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February 5, 2021

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

Re: Investigation by the Department of Public Utilities On Its Own Motion Into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation.

Dear Secretary Marini:

The Massachusetts Office of the Attorney General ("AGO") submits the following reply comments in response to the Vote and Order Opening Investigation soliciting comments. *Vote and Order Opening Investigation,* at 2 (October 22, 2020) (the "Order").

1. Introduction

On October 22, 2020, the Department of Public Utilities (the "Department") opened an investigation, docketed as D.P.U. 20-75, into the Electric Distribution Companies' (the "EDCs") (1) distributed energy resource ("DER") planning and (2) assignment and recovery of costs for the interconnection of distributed generation ("DG").[1] In this docket, the Department seeks comment on its Straw Proposal for a new DER planning process and on methods for cost assignment and recovery associated with DER interconnection.[2] In addition to inviting comments on the Straw Proposal, the Department also poses a number of specific questions to stakeholders, including questions about the AGO's proposed short-term actions regarding cost allocation.[3] A number of interested stakeholders submitted initial comments in response to the Department's Straw Proposal and directed questions.

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[1] The EDCs include three electric distribution companies in Massachusetts: NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; and Fitchburg Gas and Electric Light Company d/b/a Unitil.
[2] *Vote and Order Opening Investigation*, D.P.U. 20-75, at 2, 7–8 (October 22, 2020). While the Massachusetts Standards for Interconnection of Distributed Generation currently focus on DG, DER includes a broader set of technologies, such as energy storage.
[3] *Id*., at 2, 7, Att. A at 16.

The AGO appreciates other stakeholders' thoughtful initial comments and notes that many stakeholders supported the same processes that the AGO proposed in its own Initial Comments. The collective initial comments underscore the need for the Department to set forth a process to operationalize DER interconnection and link cost allocation and collection to the decisions made during interconnection. Indeed, the wide range of DER planning and cost allocation suggestions from other stakeholders highlights how much uncertainty—and therefore potential for inefficient and under-utilized investment—there will be without a structured process. As the AGO noted in its Initial Comments, the AGO recommends additional stakeholder collaboration to further develop initial Capital Investment Project ("CIP") and Common System Modification ("CSM") processes and ensure that a long-term solution is reached. The AGO's reply comments discuss critical features of DER interconnection planning and cost allocation processes, include replies to specific stakeholder concerns, and include additional responsive proposals regarding EDC incentives and ratemaking implications. Although the AGO supports near-term action to integrate DERs through targeted system upgrades, these near-term actions should be accompanied by structured, thoughtful long-term processes.

2. Critical Features of DER Interconnection Planning and Cost Allocation Processes

a. Mitigation Strategies

To ensure that DER is effectively integrated into distribution system planning, the EDCs should employ robust strategies for minimizing distribution system upgrades. Indeed, one of the prevailing issues related to DER planning and integration is the need to develop a process that prioritizes such mitigation solutions. Among other stakeholders, the Department of Energy Resources ("DOER"), in its Initial Comments, noted that mitigation strategies that defer or prevent distribution upgrades can, in turn, lower interconnection costs and facilitate higher DER penetration.[4] DOER further recommended that the Department require that the EDCs demonstrate that every proposed CIP could not reasonably be mitigated or deferred.[5] National Grid's Initial Comments confirmed that DER planning and integration, such as distribution system visibility, real time adjustment, and control, "could avoid the need for certain distribution System Modifications that would be required today."[6] Comprehensive consideration of mitigation strategies within the interconnection and planning processes are key to ensuring cost-effective system upgrades. However, many distribution upgrade mitigation strategies are currently in the consideration or development phase and not readily available, and the availability and timing of certain mitigation strategies will likely vary by EDC.

Several mitigation strategies require additional development and standardization so that they can be integrated holistically into the interconnection and distribution system planning

[4] DOER Initial Comments, at 5 (Dec. 23, 2020).
[5] *Id.*, at 17.
[6] National Grid Initial Comments, at 12 (Dec. 23, 2020).

processes, which will require EDC time and resources. For example, the EDCs can avoid untimely or unnecessary distribution system upgrades by improving load forecasts. One specific load forecasting improvement that the EDCs could make, through the DER Integration Roadmap recommended in the AGO's Initial Comments, is to identify hidden load within forecasts. "Hidden load is the amount of load on a circuit that is masked by distributed generation making the perceived kilovolt-ampere ("kVa") value appear to be lower than it is."[7] Distribution planning could be improved with a more granular understanding of the technical risks that consider hidden load; however, it is unlikely that the EDCs are currently able to accurately model hidden load if they are not currently able to monitor DERs. "To compensate for the [uncertain timing and magnitude of] hidden load, the system may be studied with all DER off-line, as it depicts a scenario where the distribution system must carry the full load without DERs. This makes the analysis less accurate, which may result in unnecessary or less timely system investments."[8] Thus, improving load forecasting with DER monitoring can defer distribution investments. The Department should ensure that various mitigation strategies, such as accurate DER generation and load forecasting, are each prioritized appropriately given the novelty of these processes and technologies.

Dynamic curtailment presents yet another example that demonstrates the importance of prioritizing appropriate mitigation strategies. While the EDCs state in their Initial Comments that they are open to dynamic curtailment, they suggest that the mitigation strategy should be narrowly applied "as a very targeted approach for small to medium capacity deficits"[9] and "in certain circumstances, such as in areas of moderate DG saturation."[10] However, the issue of when and how dynamic curtailment will provide value requires additional, near-term EDC and stakeholder investigation, which could be achieved through the AGO's proposed DER Integration Roadmap. National Grid has begun such investigation through its Active Resource Integration initiative, which explores many issues around dynamic curtailment, including a demonstration pilot at two sites in 2021.[11] Eversource has also asserted that a Real-Time Automation Controller can test a dynamic power curtailment solution more simply, without expensive infrastructure.[12] This information is promising and demonstrates that dynamic curtailment is one of many potential mitigation solutions that should be further developed through distribution system planning and the interconnection processes.

The AGO is concerned that the EDCs will not prioritize cost-effective mitigation strategies in a timely manner when they only envision limited applications for solutions like dynamic curtailment. For example, Eversource argues that dynamic curtailment may not be an

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[7] *PPL Petition for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan*, Pennsylvania Public Utility Commission Docket No. P-2019-3010128, Attachment C (January 19, 2021), *available at* https://www.puc.pa.gov/pcdocs/1690837.pdf.
[8] *Id*.
[9] Eversource Initial Comments, at 38 (Dec. 23, 2020).
[10] National Grid Initial Comments, at 38.
[11] *Id*., at 41–43.
[12] *Id*., at 42–43.

effective near-term mitigation solution for stations heavily saturated with DER.[13] In such cases, however, mitigation solutions can inform *future* system upgrades (*i.e*., dynamic curtailment may allow for better utilization of upgraded assets and therefore require smaller upgrades) and ensure that additional upgrades are avoided in the future to the extent feasible. Grid operators in the UK have found that active network management is an efficient investment for increasing hosting capacity. One new project is expected to free up two gigawatts of hosting capacity with an £8 million investment, resulting in an estimated £4/kW ($5.5/kW) investment for improved capacity utilization.[14] The investment is also expected to yield an estimated potential savings of £250 million.[15] Mitigation investments will likely bring significant value to the Massachusetts distribution system and should be fully integrated into planning and interconnection processes.

b. Cost Allocation

Initial comments from stakeholders[16] alluded to the desire for a more comprehensive and fully-developed distribution system upgrade cost allocation and pricing framework. This desire indicates that such a framework should stem from the need to identify and allocate import and export related costs and the need for multiple pathways for allocating export-related upgrade costs.

Stakeholders also noted that, because distribution system upgrades may serve both DER and load customers (*i.e.*, export and import),[17] identifying, fairly assigning, and collecting different costs from both export and import customers is challenging.[18] To address these concerns, the Department should develop a cost allocation and pricing framework that would account for the costs and benefits associated with both export *and* import so that each can be allocated equitably, as discussed in the AGO's Initial Comments.[19] Developing this more comprehensive cost identification and allocation framework will, among other things, require additional information related to cost causation and the development of pricing options within the interconnection process or export tariffs that reflect such cost causation.

The system modification costs related to DER export need new and varying allocation pathways within the interconnection process. Although some pathways exist today (*i.e*., the Simplified Interconnection process), there may be additional pathways currently available not yet realized and still more that will develop as technology and planning processes mature. An interconnection and export tariff framework with multiple pathways will allow for flexibility

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[13] Eversource Initial Comments, at 38.
[14] John Parnell. "New UK DERMS Project Targets Flexibility Across Distribution and Transmission Grids" January 7, 2021, *available at* https://www.greentechmedia.com/articles/read/new-uk-derms-project-eyes-whole-system-flexibility.
[15] *Id.*
[16] Eversource Initial Comments, at 9; National Grid Initial Comments, at 21; IREC Initial Comments, at 4 (Dec. 23, 2020).
[17] Eversource Initial Comments, at 9.
[18] National Grid Initial Comments, at 21; IREC Initial Comments, at 4.
[19] AGO Initial Comments, at 8–10 (Dec. 23, 2020).

around how DER facilities interact with the distribution grid—and therefore, how the grid should accommodate their interconnection. For example, dual service tariffs that use system monitoring could avoid system upgrades by allowing interconnecting facilities to take non-firm import or export service.[20]

Without additional cost allocation pathways embedded within the interconnection process, the Department's Straw Proposal and other stakeholders' disparate interpretations may fail to capture much of the value that DERs can provide to the distribution grid. Some of stakeholders' fee proposals do not contemplate ways to incent flexible and desirable export behavior.[21] For example, levying a $/kW upfront fee on DER nameplate capacity may impede dynamic curtailment in the future because interconnecting customers will have already paid for their use of the distribution grid and would have little incentive to effectively pay again for system usage by limiting their export. Although National Grid is planning a dynamic curtailment pilot,[22] the Department's proposed interconnection fee structures could disincentivize participation in this interconnection option because the benefit to a developer is unclear and likely non-existent. To remedy this disincentive, facilities should have multiple options to choose varying levels of service (*e.g.*, firm service and service that is dynamically curtailed) at different ongoing monthly costs (like current advanced rate design tariffs for import).

It is possible to establish these options reflecting the differing burdens that interconnecting facilities place on the distribution system now that the Department has proposed that all interconnecting DERs should pay for their incremental system impact. Whereas DERs previously paid for their distribution system use only if they independently triggered a discrete system upgrade, the CIP and CSM fee concepts require all facilities to contribute to distribution system costs. Under this new regulatory paradigm, tariff modifications can appropriately reflect the distribution cost reduction enabled by facilities that allow dynamic curtailment or other service modifications. Reducing those facilities' export-related costs can act as an economic incentive for opting into dynamic curtailment. Facilities need an incentive because an interconnection service that allows curtailment is inferior to and distinct from firm service. The process that the AGO proposed in its Initial Comments would explore dynamic and adaptable export related pricing structures and create a framework to ensure that fees developed now enable flexibility in the future.

Therefore, any potential CSM and CIP fees should have at least a theoretical relationship with a structured cost allocation and pricing framework first—not only to avoid unintended consequences (or multiple interpretations as expressed in the various stakeholder initial comments), as the dynamic curtailment example shows—but also to evolve as necessary. These fees represent a significant change to the regulatory paradigm because they attempt to plan for and fairly allocate export capacity and its cost.[23] Without an overarching export cost allocation

[20] *Id.*, at 9–10.

[21] As noted in the AGO's Initial Comments, export related costs vary temporally, seasonally, and locationally. *Id.* at 9–10.

[22] National Grid Initial Comments, at 43.

[23] AGO Initial Comments, at 7.

and pricing framework, there is room for numerous and piecemeal interpretations of how to pay for export capacity through CIP and CSM fees, including what costs these fees should cover, who should pay for them, and how they should interact. Indeed, stakeholders interpreted both the CSM and CIP fees in many different ways.[24] Without a cost allocation and pricing framework, there may be little means by which the Department can determine equitable cost allocation or efficient export pricing.

In its Initial Comments, the AGO sought to lend structure to the shifting regulatory paradigm by proposing a cost allocation process that would first define export service options and then explore export pricing structures. Although it may not currently be feasible for the EDCs to define and price export services granularly, the CIP and CSM fees could be framed as an interim step to a more dynamic export pricing process, based on a standard stakeholder-developed framework.

3. Responses to Stakeholder Initial Comments

a. Caps for CIP Projects

In its Straw Proposal, the Department asked stakeholders if there should be a cap on the $/kW CIP fees billed to each facility that benefits from a CIP.[25] The AGO agrees with the many stakeholders (including National Grid and Eversource) who asserted that there should be no cap on the $/kW fee assigned for pre-approved CIPs, in order to send an accurate price signal to interconnecting customers.[26] The AGO also agrees with DOER that prioritizing distribution planning—including CIP planning—should help to mitigate and minimize upgrade costs.[27]

The AGO shares DOER's concern that expensive CIP upgrades and fees may drive developers to locate elsewhere and therefore leave CIP investments under-utilized.[28] No fee structure, however, is perfect and every step should be taken to minimize ratepayer risk. Thus, additional investigation is needed to avoid inefficient, wasteful pricing. The AGO encourages exploration of how differing fees, including a flat v. a CIP fee that varies based on hosting capacity, balance the competing needs of upgraded infrastructure and ratepayer cost.

Although the AGO does not endorse a $/kW CIP cap that would artificially limit the price that developers must pay for utilizing a distribution upgrade, the AGO recommends a

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[24] National Grid and Unitil proposed only CSM fees for simplified projects. National Grid Initial Comments, at 26, 33; Unitil Initial Comments, at 9, 11 (December 23, 2020). Eversource proposed ratepayer funded CSM fees to cover "system reliability" that would be separate from freeing up DG capacity. *E*versource Initial Comments at 22. IREC suggested CSM fees for larger projects when upgrades are not covered by CIPs. IREC Initial Comments, at 7. NECEC suggested that CSM fees would cover large project upgrades and also overlap CIPs. NECEC Initial Comments, at 21 (Dec. 23, 2020).
[25] D.P.U. 20-75, Att. A at 13.
[26] Eversource Initial Comments, at 19; National Grid Initial Comments, at 14.
[27] DOER Initial Comments, at 9–13.
[28] *Id.*, at 26.

different, necessary way to cap CIP fees. CIP approval should depend on the per-kW cost of the upgrade itself. To avoid unnecessary ratepayer costs, developers should pay the cost of an upgrade allocated to DERs, and therefore no CIP should be built above the cost that developers can bear, even if that results in portions of the distribution grid with less DER interconnections. Several stakeholders made clear that there is a point at which the average kW cost of an upgrade will price out DG. National Grid notes that some portions of the system may simply be too expensive for CIPs[29] and IREC also anticipates that some upgrade costs will exceed what proposed DERs can afford.[30] To ensure that this developer cost barrier does not result in underutilized CIP investments, the Department should develop a total $/kW cost cap to protect ratepayers.

Given the number of nuanced issues associated with CIPs, the Department should consider CIP pricing alternatives as part of the DER Integration Roadmap process that the AGO outlined in its Initial Comments. Similarly, while the AGO's proposed DER Integration Roadmap offers a solution to many of the challenges that led to this proceeding, there should be an interim CIP process to address the immediate distribution system upgrades required to interconnect DERs because the DER Integration Roadmap requires a more lengthy process. Establishing an interim CIP process will require a transparent and collaborative process, which numerous stakeholders supported.[31] This interim CIP process will also need to evolve over time, because the AGO's DER Integration Roadmap will alter planning and interconnection processes, in turn modifying and informing the CIP process.

b. Hosting Capacity Map

The Department should prioritize accurate and detailed hosting capacity maps as a key mitigation strategy because they are a critical tool in effective system upgrade and DER location decision making. The EDCs currently publish hosting capacity maps based on built capacity without including planned capacity. Unitil believes that the maps should only depict the present available capacity, not planned capacity[32] while Eversource would be willing to work with the Department to develop a clear, consistent process with reasonable timelines for separate hosting capacity maps based on planned capacity.[33] National Grid described the option of creating a map layer for planned projects that can be selected onto its existing hosting capacity maps, but

[29] National Grid Initial Comments, at 15.
[30] IREC Initial Comments, at 7.
[31] National Grid suggested stakeholder engagement in distribution area studies for planning and for its dynamic curtailment pilot. National Grid Initial Comments at 22, 43. DOER advocated expanding stakeholder involvement in development and implementation of DER planning. DOER Initial Comments at 14; IREC "cannot overemphasize" the importance of a stakeholder engagement process for developing and approving the 10-year distribution planning assessment. IREC Initial Comments at 10; Eversource highlighted opportunities for stakeholder input in both DER forecasting and CIP selection, Eversource Initial Comments, Attachment Eversource IR-2, at 3; and the AGO's entire planning proposal is framed as two stakeholder processes with accompanying structure and detail.
[32] Unitil Initial Comments, at 9.
[33] Eversource Initial Comments, Att. Eversource IR-2.

cautioned that the process would require labor and time.[34] The AGO supports showing planned capacity on hosting capacity maps because it builds on the efforts already undertaken by the EDCs. National Grid's map layer, however, is likely to be the best (most efficient) mapping option.

Developing an additional hosting capacity mapping process will require that the Department and stakeholders scrutinize standardized EDC methodologies on an iterative basis and to evaluate mapping accuracy to the degree possible. Improving and iterating on hosting capacity analysis maps could easily be integrated into the AGO's DER Integration Roadmap because it will allow additional data streams and modeling approaches. In the near-term, the Department should direct the EDCs to update maps with detailed data more frequently than annually, which appears to be the current practice. As data quality and modeling practices improve, hosting capacity maps will be an important tool for efficiently locating DERs.

4. Additional Concerns Regarding EDC Incentives and Overarching Ratemaking Implications.

a. Potential for Timeline Milestone Incentives

Despite stakeholder agreement regarding additional process, the AGO is concerned that implementation of the DER Integration Roadmap concept may not be prioritized to the degree warranted. While the AGO appreciates the significant time and innovative thought processes that went into stakeholder comments, there are still concerns that the EDCs have a strong economic incentive to delay cost-effective solutions such as dynamic curtailment and improved hosting capacity maps. As noted by several stakeholders, mitigation strategies are very important, but while they are unavailable, the EDCs may overbuild the distribution grid. For this reason, the AGO encourages the Department to create regulatory milestones to incentivize the EDCs to enable mitigation strategies and evolve away from the interim CIP process in a timely manner.

The Department should create distribution system planning regulatory milestones to hold the EDCs accountable for timely implementation of the DER Integration Roadmap. For example, the Department could assign timelines to milestones and, if the EDCs do not meet them, the Department could restrict their CIP or other upgrade-related cost recovery. The Department should also address the overlap with and implications of performance-based ratemaking. Potential milestones could include:

- **Updated and transparent distribution system plans ("DSPs")**, including export-related distribution planning criteria and methods for identifying and allocating costs and benefits of imports and exports.
- **Dynamic curtailment functionality**, which will likely require tariff modifications to allow for participation. The operational benefits of dynamic curtailment will likely need to be integrated into the DSP planning process as a mitigation solution.

[34] National Grid Initial Comments, at 24.

- **Hosting capacity map requirements**, including data, update timing, and other conditions.

The milestones above are simply examples provided with the understanding that additional process development is necessary before determining whether milestones are appropriate, and—if they are—which milestones would effectively incentivize EDCs. These decisions could be made coincident with the Department's first CIP approval process.

b. Overarching Ratemaking Concerns

Another important outcome that could be used as a distribution planning milestone is the eventual integration of CIPs into multi-year rate plans, as DOER suggested in initial comments.[35] This outcome is important because a CIP reconciling mechanism, as with many investments, will erode cost containment incentives for the EDCs and conflict with the intent of multi-year rate plans. CIPs and their associated regulatory effects should be broadly contextualized. In that same vein, the AGO also endorses DOER's recommendation to coordinate DER planning and related investments across other proceedings such as grid modernization.

5. Conclusion

The AGO appreciates stakeholders' thoughtful comments on the Department's Straw Proposal and the opportunity to offer reply comments. The AGO respectfully requests that the Department adopt the recommendations in these reply comments as well as those that the AGO proposed in its Initial Comments.

Sincerely,

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[35] DOER Initial Comments, at 25.