$ 13,671,409	$ 23,161,014	$ 22,487,778	$ 21,834,484	$ 21,199,639	$ 17,755,455
12	$200M annual net capital investment	Line 8 current year - prior year	$ 18,228,545	$ 30,881,352	$ 29,983,705	$ 29,112,646	$ 28,266,185	$ 23,673,940
13	$300M annual net capital investment	Line 9 current year - prior year	$ 27,342,818	$ 46,322,028	$ 44,975,557	$ 43,668,968	$ 42,399,277	$ 35,510,910

Attachment Eversource-1

ILLUSTRATIVE ANNUAL REVENUE REQUIREMENT

SUMMARY OF REVENUE REQUIREMENT @ $150M

Line	Description	Investment Year 1 2015	Investment Year 2 2016	Investment Year 3 2017	Investment Year 4 2018	Investment Year 5 2019	Investment Year 6 2020	Reference
13	(A)	(B)	(C)	(D)	(E)	(F)	(E)	(L)
15	Beginning Gross Plant	-	$ 150,000,000	$ 300,000,000	$ 450,000,000	$ 600,000,000	$ 750,000,000	Line 16 Prior Year
16	Investment Activity	$ 150,000,000	$ 150,000,000	$ 150,000,000	$ 150,000,000	$ 150,000,000	$ 150,000,001	Line 15 + Line 16
17	Ending Gross Plant	$ 150,000,000	$ 300,000,000	$ 450,000,000	$ 600,000,000	$ 750,000,000	$ 900,000,001	Line 15 + Line 16
18	Accumulated Depreciation	$ (3,000,000)	$ (12,000,000)	$ (27,000,000)	$ (48,000,000)	$ (75,000,000)	$ (105,000,000)	Line 18 Prior Year - Line 37
19	Current Net Plant	$ 147,000,000	$ 288,000,000	$ 423,000,000	$ 552,000,000	$ 675,000,000	$ 795,000,001	Line 18 + Line 19
20	Deferred Income Taxes	$ (717,150)	$ (2,753,446)	$ (5,886,777)	$ (9,912,242)	$ (14,639,695)	$ (19,176,591)	Page 3, Line 46
21	Current Rate Base	$ 146,282,850	$ 285,246,554	$ 417,113,223	$ 542,087,758	$ 660,360,305	$ 775,823,410	Line 20 + Line 21
23	Average Rate Base	$ 73,141,425	$ 215,764,702	$ 351,179,888	$ 479,600,490	$ 601,224,031	$ 718,091,857	Avg of Line 21 Prior Year + Current Year
24	Pre-Tax WACC	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	Page 8, Line 18
25	Return on Capital Investment	$ 6,831,409	$ 20,152,423	$ 32,800,202	$ 44,794,686	$ 56,154,325	$ 67,069,779	Line 23 x Line 24
27	Depreciation Expense	$ 3,000,000	$ 9,000,000	$ 15,000,000	$ 21,000,000	$ 27,000,000	$ 30,000,000	Page 3 Line 41
28	Property Taxes	$ 3,840,000	$ 7,680,000	$ 11,520,000	$ 15,360,000	$ 19,200,000	$ 23,040,000	Line 17 x Page 3, Line 49 Col. B
29	Annual Revenue Requirement	$ 13,671,409	$ 36,832,423	$ 59,320,202	$ 81,154,686	$ 102,354,325	$ 120,109,780	Line 25 + Sum of Lines 27-28

Sources
Col. B, Line 16: Investment @ $150 M.
Col. B, Line 23: (Col. B, Line 21) / 2

Attachment Eversource-1

ILLUSTRATIVE ANNUAL REVENUE REQUIREMENT

TAXES @ $150M

Line	Description (A)	Investment Year 1 2015 (B)	Investment Year 2 2016 (C)	Investment Year 3 2017 (D)	Investment Year 4 2018 (E)	Investment Year 5 2019 (F)	Investment Year 6 2020 (G)	Reference (L)
15	MACRS 20 Years							
16	Tax Depreciation Rate (Year 1 Investment)	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	IRS Pub 946
17	Tax Depreciation Rate (Year 2 Investment)		3.75%	7.22%	6.68%	6.18%	5.71%	
18	Tax Depreciation Rate (Year 3 Investment)			3.75%	7.22%	6.68%	6.18%	
19	Tax Depreciation Rate (Year 4 Investment)				3.75%	7.22%	6.68%	
20	Tax Depreciation Rate (Year 5 Investment)					3.75%	7.22%	
23	Tax Depreciation (MACRS 20 Years)							
24	Tax Depreciation (Year 1 Investments)	$ (5,625,000)	$ (10,828,500)	$ (10,015,500)	$ (9,265,500)	$ (8,569,500)	$ (7,927,500)	Page 2, Line 16 Col B x Line 16
25	Tax Depreciation (Year 2 Investments)		$ (5,625,000)	$ (10,828,500)	$ (10,015,500)	$ (9,265,500)	$ (8,569,500)	Page 2, Line 16 Col C x Line 17
26	Tax Depreciation (Year 3 Investments)			$ (5,625,000)	$ (10,828,500)	$ (10,015,500)	$ (9,265,500)	Page 2, Line 16 Col D x Line 18
27	Tax Depreciation (Year 4 Investments)				$ (5,625,000)	$ (10,828,500)	$ (10,015,500)	Page 2, Line 16 Col E x Line 19
28	Tax Depreciation (Year 5 Investments)					$ (5,625,000)	$ (10,828,500)	Page 2, Line 16 Col F x Line 20
30	Total Tax Depreciation	$ (5,625,000)	$ (16,453,500)	$ (26,469,000)	$ (35,734,500)	$ (44,304,000)	$ (46,606,500)	Sum of Lines 24-28
31	Accumulated Tax Depreciation	$ (5,625,000)	$ (22,078,500)	$ (48,547,500)	$ (84,282,000)	$ (128,586,000)	$ (175,192,500)	Cumulative total for Line 30
34	Book Depreciation (25 Year Life)							
35	Book Depreciation (Year 1 Investment)	$ (3,000,000)	$ (6,000,000)	$ (6,000,000)	$ (6,000,000)	$ (6,000,000)	$ (6,000,000)	Page 2, Line 16 Col B x Line 51 (x 1/2 in Yr 1)
36	Book Depreciation (Year 2 Investment)	$ -	$ (3,000,000)	$ (6,000,000)	$ (6,000,000)	$ (6,000,000)	$ (6,000,000)	Page 2, Line 16 Col C x Line 51 (x 1/2 in Yr 1)
37	Book Depreciation (Year 3 Investment)	$ -	$ -	$ (3,000,000)	$ (6,000,000)	$ (6,000,000)	$ (6,000,000)	Page 2, Line 16 Col D x Line 51 (x 1/2 in Yr 1)
38	Book Depreciation (Year 4 Investment)	$ -	$ -	$ -	$ (3,000,000)	$ (6,000,000)	$ (6,000,000)	Page 2, Line 16 Col E x Line 51 (x 1/2 in Yr 1)
39	Book Depreciation (Year 5 Investment)	$ -	$ -	$ -	$ -	$ (3,000,000)	$ (6,000,000)	Page 2, Line 16 Col F x Line 51 (x 1/2 in Yr 1)
41	Total Book Depreciation	$ (3,000,000)	$ (9,000,000)	$ (15,000,000)	$ (21,000,000)	$ (27,000,000)	$ (30,000,000)	Sum of Lines 35 - 39
42	Accumulated Book Depreciation	$ (3,000,000)	$ (12,000,000)	$ (27,000,000)	$ (48,000,000)	$ (75,000,000)	$ (105,000,000)	Cumulative total for Line 41
44	Book/Tax Depreciation Difference	$ (2,625,000)	$ (10,078,500)	$ (21,547,500)	$ (36,282,000)	$ (53,586,000)	$ (70,192,500)	Line 31 - Line 42
45	Effective Tax Rate	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	Page 8 Line 24
46	Accumulated Deferred Income Taxes	$ (717,150)	$ (2,753,446)	$ (5,886,777)	$ (9,912,242)	$ (14,639,695)	$ (19,176,591)	Line 44 x Line 45
48	Other assumptions							
49	Property Tax Rate	2.56%						D.P.U. 17-05
50	Book depreciation years	25.0						Input
51	Book depreciation rate	4.0%						100% / Line 50

Attachment Eversource-1

ILLUSTRATIVE ANNUAL REVENUE REQUIREMENT

SUMMARY OF REVENUE REQUIREMENT @ $200M

Line	Description	Investment Year 1 2015	Investment Year 2 2016	Investment Year 3 2017	Investment Year 4 2018	Investment Year 5 2019	Investment Year 6 2020	Reference
13	(A)	(B)	(C)	(D)	(E)	(F)	(E)	(L)
14								
15	Beginning Gross Plant	-	$ 200,000,000	$ 400,000,000	$ 600,000,000	$ 800,000,000	$ 1,000,000,000	Line 16 Prior Year
16	Investment Activity	$ 200,000,000	$ 200,000,000	$ 200,000,000	$ 200,000,000	$ 200,000,000	$ 200,000,001	Line 15 + Line 16
17	Ending Gross Plant	$ 200,000,000	$ 400,000,000	$ 600,000,000	$ 800,000,000	$ 1,000,000,000	$ 1,200,000,001	Line 15 + Line 16
18	Accumulated Depreciation	$ (4,000,000)	$ (16,000,000)	$ (36,000,000)	$ (64,000,000)	$ (100,000,000)	$ (140,000,000)	Line 18 Prior Year - Line 37
19	Current Net Plant	$ 196,000,000	$ 384,000,000	$ 564,000,000	$ 736,000,000	$ 900,000,000	$ 1,060,000,001	Line 18 + Line 19
20	Deferred Income Taxes	$ (956,200)	$ (3,671,262)	$ (7,849,036)	$ (13,216,323)	$ (19,519,594)	$ (25,568,788)	Page 5, Line 46
21	Current Rate Base	$ 195,043,800	$ 380,328,738	$ 556,150,964	$ 722,783,677	$ 880,480,406	$ 1,034,431,213	Line 20 + Line 21
22								
23	Average Rate Base	$ 97,521,900	$ 287,686,269	$ 468,239,851	$ 639,467,320	$ 801,632,042	$ 957,455,810	Avg of Line 21 Prior Year + Current Year
24	Pre-Tax WACC	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	Page 8, Line 18
25	Return on Capital Investment	$ 9,108,545	$ 26,869,898	$ 43,733,602	$ 59,726,248	$ 74,872,433	$ 89,426,373	Line 23 x Line 24
26								
27	Depreciation Expense	$ 4,000,000	$ 12,000,000	$ 20,000,000	$ 28,000,000	$ 36,000,000	$ 40,000,000	Page 5 Line 41
28	Property Taxes	$ 5,120,000	$ 10,240,000	$ 15,360,000	$ 20,480,000	$ 25,600,000	$ 30,720,000	Line 17 x Page 5, Line 49 Col. B
29	Annual Revenue Requirement	$ 18,228,545	$ 49,109,898	$ 79,093,602	$ 108,206,248	$ 136,472,433	$ 160,146,373	Line 25 + Sum of Lines 27-28

Sources
Col. B, Line 16: Investment @ $200 M.
Col. B, Line 23: (Col. B, Line 21) / 2

Attachment Eversource-1

ILLUSTRATIVE ANNUAL REVENUE REQUIREMENT

TAXES @ $200M

10		Investment	Investment	Investment	Investment	Investment	Investment	
11		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	
12	Description	2015	2016	2017	2018	2019	2020	Reference
13	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(L)
15	MACRS 20 Years							
16	Tax Depreciation Rate (Year 1 Investment)	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	IRS Pub 946
17	Tax Depreciation Rate (Year 2 Investment)		3.75%	7.22%	6.68%	6.18%	5.71%	
18	Tax Depreciation Rate (Year 3 Investment)			3.75%	7.22%	6.68%	6.18%	
19	Tax Depreciation Rate (Year 4 Investment)				3.75%	7.22%	6.68%	
20	Tax Depreciation Rate (Year 5 Investment)					3.75%	7.22%	
23	Tax Depreciation (MACRS 20 Years)							
24	Tax Depreciation (Year 1 Investments)	$ (7,500,000)	$ (14,438,000)	$ (13,354,000)	$ (12,354,000)	$ (11,426,000)	$ (10,570,000)	Page 4, Line 16 Col B x Line 16
25	Tax Depreciation (Year 2 Investments)		$ (7,500,000)	$ (14,438,000)	$ (13,354,000)	$ (12,354,000)	$ (11,426,000)	Page 4, Line 16 Col C x Line 17
26	Tax Depreciation (Year 3 Investments)			$ (7,500,000)	$ (14,438,000)	$ (13,354,000)	$ (12,354,000)	Page 4, Line 16 Col D x Line 18
27	Tax Depreciation (Year 4 Investments)				$ (7,500,000)	$ (14,438,000)	$ (13,354,000)	Page 4, Line 16 Col E x Line 19
28	Tax Depreciation (Year 5 Investments)					$ (7,500,000)	$ (14,438,000)	Page 4, Line 16 Col F x Line 20
30	Total Tax Depreciation	$ (7,500,000)	$ (21,938,000)	$ (35,292,000)	$ (47,646,000)	$ (59,072,000)	$ (62,142,000)	Sum of Lines 24-28
31	Accumulated Tax Depreciation	$ (7,500,000)	$ (29,438,000)	$ (64,730,000)	$ (112,376,000)	$ (171,448,000)	$ (233,590,000)	Cumulative total for Line 30
34	Book Depreciation (25 Year Life)							
35	Book Depreciation (Year 1 Investment)	$ (4,000,000)	$ (8,000,000)	$ (8,000,000)	$ (8,000,000)	$ (8,000,000)	$ (8,000,000)	Page 4, Line 16 Col B x Line 51 (x 1/2 in Yr 1)
36	Book Depreciation (Year 2 Investment)	$ -	$ (4,000,000)	$ (8,000,000)	$ (8,000,000)	$ (8,000,000)	$ (8,000,000)	Page 4, Line 16 Col C x Line 51 (x 1/2 in Yr 1)
37	Book Depreciation (Year 3 Investment)	$ -	$ -	$ (4,000,000)	$ (8,000,000)	$ (8,000,000)	$ (8,000,000)	Page 4, Line 16 Col D x Line 51 (x 1/2 in Yr 1)
38	Book Depreciation (Year 4 Investment)	$ -	$ -	$ -	$ (4,000,000)	$ (8,000,000)	$ (8,000,000)	Page 4, Line 16 Col E x Line 51 (x 1/2 in Yr 1)
39	Book Depreciation (Year 5 Investment)	$ -	$ -	$ -	$ -	$ (4,000,000)	$ (8,000,000)	Page 4, Line 16 Col F x Line 51 (x 1/2 in Yr 1)
41	Total Book Depreciation	$ (4,000,000)	$ (12,000,000)	$ (20,000,000)	$ (28,000,000)	$ (36,000,000)	$ (40,000,000)	Sum of Lines 35 - 39
42	Accumulated Book Depreciation	$ (4,000,000)	$ (16,000,000)	$ (36,000,000)	$ (64,000,000)	$ (100,000,000)	$ (140,000,000)	Cumulative total for Line 41
44	Book/Tax Depreciation Difference	$ (3,500,000)	$ (13,438,000)	$ (28,730,000)	$ (48,376,000)	$ (71,448,000)	$ (93,590,000)	Line 31 - Line 42
45	Effective Tax Rate	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	Page 8 Line 24
46	Accumulated Deferred Income Taxes	$ (956,200)	$ (3,671,262)	$ (7,849,036)	$ (13,216,323)	$ (19,519,594)	$ (25,568,788)	Line 44 x Line 45
48	Other assumptions							
49	Property Tax Rate	2.56%						D.P.U. 17-05
50	Book depreciation years	25						Input
51	Book depreciation rate	4.0%						100% / Line 50

Attachment Eversource-1

ILLUSTRATIVE ANNUAL REVENUE REQUIREMENT

SUMMARY OF REVENUE REQUIREMENT @ $300M

Line	Description	Investment Year 1 2015	Investment Year 2 2016	Investment Year 3 2017	Investment Year 4 2018	Investment Year 5 2019	Investment Year 6 2020	Reference
13	(A)	(B)	(C)	(D)	(E)	(F)	(E)	(L)
15	Beginning Gross Plant	-	$ 300,000,000	$ 600,000,000	$ 900,000,000	$ 1,200,000,000	$ 1,500,000,000	Line 16 Prior Year
16	Investment Activity	$ 300,000,000	$ 300,000,000	$ 300,000,000	$ 300,000,000	$ 300,000,000	$ 300,000,000	Line 15 + Line 16
17	Ending Gross Plant	$ 300,000,000	$ 600,000,000	$ 900,000,000	$ 1,200,000,000	$ 1,500,000,000	$ 1,800,000,000	Line 15 + Line 16
18	Accumulated Depreciation	$ (6,000,000)	$ (24,000,000)	$ (54,000,000)	$ (96,000,000)	$ (150,000,000)	$ (210,000,000)	Line 18 Prior Year - Line 37
19	Current Net Plant	$ 294,000,000	$ 576,000,000	$ 846,000,000	$ 1,104,000,000	$ 1,350,000,000	$ 1,590,000,000	Line 18 + Line 19
20	Deferred Income Taxes	$ (1,434,300)	$ (5,506,892)	$ (11,773,554)	$ (19,824,485)	$ (29,279,390)	$ (38,353,182)	Page 7, Line 46
21	Current Rate Base	$ 292,565,700	$ 570,493,108	$ 834,226,446	$ 1,084,175,515	$ 1,320,720,610	$ 1,551,646,818	Line 20 + Line 21
23	Average Rate Base	$ 146,282,850	$ 431,529,404	$ 702,359,777	$ 959,200,981	$ 1,202,448,062	$ 1,436,183,714	Avg of Line 21 Prior Year + Current Year
24	Pre-Tax WACC	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	Page 8, Line 18
25	Return on Capital Investment	$ 13,662,818	$ 40,304,846	$ 65,600,403	$ 89,589,372	$ 112,308,649	$ 134,139,559	Line 23 x Line 24
27	Depreciation Expense	$ 6,000,000	$ 18,000,000	$ 30,000,000	$ 42,000,000	$ 54,000,000	$ 60,000,000	Page 7, Line 41
28	Property Taxes	$ 7,680,000	$ 15,360,000	$ 23,040,000	$ 30,720,000	$ 38,400,000	$ 46,080,000	Line 17 x Page 7, Line 49 Col. B
29	Annual Revenue Requirement	$ 27,342,818	$ 73,664,846	$ 118,640,403	$ 162,309,372	$ 204,708,649	$ 240,219,559	Line 25 + Sum of Lines 27-28

Sources
Col. B, Line 16: Investment @ $300 M.
Col. B, Line 23: (Col. B, Line 21) / 2

ILLUSTRATIVE ANNUAL REVENUE REQUIREMENT

TAXES @ $300M

Line	Description (A)	Investment Year 1 2015 (B)	Investment Year 2 2016 (C)	Investment Year 3 2017 (D)	Investment Year 4 2018 (E)	Investment Year 5 2019 (F)	Investment Year 6 2020 (G)	Reference (L)
15	MACRS 20 Years							
16	Tax Depreciation Rate (Year 1 Investment)	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	IRS Pub 946
17	Tax Depreciation Rate (Year 2 Investment)		3.75%	7.22%	6.68%	6.18%	5.71%	
18	Tax Depreciation Rate (Year 3 Investment)			3.75%	7.22%	6.68%	6.18%	
19	Tax Depreciation Rate (Year 4 Investment)				3.75%	7.22%	6.68%	
20	Tax Depreciation Rate (Year 5 Investment)					3.75%	7.22%	
23	Tax Depreciation (MACRS 20 Years)							
24	Tax Depreciation (Year 1 Investments)	$ (11,250,000)	$ (21,657,000)	$ (20,031,000)	$ (18,531,000)	$ (17,139,000)	$ (15,855,000)	Page 6, Line 16 Col B x Line 16
25	Tax Depreciation (Year 2 Investments)		$ (11,250,000)	$ (21,657,000)	$ (20,031,000)	$ (18,531,000)	$ (17,139,000)	Page 6, Line 16 Col C x Line 17
26	Tax Depreciation (Year 3 Investments)			$ (11,250,000)	$ (21,657,000)	$ (20,031,000)	$ (18,531,000)	Page 6, Line 16 Col D x Line 18
27	Tax Depreciation (Year 4 Investments)				$ (11,250,000)	$ (21,657,000)	$ (20,031,000)	Page 6, Line 16 Col E x Line 19
28	Tax Depreciation (Year 5 Investments)					$ (11,250,000)	$ (21,657,000)	Page 6, Line 16 Col F x Line 20
30	Total Tax Depreciation	$ (11,250,000)	$ (32,907,000)	$ (52,938,000)	$ (71,469,000)	$ (88,608,000)	$ (93,213,000)	Sum of Lines 24-28
31	Accumulated Tax Depreciation	$ (11,250,000)	$ (44,157,000)	$ (97,095,000)	$ (168,564,000)	$ (257,172,000)	$ (350,385,000)	Cumulative total for Line 30
34	Book Depreciation (25 Year Life)							
35	Book Depreciation (Year 1 Investment)	$ (6,000,000)	$ (12,000,000)	$ (12,000,000)	$ (12,000,000)	$ (12,000,000)	$ (12,000,000)	Page 6, Line 16 Col B x Line 51 (x 1/2 in Yr 1)
36	Book Depreciation (Year 2 Investment)	$ -	$ (6,000,000)	$ (12,000,000)	$ (12,000,000)	$ (12,000,000)	$ (12,000,000)	Page 6, Line 16 Col C x Line 51 (x 1/2 in Yr 1)
37	Book Depreciation (Year 3 Investment)	$ -	$ -	$ (6,000,000)	$ (12,000,000)	$ (12,000,000)	$ (12,000,000)	Page 6, Line 16 Col D x Line 51 (x 1/2 in Yr 1)
38	Book Depreciation (Year 4 Investment)	$ -	$ -	$ -	$ (6,000,000)	$ (12,000,000)	$ (12,000,000)	Page 6, Line 16 Col E x Line 51 (x 1/2 in Yr 1)
39	Book Depreciation (Year 5 Investment)	$ -	$ -	$ -	$ -	$ (6,000,000)	$ (12,000,000)	Page 6, Line 16 Col F x Line 51 (x 1/2 in Yr 1)
41	Total Book Depreciation	$ (6,000,000)	$ (18,000,000)	$ (30,000,000)	$ (42,000,000)	$ (54,000,000)	$ (60,000,000)	Sum of Lines 35 - 39
42	Accumulated Book Depreciation	$ (6,000,000)	$ (24,000,000)	$ (54,000,000)	$ (96,000,000)	$ (150,000,000)	$ (210,000,000)	Cumulative total for Line 41
44	Book/Tax Depreciation Difference	$ (5,250,000)	$ (20,157,000)	$ (43,095,000)	$ (72,564,000)	$ (107,172,000)	$ (140,385,000)	Line 31 - Line 42
45	Effective Tax Rate	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	Page 8 Line 24
46	Accumulated Deferred Income Taxes	$ (1,434,300)	$ (5,506,892)	$ (11,773,554)	$ (19,824,485)	$ (29,279,390)	$ (38,353,182)	Line 44 x Line 45
48	Other assumptions							
49	Property Tax Rate	2.56%						D.P.U. 17-05
50	Book depreciation years	25.00						Input
51	Book depreciation rate	4.0%						100% / Line 50

RETURN ON RATE BASE AND CAPITAL STRUCTURE

Line	Description (A)	Capital Ratio (B)	Cost (C)	Weighted Cost Col (B) / Col (C) (D)	Tax Gross-up Factor (E)	Pre-Tax Rate of Return Col (D) / Col (E) (F)
14	Long-Term Debt	45.67%	4.21%	1.92%		1.92%
15	Preferred Stock	0.74%	4.56%	0.03%	72.68%	0.04%
16	Common Equity	53.59%	10.00%	5.36%	72.68%	7.37%
18	Total	100.00%		7.31%		9.34%
20	Tax Gross-up Factor:					
21	Federal Rate					21.00%
22	State Rate					8.00%
23	Effective State Rate = State Rate * (1 - Federal Rate)					6.32%
24	Effective State and Federal Tax Rate				T	27.32%
25	Net Income After Taxes on Income				1 - T	72.68%
26	State and Federal Taxes / Net Income After Taxes on Income				T / (1 - T)	37.59%

Sources
Col. B, Line 14: Page 9, Line 2, Col. C.
Col. B, Line 15: Page 9, Line 3, Col. C.
Col. B, Line 16: Page 9, Line 4, Col. C.
Col. C, Line 14: Page 9, Line 2, Col. D.
Col. C, Line 15: Page 9, Line 3, Col. D.
Col. C, Line 16: Page 9, Line 4, Col. D.

NSTAR Electric Company d/b/a Eversource Energy
Department of Public Utilities
D.P.U. 20-75
Information Request 2
December 4, 2020
Person Responsible: Brian Rice

Information Request 2

For each of the last ten years, provide estimates of the following:

a. The minimum, maximum, median, and average system modification cost for Facilities using the expedited and standard interconnection processes. Please also provide the total number and capacity of Facilities using the expedited and standard interconnection process that have applied by year and the cumulative total system modification costs charged to Facilities in each year.

b. The minimum, maximum, median, and average system modification cost for Facilities using the simplified interconnection process. Please also provide the total number and capacity of Facilities using the simplified interconnection process that have applied by year and the cumulative total system modification costs charged to Facilities in each year.

Response

Please refer to Attachment Eversource-2 for a summary of system modification costs for facilities using the simplified, expedited and standard interconnection processes. Eversource has incurred system modification costs to support interconnection of facilities using the simplified interconnection process but has not historically applied those costs to facilities. The Company is also unable to retrieve information on system modification costs for facilities using expedited and standard processes prior to 2013.

EVERSOURCE ENERGY
Simplified Interconnection Process Summary

Year	Eastern MA		Western MA	
	Applications	Capacity (kW)	Applications	Capacity (kW)
2010	347	1,932	103	423
2011	685	3,950	222	1,124
2012	1,996	11,813	345	1,664
2013	2,156	13,265	413	2,441
2014	4,603	30,199	1,276	7,999
2015	7,234	49,999	2,643	17,690
2016	5,870	44,460	2,588	18,504
2017	3,937	30,770	2,163	15,727
2018	4,121	33,820	2,082	14,069
2019	4,528	38,440	1,804	11,981
2020	4,476	39,764	1,331	7,187

Attachment Eversource-2

EVERSOURCE ENERGY
Expedited and Standard Interconnection Process Summary

Eastern MA

Year	Applications	Capacity (kW)	System Modification Cost: Cumulative	Minimum	Maximum	Median	Average
2013	1	100	$ -	$ -	$ -	$ -	$ -
2014	73	26,340	$ 1,056,543	$ -	$ 266,656	$ -	$ 14,473
2015	161	59,572	$ 3,823,632	$ -	$ 422,000	$ -	$ 23,749
2016	172	84,874	$ 8,373,775	$ -	$ 453,061	$ 1,025	$ 48,685
2017	87	58,642	$ 8,967,519	$ -	$ 1,758,276	$ -	$ 103,075
2018	106	97,538	$ 9,615,869	$ -	$ 1,097,751	$ 1,473	$ 90,716
2019	335	229,159	$ 27,350,688	$ -	$ 1,661,160	$ -	$ 81,644
2020	297	100,691	$ 8,837,242	$ -	$ 789,445	$ -	$ 29,755

Western MA

Year	Applications	Capacity (kW)	System Modification Cost: Cumulative	Minimum	Maximum	Median	Average
2013	36	10,410	$ 776,663	$ -	$ 368,589	$ -	$ 21,574
2014	24	26,072	$ 1,462,718	$ -	$ 483,642	$ 349	$ 60,947
2015	48	20,041	$ 2,575,699	$ -	$ 579,353	$ 123	$ 53,660
2016	67	48,366	$ 8,929,142	$ -	$ 1,619,411	$ 358	$ 133,271
2017	51	67,231	$ 11,450,291	$ -	$ 1,093,776	$ 153,859	$ 224,516
2018	55	73,921	$ 11,865,864	$ -	$ 1,090,663	$ 22,978	$ 215,743
2019	37	37,318	$ 5,385,942	$ -	$ 888,614	$ -	$ 145,566
2020	50	85,439	$ 16,812,859	$ -	$ 4,054,020	$ 31,526	$ 336,257

Attachment Eversource IR-5

EVERSOURCE ENERGY
Expedited and Standard

Year	Eastern MA			Western MA		
	Application Fees	Study Costs	Construction Costs	Application Fees	Study Costs	Construction Costs
2013	$ 29,175.00	$ -	$ -	$ 56,731.15	$ 554,915.59	$ 776,662.56
2014	$ 270,739.62	$ 39,750.00	$ 1,056,543.00	$ 91,495.50	$ 424,025.92	$ 1,462,718.08
2015	$ 792,132.02	$ 1,262,466.84	$ 3,823,632.12	$ 411,559.43	$ 585,917.31	$ 2,575,698.99
2016	$ 293,212.68	$ 518,858.57	$ 8,373,774.65	$ 266,547.65	$ 2,443,991.72	$ 8,929,141.60
2017	$ 374,450.53	$ 470,065.00	$ 8,967,519.07	$ 503,715.45	$ 2,737,190.08	$ 11,450,291.29
2018	$ 1,135,990.11	$ 1,390,943.25	$ 9,615,869.00	$ 833,779.20	$ 2,446,063.40	$ 11,865,863.77
2019	$ 1,011,552.01	$ 1,839,038.25	$ 27,350,687.91	$ 200,327.28	$ 1,452,683.20	$ 5,385,941.69
2020	$ 593,951.09	$ 5,599,624.83	$ 8,837,241.87	$ 184,972.20	$ 771,280.24	$ 16,812,859.25
TOTAL	$ 4,501,203.06	$ 11,120,746.74	$ 68,025,267.62	$ 2,549,127.86	$ 11,416,067.46	$ 59,259,177.23

*Application fees includes SMART application fees.
*Study costs includes analysis fees, ASO Level 0/1 Study, ASO Level 3 Study, Distribution Group Impact Study, Detailed Studies, Distribution Studies, Dynamic Studies, Impact Studies, Outage Fees, ROI Studies, ROW Fees, Short Circuit Studies, Stability Studies, Supplemental Reviews, and Transmission Studies.
*Application fees, study costs and contstruction costs not recorded for simplified process