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

December 23, 2020

RE: Distributed Energy Resource Planning and Assignment and Recovery of Costs for the Interconnection of Distributed Generation, D.P.U. 20-75

Dear Secretary Marini:

The Massachusetts Department of Energy Resources ("DOER") respectfully submits the following comments regarding distributed energy resource planning and recovery cost for the interconnection of distributed generation. The DOER submits these comments as the Massachusetts executive agency responsible for establishing and implementing the Commonwealth's energy policies and programs, M.G.L. c. 25A, § 6.

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

Sincerely,

s/Ben Dobbs

Ben Dobbs
Deputy General Counsel

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Inquiry by the Department of Public Utilities on its own Motion into Distributed Generation Interconnection	)	D.P.U. 20-75

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I. INTRODUCTION

On October 22, 2020, the Department of Public Utilities ("Department" or "DPU") issued an order opening an investigation into Distributed Energy Resource ("DER")[1] planning and assignment and recovery of distributed generation[2] ("DG") interconnection related upgrade costs ("Order"). In its Order, the Department proposes "a new distributed energy resource planning process with the purpose of assessing optimal solutions for the interconnection of DG facilities, taking a long-term planning perspective" and also "seeks comment on methods for the assignment and recovery of costs associated with the DG interconnection process and system modifications needed for interconnection."[3] The Department also posed a series of directed questions to stakeholders. Consistent with the schedule set out in the Order, the Department of Energy Resources ("DOER") now submits this comment along with responses to the Department's questions.

II. EXECUTIVE SUMMARY

DOER welcomes the Department's investigation into a long-term DER planning process, and the recovery and allocation of DG integration costs as key to advancing the Commonwealth's clean energy policies intended to meet greenhouse gas emission limits under the Global Warming

[1] For the purposes of this document, DOER adopts the DPU's definition of DER from its straw proposal. There, the Department states that, "[f]or purposes of this Straw Proposal our working definition of a distributed energy resource is a resource that: (1) is directly connected to the distribution system, or indirectly connected to the distribution system behind a customer's meter; and (2) generates energy, stores energy, or controls load. Under this definition, distributed energy resources include distributed generation (e.g., solar panels), energy storage systems, electric vehicles, and controllable loads (e.g., heating, ventilation, and air conditioning systems and electric water heaters)." D.P.U. 20-75, Att. A, p. 3, FN1 (2020).

[2] For the purposes of this document, DOER adopts the DPU's definition of DG from its straw proposal. There, the Department states "[f]or the purposes of this Order and the attached Straw Proposal, the Department intends the term DG to refer to any type of facility that must submit an application under a Distribution Company's DG Interconnection Tariff, regardless of whether it actually generates electricity (e.g., energy storage systems). D.P.U. 20-75 Order, p. 1, FN3.

[3] D.P.U. 20-75 Order, p. 2.

Solutions Act ("GWSA").[4] The Executive Office of Energy and Environmental Affairs ("EEA"), in coordination with DOER and the Department of Environmental Protection, is currently investigating the pathways to net-zero emissions for the 2050 Roadmap expected to be released in 2020 along with the 2030 Clean Energy and Climate Plan ("CECP") as required by the GWSA.[5] While there are multiple pathways to the net-zero emission limit, increased solar photovoltaics ("PV") integration and the electrification of the heating and transportation sectors will be key components. This increased reliance on the electric distribution system will require significant investment, and comprehensive and coordinated long-term distribution system planning will be crucial to identifying the most cost-effective upgrades that support consistent DER growth.

DOER sees great potential for this investigation to result in adoption of a DER planning process and a distribution upgrade cost recovery and cost allocation process that advances statewide efforts to meet these GWSA limits and clean energy targets. A successful outcome in this proceeding will produce a workable DER planning process where the electric distribution companies ("EDCs" or "Companies") sufficiently and cost-effectively plan for DG related distribution system upgrades at low cost while supporting adoption of DERs. DOER's vision for a successful outcome also includes a comprehensive cost recovery and allocation framework that guides DG developers with price signals to a least- or low-cost simplified pathway to interconnect, and reflects the reality that the beneficiaries of increasing solar and other DG development and the associated upgrades are more than just the interconnecting DG, but broadly include all ratepayers. Finally, the resulting process should cost-effectively facilitate DG interconnections and reduce barriers caused by capacity constraints and system studies.

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[4] G.L. c. 21N, § 3; St. 2008, c. 298.
[5] *See* "MA Decarbonization Roadmap," *available at* https://www.mass.gov/info-details/ma-decarbonization-roadmap.

While the Department's Order proposes many questions still to be answered regarding adoption of DER planning and cost allocation and recovery processes, in this comment DOER provides its support for the Department's straw proposal for DER planning and Capital Project Selection and Fees and offers recommendations for strengthening these proposals and the establishment of a Common System Modification Fee to support DER deployment most cost-effectively.

First, the Department should consider implementing a DER planning process that identifies necessary upgrades in advance of interconnection requests while identifying potential upgrade mitigation strategies that may avoid or defer certain distribution upgrades lowering overall interconnection costs and fees (see Subsection IV.A). As necessary upgrades can take multiple years from identification to operation, the planning process should commence expeditiously and utilize a long-term, multiyear timeframe to allow for the evaluation and possible implementation of these alternatives. The use of upgrade mitigation strategies such as shifting load and generation with energy storage, DG curtailment, grid-support inverter setpoints, and export limitations, has the potential to serve as lower cost alternatives to upgrades associated with integrating DG.

Second, the Department should consider the coordination of similar investments made in in other Department proceedings, including grid modernization and rate cases, in the DER planning process, and in the cost recovery of DG upgrades (see Subsection IV.B). The impact of electrification, DER adoption, and DG deployment are common considerations for the distribution system in these other proceedings and coordination ensures efficiency, transparency, and allows for the identification and consideration of multiple benefits from any single investment.

Third, the Department should consider expanding stakeholder involvement in the development and implementation of the DER planning process (see Subsection IV.C). It should provide the opportunity for stakeholder input in both defining the data to be used to set the planning criteria and the results of the planning process (*i.e.*, forecasts, anticipated capital investments, and areas identified as likely needing future investment) prior to pre-approval of any needed investments. Stakeholders, including clean energy industry representatives and policymakers, have insight into the expected market growth and development of DER. DOER can also provide input on how the Commonwealth's pathway to net-zero is expected to impact the distribution network. Providing transparency in this process will not only support the Companies' ability to accurately forecast but will allow policymakers to implement possible mitigating or supporting policies outside the Companies' control. Further, during the implementation phase of the DER planning process, the EDCs should identify barriers to implementation, if any, and timely solutions to those barriers with DOER input (see Subsection IV.D).

Fourth, DOER supports the Department's proposal to adopt a Capital Project Selection Process and Fee with modifications and recommends adoption of a Common System Modification Fee (see Subsections IV.E and F). Any fee and corresponding cost allocation structure that gets adopted must recognize the increasing difficulty of conclusively determining that an upgrade directly benefits an interconnecting DG facility, as anticipated by the Capital Project Investment Fee. DOER expects that the benefits from capital upgrades that accrue to ratepayers more generally, such as resilience and avoided cost of GWSA compliance benefits, will grow over time. The costs of upgrades should be allocated among DG and ratepayers according to the benefits they receive.

In addition, DOER offers several recommendations on the mechanics of these fees. Regarding the Capital Project Selection Fee structure, DOER offers several adjustments intended to reduce upgrade fees through upgrade mitigation measures while ensuring the fee provides the appropriate price signals both before and after an upgrade is implemented. Regarding the Common System Modification Fee, DOER recommends that the fee apply to all DG facilities not otherwise paying for DG interconnection upgrades unless certain conditions are met that limit the impact of DG on the distribution system. This would include all projects that do not require upgrades and therefore are not subject to the Capital Project Investment Fee. The Common System Modification Fee represents the shared impact that all DG has on the distribution system and should scale with the DG facility's export capability. The collected fees may then be applied towards necessary distribution system investments that are not eligible for recovery through the Capital Project Investment Fees. This may include smaller upgrades triggered by residential projects that limit localized deployment of DG.

Finally, DOER recommends that the Department explore the design and use of a performance metric and incentive to align the EDCs' business interests with the objective of cost-effective and timely hosting of electrification and substantial additional DG (see Subsection IV.G). A well-designed metric could include: (1) whether an EDC considered and used upgrade mitigation measures to achieve reduction in the cost of needed upgrades or achieved upgrade deferrals, or alternatively whether the EDC used a lower cost alternative to upgrade while still achieving integration of DG, and (2) whether integration of DG and associated installed upgrades or alternatives to upgrades advanced the Commonwealth's clean energy goals and GWSA compliance.

III. BACKGROUND

A year and a half after opening a predecessor docket, D.P.U. 19-55, the Department opened this D.P.U. 20-75 investigation expanding the scope of its inquiry regarding cost recovery and allocation for upgrades needed to integrate DG facilities to include long-term planning and cost recovery solutions.[6] In D.P.U. 19-55, the Department invited stakeholders to submit ***short-term*** proposals on separate cost allocations for DG resources for (1) small and (2) large DG customers. DOER submitted its proposal in 19-55 on February 28, 2020 ("DOER Proposal") and participated in a technical conference held on April 30, 2020. The DOER Proposal aimed to ensure equitable access to DG and its associated benefits, provide for continued integration of DG on a short-term basis, but recognize the need for longer-term distribution planning.[7]

Under the Department's proposal issued on October 22nd, 2020, the EDCs will "perform distribution system planning for the assessment of the interconnection and integration of Facilities..."[8] The Department states that, "[f]or purposes of the Straw Proposal, the distributed energy resource planning requirements apply only to Facilities subject to the DG Interconnection Tariff (including energy storage systems) and not to other distributed energy resources."[9] The DER planning process will identify Capital Investment Projects[10] needed for the interconnection and integration of DG Facilities.[11] These capital upgrades would be eligible for special ratemaking treatment with cost recovery through a reconciling charge.[12]

Under the Department's proposal, the EDCs will file Capital Investment Projects for Department review and pre-approval along with a cost of and kilowatt ("kW") capacity for the proposed Capital Investments.[13] In the pre-approval proceeding, the Department will establish a $/kW Capital Investment Fee. If approved, the EDC will allocate the fee to each Facility that

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[6] D.P.U. 20-75, Order, p. 4.
[7] The Department included the proposals submitted in D.P.U. 19-55 in the D.P.U. 20-75 investigation.
[8] Att. A, pp. 4-5.
[9] *Id.*, p. 5.
[10] *Id.*
[11] *Id.*
[12] Att. A, p. 6.
[13] *Id.*

subsequently benefits from the Capital Investment Project, excluding Facilities using the Simplified Process.[14] The enabled capacity costs would be initially funded by each EDC, and paid for by the EDC's customers through a reconciling charge with an annual rate cap applied.[15] "For a period of ten years from pre-approval, the Capital Investment Project Fees assessed to Facilities enabled by Department approved Capital Investment Projects will be credited to the Reconciling Charge to reduce (or possibly offset entirely) the costs borne by ratepayers at large."[16] If the full amount of capacity enabled by the Capital Investment Project were used by the DG facilities interconnecting within the ten-year period, ratepayers would see a "net zero" cost over the ten-year period.[17]

In its Order, the Department solicited comments on whether an additional fee may be beneficial to address Common System Modifications not covered by the Capital Investment Projects fee.[18] Although the Department did not put forth a specific proposal, it seeks to explore this option.[19]

IV. COMMENT

A. DOER Supports the Department's Proposed DER Planning Proposal and Supports the Inclusion and Consideration of Upgrade Mitigation Strategies

DOER supports a long-term DER planning, capital investment, and cost recovery process as essential to integration of DG, and more broadly, DER. Further, DOER shares the Department's goals of establishing a "system planning analysis to achieve the Commonwealth's clean energy and climate policy objectives."[20] To meet mandatory GWSA limits, the state must accelerate the

[14] *Id.*
[15] *Id.*, p. 7.
[16] *Id.*, p. 6.
[17] *Id.*, p. 6, FN5.
[18] D.P.U. 20-75, Order, pp. 6-7.
[19] *Id.*
[20] Att. A, p. 4.

electrification of the heating and transportation sectors, which will include deployment and integration of additional DG and DER such as electric vehicles ("EVs") and ground and air source heat pumps.[21] DOER also supports the Department's proposed ten-year rolling assessment of the distribution system to "identify system upgrades to accommodate forecast load growth and Facility interconnection" and "parallel upgrades that may be installed or expanded as part of a cost-effective solution that enables the interconnection of additional capacity beyond currently proposed Facilities."[22] Broadening the scope of this investigation to include long-term planning supports identification of the most cost-effective path to invest in a modern, bidirectional distribution system through the integration of DG and DER.[23]

However, the Department should clarify the scope of the DER planning process, and DOER would recommend that the process include analyses of all DERs in evaluating which upgrades are needed to integrate DG. DOER further recommends that the Department ensure that the DER planning process considers and captures the potentially significant value of upgrade mitigation strategies to defer or avoid distribution upgrades and identify more cost-effective alternatives.

However, the Department should clarify the scope of the DER planning process, and DOER would recommend that the process include analyses of all DERs in evaluating which

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[21] *See* DOER 2018 Comprehensive Energy Plan ("CEP") showing electrification of the transportation and heating sectors are fundamental to the Commonwealth's achievement of GHG emission limits *available at*: https://www.mass.gov/service-details/massachusetts-comprehensive-energy-plan-cep.

[22] Att. A, p. 4 (citations omitted).

[23] The Department's vision of a modern distribution system is captured in its grid modernization objectives: (1) "to optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing;" (2) to optimize system demand by facilitating consumer price-responsiveness and minimizing losses on the system; and (3) facilitate integration of DG and integrate these resources into planning. *Review of EDCs' Grid Modernization Plans*, D.P.U. 15-120, 15-121, 15-122, pp. 99-104 (May 2018).

upgrades or upgrade alternatives are needed to integrate DG.[24] DOER further recommends that the Department ensure that the DER planning process considers and captures the potentially significant value of upgrade mitigation measures to avoid or reduce the cost of needed distribution upgrades, achieve deferrals, and identify more cost-effective alternatives to upgrades. Ensuring that upgrade mitigation measures are considered when the EDCs evaluate during the DER planning process may help identify opportunities to avoid or reduce the cost of upgrades, achieve deferrals, and identify more cost-effective alternatives. The planning process should incorporate a broad range of upgrade mitigation measures intended to achieve infrastructure investment avoidance, available both in the near- and long-term planning horizons. Measures include both EDC and DG developer options for mitigating the grid impacts of DERs on the distribution system through both traditional upgrades and non-wires alternatives (i.e., shifting renewable generation onto peak or high-net demand periods, curtailment of excess generation, and providing limited export options as alternatives to capital investments for integrating DG). Upgrade mitigation measures could also include the usage of software such as DERMs which would enable export capacity limiting to reduce the impact of DG, and in the future, the use of EVs to lower grid impacts of DERs.

This approach to DER planning can reduce the risk that ratepayers will pay for stranded capacity resulting from overbuilt Capital Investment Projects identified early in the planning process.[25] Ensuring that the most cost-effective solution is identified should reduce the cost to integrate DG and support all DERs by keeping interconnection costs more affordable. Additionally, upgrade mitigation measures may result in deployment of technologies and practices

[24] As noted above in footnotes 1 and 2, DOER has adopted the Department's definition of DERs and DG for the purposes of this comment.
[25] Ratepayers must pay for the investments when the new capacity is not fully subscribed.

that have the co-benefit of advancing the Commonwealth's clean energy policies.[26] Circuits which have already been improved by Capital Investment Projects will continue to benefit from upgrade deferral and associated upgrade mitigation because those projects are intended to increase hosting capacity. Further, in some circumstances, upgrade mitigation measures may enable a higher total nameplate connection and associated energy (kWh) generation by DG on the same limited hosting capacity.[27]

For these reasons, the Department should include the following key elements in its DER planning for capital upgrades, which will help ensure the process enables upgrade mitigation and deferral opportunities:

- Forecasting that: (1) contains sufficient detail to consider both changes in load and demand in hourly granularity, and all seasons; and (2) include assumptions on locational growth of DERs (including but not limited to EVs, cold climate air source heat pumps, ground source heat pumps, and energy storage);[28]

- Evaluation of opportunities to serve new electric heating demand/EVs with DG given the significant expected growth in load related to electric heating and EV charging and the potential that load growth associated with EVs and air and ground source heat pumps may mitigate the impact of distributed generation;

- Evaluation of opportunities to shift renewable generation onto peak or high-net demand periods, or to curtail excess generation/provide limited export options as alternatives to capital investments for integrating DG; storage could potentially be used to achieve this, either utility- or third-party owned storage;

- Comprehensive planning that considers investments other than capital upgrades, which could lead to upgrade mitigation, which may be the subject of other proceedings. For instance, software solutions as alternatives to hardware solutions should be discussed, particularly when software solutions can result in substantial cost savings. EDC-operated Distributed Energy Resource Management System

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[26] Clean energy technologies would include storage or curtailment, and clean energy policies could include rate design and load management.

[27] For example, depending on the type of upgrade required, curtailment of DG on select hours of low load and high DG generation can increase both the amount of DG hosted on the circuit and therefore increase the total annual energy generation by DG on the circuit. Energy storage can function in a similar manner, except it shifts the production toward higher load hours, rather than curtailing the generation.

[28] *See supra* note 1, DOER adopted the DPU's definition of DER for the purposes of this comment.

("DERMS") and/or facility-managed curtailments may be considered as a cost-effective alternative to infrastructure upgrades; and[29]

- Adoption of grid-support inverter set points established in IEEE 1547-2018, and consideration of those set points in forecast criteria to increase hosting capacity before triggering substantial upgrades.[30]

B. The Department Should Consider Transparency and Coordination Between the Long-Term DER Planning Processes and Related DPU Proceedings

As part of their ongoing business as a regulated utility, the EDCs evaluate capital and other distribution system investment and programmatic options and seek recovery in multiple regulatory proceedings presided over by the Department. Clean energy policies supporting the growth of electrification, DER, and DG all impact the distribution system and may require investments in other proceedings. Coordination not only in the planning process but also cost recovery ensures efficiency, transparency, and allows for the identification and consideration of multiple benefits from any single investment. Expanding the DER planning in this proceeding to include the timelines, investments, proceedings, and programs that impact the distribution system (such as grid modernization, demand response, and energy efficiency) produces several benefits that include:

- Providing transparency and enabling meaningful stakeholder involvement in the EDCs' assessment of the full range of costs and benefits for investments considered across various proceedings (*i.e.*, grid modernization proceedings, and rate cases); and

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[29] DOER suggests below that the Department consider adding DERMS to the potential list of Capital Investment Projects in its response to Department Question 1 and its subparts.

[30] The NREL Report "Smart Inverter Utility Experience in Hawaii" summarizes how grid-support settings on inverter-based DG has enabled integration of very high penetrations of solar DG onto the distribution system, *available at* https://www.nrel.gov/docs/fy19osti/74091.pdf. Similarly, National Grid pilots in Massachusetts are investigating grid-support settings on inverters to mitigate distribution and transmission upgrade requirements to increase hosting capacity of DG, *available at* https://drive.google.com/file/d/1xhlWcnXPTQAjjRvyA8R7jRrf7ywTsWXR/view?usp=sharing. The EDC process for establishing inverter VAR settings for large (>1MW) DG is in process (IEEE 1547-2018 adoption under consideration by TSRG and included as a topic in 19-55). Completion of this process is expected to result in substantial increase in enabled hosting capacity prior to the need for certain system upgrades, such as voltage support.

- Helping to ensure that DER planning and other processes are coordinated and ensuring that goals set out in relevant proceedings (*i.e.,* PBR PIMs, grid modernization goals, and distribution system planning goals) are aligned, promoting administrative efficiency in review of EDCs' proposals.

For these reasons, the Department should consider modifying the DER planning process to ensure that it demonstrates coordination and transparency between respective long-term planning processes and relevant proceedings.

C. The Department Should Expand Stakeholder Input to Ensure Stakeholders Provide Input on the Planning Assumptions and Outcomes

In its straw proposal, the Department states that it "will establish planning criteria, informed by stakeholders, for the distribution system assessment."[31] DOER supports the Department's proposal to involve stakeholders in the proposed DER planning process and recommends expanding stakeholder input to include input on the planning process results prior to pre-approval of any upgrades. Soliciting stakeholder input on planning results prior to pre-approval of any needed investments allows access to outcomes, promotes transparency, and assists in policymaking.

Inclusion of stakeholders in system planning (*i.e.,* forecasting load and generation analysis) both at the state and the regional transmission operator system-level improves stakeholder access to data and insight into policy and market development opportunities.[32] Involvement of policy

[31] Att. A, pp. 4-5.

[32] Instructive examples for provision of stakeholder input into system planning include ISO New England's various forecast working groups. According to ISO-NE's website, the Distributed Generation Forecast Working Group (DGFWG) "is a regional forum for interested parties, including state policymakers, distributed generation (DG) program administrators, and distribution companies, to provide input on ISO New England's long-term DG forecast." https://www.iso-ne.com/committees/planning/distributed-generation/?eventId=134451. Another example is the Hawaii Public Utility Commission's evolving process for Integrated Grid Planning ("IGP") which maintains a strong emphasis on the role of stakeholder engagement in IGP. Their IGP docket 2018-0165 includes a Stakeholder

makers and other stakeholders also helps to ensure that planning criteria and key planning assumptions (*i.e.*, which areas are experiencing comparatively high load growth) align with state policy development and forecasts, and DG market conditions. Moreover, input from developers and other stakeholders on technology type, size, and location of DG is important to align upgrades with DG market incentives and opportunities.[33]

Results from the EDC planning process that will benefit from stakeholder input include: the EDCs' preliminary list of anticipated areas which need upgrades and the EDCs' assessment of opportunities to mitigate or defer current or future investments with energy storage, load management, or grid operation technologies. The stakeholder input process should also include discussion of an EDC-generated "stress test" of scenarios designed to evaluate risks involved with preliminary investment decisions (*i.e.*, size, location, etc.).

DOER's input into the planning criteria, the forecast assumptions, and the DER planning process outcomes will include providing planning assumptions that are consistent with the Commonwealth's pathway to net-zero emissions by 2050. EEA expects to release the 2050 Roadmap in 2020 along with the 2030 CECP. As part of the investigation into possible pathways, EEA has undertaken modeling and analyses that will provide high-level estimates of necessary amounts of clean energy generation and electrification in certain years for Massachusetts on a system-wide basis. By participating as a stakeholder in a transparent process to develop inputs,

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Council; *see* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/stakeholder-council and Working Groups; *see* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups; which recently resulted in stakeholder access to the Utility's RESOLVE models used for forecasts. Stakeholder involvement in DG hosting in Hawaii also extends to their DER docket 2019-0323, Community-Based Renewable Energy docket 2015-0389, Performance Based Regulation docket 2018-0088, and electrification of transportation docket 2018-0135.

[33] *See e.g.*, https://www.iso-ne.com/committees/planning/distributed-generation/?eventId=134451 (ISO New England notes that the " role [of its DGFWG] includes gathering information on planned DG projects (including technology type, size, and interconnection requirements), and examining challenges and solutions associated with large-scale DG integration in New England."

DOER can help the EDCs by providing guidance on how to leverage and integrate any data from the CECP and Roadmap analysis into the DER planning process as appropriate.

D. Barriers and Solutions to Implementation of a DER Planning Process Should be Identified Early to Prevent Delays in Implementation

DOER expects that this distribution planning process will require the EDCs to learn from early planning processes and refine their modeling and planning to become more detailed, both in timescale and location. Barriers that arise during early implementation of a new DER planning process should be resolved to avoid implementation delays. As the state's agency charged with implementing clean energy policy, DOER understands and implements the energy policy goals of and programs in the state, and that knowledge puts DOER in a position to problem solve with the EDCs on planning barriers with respect to those policies and programs. Further, if helpful, DOER would be available to facilitate a planning process that utilizes the structure of the ISO-NE's various forecast working groups, for instance.[34] DOER has played a facilitation role in stakeholder development of consensus amendments to the DG interconnection tariffs in DPU 19-55 relating to storage. Should challenges arise in the implementation phase, DOER would be open to assisting as a facilitator again.

E. DOER Supports the Department's Capital Project Investment Selection and Fee

Under the Department's proposal, the EDCs will use the DER planning process to identify Capital Investment Projects[35] eligible for special ratemaking treatment with cost recovery through a reconciling charge.[36] EDCs will file Capital Investment Projects for Department review and pre-

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[34] For example, third parties and academic institutions may be a resource to test new modeling or planning strategies.

[35] Capital Investment Projects may include but are not limited to: (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.

[36] Att. A, p. 5.

approval along with a cost of and kilowatt ("kW") capacity for the proposed Capital Project Investments.[37] "As part of the pre-approval process for the Reconciling Charge, a Distribution Company would identify the cost of and kilowatt ("kW") capacity enabled by proposed Capital Investment Projects. Based on this information, the Department would then establish a $/kW Capital Investment Project Fee for the Distribution Company to allocate to each Facility that subsequently benefits from the Capital Investment Project (Att. B-5 at 19)."[38] Costs would be initially funded by each EDC, then paid for by the EDC's customers through a reconciling charge with an annual rate cap applied.[39] Amounts recovered through the Capital Investment Fee will be credited to the EDC customers for up to a ten-year period.[40] If the full amount of capacity enabled by the Capital Investment Project were used by the DG facilities interconnecting within the ten-year period, ratepayers would see a net zero cost over the ten-year period.[41]

DOER supports the Department's Capital Investment Project Selection and Fee and recommends that the Department consider several options for strengthening its proposal, as outlined below:

- **Incentivize upgrade mitigation measures and deferrals through the pre-approval process:** Require the EDCs to include evaluation of upgrade mitigation and deferral options in the pre-approval process, and require each EDC to demonstrate that the upgrade is needed because upgrade mitigation or deferral was not possible prior to pre-approval as a reasonably implementable process improvement;

- **Reduce resulting Capital Project Investment Fees:** Ensure the fee structure: (1) recognizes existing headroom on the circuit at the time of preauthorization and includes that headroom in the calculation of kW hosting capacity for the $/kW fee calculation and,

[37] *Id.*, p. 6.
[38] *Id.*
[39] The reconciling charge is established in a proceeding that is separate to the pre-approval proceeding. Att. A, p. 5., FN3.
[40] Att. A, p. 6.
[41] *Id.* There is a risk that the enabled capacity would not be fully subscribed and that ratepayers would pay a portion of the investment.

(2) applies the fee to DG interconnections following the preauthorization of upgrades but before the actual upgrade is complete; and

- **Incentivize mitigation and deferral:** The Department's Capital Project Investment Fee proposal does not collect fees from interconnecting DG before the Capital Investment Project occurs. As proposed, EDCs may seek pre-approval for and build Capital Investment Projects as early as practicable to maximize the amount of DG which pays the Capital Investment Project Fee, reducing the $/kW fee, and increasing the likelihood of complete collection from interconnecting customers.[42] A challenge with this design is it incentivizes early action and early investment in infrastructure, while disincentivizing an emphasis on mitigation and deferral of upgrades.

Adoption of these measures should help promote DG installations by ensuring lower fees and upgrade costs while minimizing ratepayer exposure to capital investment costs that flow through a reconciliation charge. Resulting lower $/kW fees are a critical element to sending proper price signals. Keeping fees on the lower end is important because if the Capital Project Investment Fee is too high, it will send an undesirable price signal to develop elsewhere instead of developing in the precise location where the upgrade was made. The goal is to ensure the fees are reasonable so that DG interconnects at the location of where the Capital Investment Project upgrade was made.

Further, deferral is particularly valuable when considering the Department's proposed Capital Investment Project Fee, as many of the upgrade technologies are rapidly improving and declining in cost. For example, battery costs declined 87% last decade, and are likely to continue the decline for at least the next decade.[43] Deferring an upgrade, even by just a few years, can

[42] The earlier an upgrade is made, the more existing headroom which can be included in the $/kW fee, and the higher the number of kW the lower the resulting fee. A low $/kW fee is beneficial from an EDC perspective because it increases the attractiveness for developing in that area, increasing the likelihood of full recovery of the upgrade cost from projects. Also, the earlier an upgrade, the higher the likelihood that there is enough development intent in the area to build and support full cost recovery. If an upgrade is delayed, the EDC may have a lower confidence that sufficient development demand exists in the area. As a result, EDCs may seek pre-approval as early as practicable in order to de-risk the upgrade. If the EDC is instead able to collect a fee from customers in the interim (i.e., a supplemental Common System Modification Fee), then EDCs may have increased confidence in cost recovery from projects while deferring or mitigating upgrades.

[43] *See* Bloomberg New Energy Finance; ***available at*** https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/. Solar PV has followed similarly aggressive cost declines, and if PV declines continue then the opportunity cost of curtailment similarly declines in the future.

substantially change what technology is selected for a capital investment, and how much hosting capacity can be increased per dollar.[44]

F. The Department Should Establish a Common System Modification Fee That Reflects the Impact of DG on the Distribution System

As more fully explained below in the DOER's responses to the Department's Question 2 and its subparts, the Department should establish a Common System Modifications Fee in addition to the Capital Investment Project Fee. Here, the Department is soliciting comments on whether an additional fee may be beneficial to address Common System Modifications not covered by the Capital Investment Projects Fee.[45] Although the Department did not put forth a specific proposal, it seeks to explore this option.[46]

The Department should consider DOER's original proposal submitted in D.P.U. 19-55, as elaborated on or amended in the responses to the Department's Question 2 below, as an example of how such fees should work for small, medium, and large customers. Common System Modification Fees should be based on the DG Facility's impact to the grid by considering the DG facilities' export-limiting capacities. Collected amounts should be applied towards distribution system investments needed to integrate DG, but not eligible for Capital Project Investment Fees. Further, in recognition that there may be areas of the distribution system that could provide ratepayer benefits from DERs, there could be fee exemptions to help facilitate continued growth.

[44] Similar to the storage cost declines, within the 10-year planning horizon EDC deployment of DERMS may substantially increase hosting capacity on existing infrastructure. A deferral from a pre-DERMS environment to a post-DERMS environment can represent a substantial increase in hosting capacity at little-to-no cost. The adoption of grid-support functions in inverters represents another potential step-change in hosting capacity without requiring a physical upgrade, similarly highlighting the potential non-linear cost-benefits of deferrals.
[45] Att. A, p. 9.
[46] *Id.*

Alternatively, the Department could consider simplification of a fee structure that combines the Capital Project Investment Fee and the Common System Modification Fee, which may accommodate circumstances where interconnecting DG benefits from a portion of the upgrades, while there are other generalized benefits provided by upgrades. Under this alternative approach, costs of upgrades could be allocated among DG and ratepayers according to the benefits they receive. This may be an attractive approach to consider, because as the planning horizon is lengthened it may become more difficult to conclusively determine that an upgrade directly benefits an interconnecting DG unit, as anticipated by the Capital Project Investment Fee. DOER expects that the benefits from capital upgrades that accrue to ratepayers more generally, such as resilience and avoided cost of GWSA compliance benefits, will grow over time.

G. DOER Supports the Design and Use of a Metric that Incentivizes the Mitigation of DG Upgrades and DER Deployment to Support Clean Energy Goals and GWSA Compliance

In this proceeding, the Department should explore the design and use of a performance metric that incentivizes the identification and implementation of the most cost-effective solution for DG and DER integration. DOER recognizes the complexity of DER planning and evaluating mitigation strategies. Consequently, it may be prudent for the EDCs to receive a financial incentive for selecting the solution that is the least cost for ratepayers particularly if upgrade mitigation measures or deferring a traditional upgrade may create disincentives for the EDCs.

A well-designed metric could include (1) whether an EDC considered and used upgrade mitigation to achieve reduction in the cost of needed upgrades, or achieved upgrade deferrals, or alternatively whether the EDC used a lower cost alternative to an upgrade, all while still integrating DG, and (2) whether installed upgrades advanced the Commonwealth's clean energy goals and GWSA compliance. The metric could be established as a standalone metric, or as a performance incentive mechanism to be proposed by an EDC as part of a performance-based ratemaking ("PBR") proposal. Establishing metrics, even at a high level in this proceeding, may enable the establishment of more detailed metrics within a PBR in the future.

V. DOER'S RESPONSES TO THE DEPARTMENT'S QUESTIONS

For ease of the Department's review, the DOER has included the Department's questions, and its responses below. DOER's responses refer to the DOER's prior proposal submitted in D.P.U. 19-55. To provide the reader context, DOER provides this summary of its prior proposal.

DOER recommended the use of a cost-based interconnection fee structure for DG facilities that would be fairly and equitably applied based on the size of a DG facility.[47] An interconnection fee would be assessed to all residential DG customers using the Simplified Process under the DG Interconnection Tariff, as well as medium and large DG customer interconnections that do not require system modifications under the Expedited and Standard process.[48] Cost causation principles would continue to apply to medium and large DG facilities that require system modifications to preserve price signals.[49] Collected fees would be used to offset the cost of system modifications caused by the interconnection of residential DG facilities and for a portion of upgrade costs caused by the interconnection of medium and large DG facilities.[50] If upgrade costs exceed the amount collected through fees, the EDCs could recover the remaining upgrade costs from ratepayers.[51] A mechanism may be included to cap rate recovery and adjust the level of the fee over time to reassess ratepayer costs.[52]

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[47] D.P.U. 19-55, DOER proposal, p. 2.
[48] *Id.*
[49] *Id.*
[50] *Id.*
[51] *Id.*
[52] *Id.*

(1) Refer to Section II, Distributed Energy Resource Planning Requirements. Please discuss the effectiveness of this proposal, specifically:

a. The Department has identified the following list as solutions that address potential system needs. If you disagree with any solution included on this list, please explain why. Please identify and explain any additional solutions.

i. Technologies for Voltage Control on the Distribution System
ii. Distribution Bulk Transformer Addition or Replacement
iii. New Bulk Station

Should the Department adopt a pre-specified list of solutions, DOER supports the list of upgrades proposed by the Department and recommends that the Department consider additional categories for Capital Investment Upgrade as provided below:[53]

- reconductoring and related modifications;[54]
- expanding three-phase service;
- system reconfiguration, such as changing which customers are served by a circuit;
- increased distribution primary voltage to increase capacity, *i.e.*, reconfigure an area from 13.8kV to 34.5kV or have both 13.8kV and 34.5kV on a single right of way;[55]
- EDC-owned energy storage, where the technology may address potential system needs such as mitigation of integration impacts on a circuit; and
- EDC-operated DERMS solutions to mitigate the need for infrastructure upgrades.

b. Should transmission studies and costs be included in proactive system planning as it relates to interconnection? Explain your reasoning.

Yes. The Department should consider requiring the EDCs to include the cost of transmission studies and upgrades incurred by the EDCs in proactive system planning as well as

[53] The Department should consider categorization of investments based on the problem solved, such as: load flow constraints, power quality, and protective functions associated with hosting additional DG. For example, distribution bulk transformer additions or replacement and new bulk station appears to resolve load flow constraints and should therefore be categorized as a load flow constraint solution. This may simplify comparisons between differing technologies which solve for the same problem, enabling direct cost comparison of new bulk station versus energy storage in solving for load flow constraints.
[54] As outlined in Att. A, p. 5, FN2.
[55] By operating at a higher voltage, the lines have a substantially higher power-carrying capacity and may provide a substantial increase in capacity for a given Capital Investment Project.

estimates of these costs in upgrade pre-approval proceedings. Exclusion of such costs could result in an EDC's selection of a Capital Investment Project with a relatively high $/kW fee, rather than lower cost alternatives. For example, including the likely transmission costs associated with needed distribution upgrades is important to determine whether the distribution upgrades or other options (*i.e.*, EDC-owned energy storage) are the lowest cost option. Selecting the lower cost option should result in a lower $/kW Capital Project Investment Fee.

If, alternatively, the Department excludes transmission costs and timelines from consideration in Capital Investment Projects, EDC-owned storage and utilization of grid-support functions in inverters may enable near term separation of distribution planning from transmission planning simplifying the planning and cost allocation process. Note that DOER anticipates closer coordination between state policy and transmission planning in the medium to longer term future.[56]

c. Should the distribution system assessment identify projects that provide broader benefits beyond enabling incremental DG capacity? If so, explain:

Yes. Generally, distribution upgrades can provide significant and broad benefits for all ratepayers, regardless of whether they enable incremental DG capability. These benefits include increasing reliability and resilience. In addition, enabling renewable or clean energy on the distribution system or behind the meter can help decrease greenhouse emissions across the system. Further, if upgrading the distribution system enables faster adoption of electric vehicles, the benefits extend to reducing emissions from the transportation sector. Further, an assessment that identifies upgrades to equipment approaching the end of its useful life as supplemental to a DG-related upgrade alone could provide the lowest cost solution to both DG and non-DG related upgrades.

[56] New England States Vision Statement; http://nescoe.com/resource-center/vision-stmt-oct2020/#:~:text=Given%20the%20intersection%20of%20State,sustained%20investment%20in%20clean%20energy (October 16, 2020).

i. what benefits should be considered

The Department could consider a wide range of benefits beyond enabling incremental DG capacity, including: replacement of equipment approaching the end of its useful life, enhanced resilience, avoided GWSA compliance costs, enabling economic development (*i.e.*, 3-phase expansion),[57] coordinated investments with upgrades to support strategic electrification *(i.e.*, large public EV charging stations), peak shaving *(i.e.*, storage that absorbs energy off peak thus opening DG hosting capacity, and then discharges later coincident with peak), adaptability to accommodate future technology innovation and new load growth and patterns, scalability and replicability to enable transition away from special ratemaking treatment, controllability and future-proof such that investments can leverage future system automation/controls to be deployed by EDCs, and potentially other metrics as outlined by organizations such as the Grid Modernization Laboratory Consortium ("GMLC") and the GridWorks.[58]

ii. how these benefits should be quantified

At this stage in the process, DOER does not have a quantification proposal, however, the resources noted above (GMLC and GridWorks) have dedicated substantial efforts toward establishing metric quantification of grid modernization investments.[59] DOER supports spending

[57] Parts of the state have single-phase distribution service, and those areas cannot attract certain commercial businesses which have higher power demands. DG Facilities also often require access to 3-phase service. Expanding 3-phase service to areas which currently only have single-phase thus opens access to both new DG as well as new businesses to locate in the area. DOER has awarded a grant in the past to assist with expanding 3-phase service to demonstrate the co-benefit of enabling DG and enabling economic development.

[58] *See* https://gmlc.doe.gov/projects/1.1; *see also* https://gridworks.org/wp-content/uploads/2015/06/More-Than-Smart-Report-by-GTLG-and-Caltech-08.11.14.pdf.

[59] *See* https://gmlc.doe.gov/projects. Some projects focused specifically on developing appropriate metrics and quantification techniques, including "Grid Modernization: Metrics Analysis," which includes Reliability, Resilience, Flexibility, Sustainability, Affordability, Security metrics, methods to baseline, and quantification. https://gmlc.doe.gov/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf. The GMLC provides periodic updates on these projects, and updates on the Metrics can be found, on the right-hand-side under "Related Resources" → "Reports" at https://gmlc.doe.gov/projects/1.1

a portion of this investigation on developing quantification methods for such benefits. A starting place, beyond the GMLC, may include review of metrics and associated quantification techniques proposed in the Grid Modernization Dockets[60] and in PBR rate cases.[61] Within these dockets, stakeholders such as DOER provided comments on quantifiable metrics aligned with the benefits identified above.[62]

iii. the appropriate method for cost assignment and recovery.

Cost Recovery: Ideally, the Department's DER planning would transition to standard utility practice within a PBR and not require separate and special ratemaking treatment in the future. However, DOER supports the Department's proposal to adopt a special ratemaking treatment option with pre-approval for investments needed to integrate DG and DERs as it may help incentivize the EDCs to make needed investments. In general, DOER supports a cost recovery approach that includes built-in ratepayer protections, including but not limited to a cost recovery cap, a focus on optimizing demand (specifically reducing demand coincident with periods of peak demand, and increasing demand coincident with periods of low demand) and mitigation, and review mechanisms with strong oversight, such as a prudence review.

Cost Assignment: The appropriate method for cost assignment depends on the scope of broader benefits provided, and the degree to which a project extends beyond enabling incremental DG capacity. Where possible, the Capital Investment Project Fee should seek only to recover the portion of a project which is directly attributable to enabling the increase in hosting DG capacity. If an upgrade provides benefits to ratepayers more generally, the costs should be assigned to ratepayers commensurate with the level of benefits they receive from the upgrade. This could be

[60] *See* D.P.U. 15-120, 15-121, and 15-122.
[61] *See* D.P.U. 17-05 and 18-150.
[62] Comments included GMLC references.

accomplished through a Common System Modification Fee, or potentially an alternative fee that may be based on various types of upgrades associated with the Capital Project Investment and the Common System Modification, as noted in Section IV.F. above.

d. Should there be a cap on the dollar-per-kW billed to each Facility that benefits from the Capital Investment Project? If so, please explain how the cap should be determined.

Given the nature of the pre-approval for capital investments, and the cost review that entails, it is unclear as to whether a cap is needed. As explained in Sections IV, A and G above, the distribution planning process should maximize upgrade mitigation and deferrals to help reduce the cost of hosting DG and DER, and a metric should be explored to reinforce this goal. The higher the $/kW charge, the higher the likelihood that the specific DG sponsors would prefer to locate elsewhere, leaving any upgrades made to be recovered through general rate payers. This is because the high $/kW charge provides a high price-signal to DG sponsors to avoid developing in that area. This could create an unintended adverse reaction unless the process coordinates the distribution upgrades with specific DG sponsors' activities. Otherwise, DG projects are likely to develop away from newly created hosting capability.

Further, as proposed, there may be potential for gaming of the price signal. For example, a large Capital Investment Project moves forward and opens substantial hosting capacity but at a relatively high $/kW. Developers see the high $/kW fee and avoid developing within that area for 10 years since it is cheaper to develop elsewhere. In year 9.5, developers prepare substantial investments in the area and move forward with applications in year 10.1. At this point, the entire Capital Investment Project is recovered from ratepayers since there was a price signal sending development elsewhere, and a substantial headroom for DG opens with no upgrade costs to developers following the 10th year. A process must be developed to avoid these unintended circumstances.

(2) Refer to Section III, Common System Modification Fees. Please discuss the effectiveness of this proposal, specifically:

a. Simplified Facilities

i. 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 Department should establish a fee for Simplified Facilities[63] as residential customers do not have the opportunity to change locations responsive to an interconnection cost price signal. As noted in DOER's original proposal in D.P.U. 19-55,[64] the DPU should consider waiving the fee for locations where there are clear benefits of continued DG growth. DOER provided a proposed fee that is consistent with the Common System Modification Fee in its original proposal submitted in D.P.U. 19-55.[65] DOER recommends a fee similar to its original proposal, that is variable based on the relative impact of the facility on the distribution system, and substantially decreased for resources with minimal or no exports.

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

At a high level, the Common System Modification Fee could be applied to replacing service transformers for simplified projects where required, or other costly circuit level upgrades caused by the aggregate impacts of small residential solar on the distribution system. DOER is aware of occurrences where a shared pole-mount transformer is identified as needing replacement

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[63] Simplified Facilities refers to facilities that interconnect to an EDC's distribution system though the Simplified Process track provided in each EDC's respective DG interconnection tariffs.
[64] DOER Proposal Section III.G
[65] DOER Proposal consistency included: applicability to Simplified, Expedited, and Standard projects, fee based on relative impact of the facility on the distribution system, and recognition of additional benefits upgrades have to customers.

for a residential solar project to proceed. The cost of this upgrade is high enough that it can prevent the solar project from proceeding.[66] The Common System Modification Fees could be applied to pay for these types of upgrades that might otherwise become barriers to interconnections for Simplified Facilities. This is consistent with the proposal DOER put forth in D.P.U. 19-55.[67] As DOER suggested in D.P.U. 19-55, if all interconnecting customers under the Simplified pathway paid a relatively small fee, transformer replacements could be kept out of individual simplified interconnection upgrade costs ensuring that this type of upgrade does not disrupt residential adoption of solar PV.[68] DOER proposes that the Department establish the Common System Modification Fee to accomplish this end.

iii. How would such a fee interact with the system planning process described in Section II? 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?

<u>Fees Applicable to Simplified Process Interconnections:</u> As noted in the response above, the fee would be applicable to transformer replacements associated with residential interconnections. That would be on a separate track than the system planning.

<u>Fees Applicable to Expedited/Standard Process Interconnections:</u> Funds could readily be used to offset the costs of Capital Investment Projects to reduce ratepayer exposure to under-recovered Capital Investment Projects.

b. Expedited and Standard Facilities

i. Is a minimum Common System Modification Fee appropriate?

[66] *See* EDC December 4, 2020 filings into this docket, specifically Simplified project maximum costs identified vs. maximum costs which proceeded with interconnection.
[67] DOER's Proposal noted this specific application of funds under Section II and Section III.D.
[68] D.P.U. 19-55, DOER Proposal, Section II, p.2.

The Department should establish a minimum Common System Modification Fee for Expedited and Standard Facilities that is based on the DG Facility's impact to the grid. DOER recommends a fee structure based on the DOER Proposal for medium and large customers. DOER's proposed structure varied according to project size, incorporating both total nameplate size and size of export capability. While DOER's Proposal did not include a "minimum" fee level, the "nameplate size" aspect of DOER's Proposal would effectively set a minimum $/kW nameplate that even a non-exporting facility would trigger. Since a DG Facility's export capability is a substantial driver of impact to the grid, export capability should be the primary driver of the level of Common System Modification Fee. Under DOER's proposed framework, the Common System Modification Fee $/kW of nameplate would serve as the minimum fee for all interconnecting facilities, which should be relatively low (20% in DOER's Proposal) compared to the Common System Modification Fee which would apply to a facility which may export its entire nameplate capacity.

1. Provide a proposed method for determining such a fee.

Section III of the DOER Proposal includes a proposed method for determining a fee.[69] In summary, DOER recommends that the fee be based on the relative impact the facility on the distribution system. DOER recommends that the fee be levelized by both the proposed DG facility's nameplate capacity in kilowatts ("kW") as well as its export capacity in kW. The fee is weighted to ensure that limiting export capacity enables a substantial reduction in interconnection fees, driving customers to self-consume onsite DG generation. Weighing export capacity in this manner is appropriate because a non-export customer only uses hosting capacity associated with their own onsite load, and the project is not reliant on using shared hosting capacity of the circuit.

[69] D.P.U. 19-55, Department of Energy Resources' comments on remaining issues related to ESS interconnection, Section III, pp. 4-7.

A non-export customer thus pays substantially less toward the shared upgrades required to increase shared hosting capacity. While a non-exporting customer can substantially reduce their interconnection fee, the nameplate capacity portion of the equation ensures that non-exporting DG still contributes to system upgrade requirements, which is appropriate to reflect that exporting facilities exist on the grid today. DOER recommended a cost-basis for setting the fee level.

2. Explain why the proposed fee levels are appropriate considering the level of investment required to support the types of investments the fee is intended to cover.

DOER's Proposal only included a singular fee structure and can fit into the Department's proposal as replacement for the Common System Modification Fee. DOER's Proposal previously recommended the fee be cost-based, to be determined on data EDCs would provide to establish past average $/kW of upgrade costs. DOER still recommends the fee be cost-based. In the Department's proposal, the cost basis could likely be adjusted to account for the separate Capital Investment Project Fee. Since the Capital Investment Project Fee will be structured to recover the cost of distinct upgrades to increase hosting capacity, the cost basis for establishing the Common System Modification Fee could be established to only recover the average costs of upgrades not included in Capital Investment Projects.

3. Explain how the proposed fee establishes clear price signals, provides cost certainty, and limits ratepayer costs.

<u>Clear Price Signals:</u> As explained in the DOER Proposal, DOER's proposed fee would seek to establish clear price signals as it is designed to reflect the relative impact of the DG facility on the distribution system.[70] For example, a non-exporting facility should have a substantially lower fee than a facility which may export the entirety of its output because a non-exporting facility is using

[70] *Id.* Section III of the DOER Proposal considers establishing price signals in fees, cost certainty, and limiting risk of ratepayer recovery of upgrades.

hosting capacity associated with its own load. The DOER Proposal assumes that building DG that corresponds to load consumption reduces the need for distribution upgrades, and thus, if DGs co-locate with load, their cost burden to interconnect could be lower from a distribution upgrade perspective. Application of the Common System Modification Fee to Expedited and Standard projects which are not subject to a Capital Investment Project Fee also provides a clear price signal which supplements the Capital Investment Project Fee. As noted above, a high Capital Investment Project Fee may result in sending a price signal to develop elsewhere. A Common System Modification Fee which applies to all areas may help reduce the adverse impact of charging certain DG or DER project sponsors.

<u>Cost Certainty</u>: The DOER Proposal provides cost certainty to simplified projects because the interconnection cost is knowable at the time of DG facility design. This is an improvement over the status quo, where costs are not known until after DG facility design and subsequent interconnection study is complete. The proposal also provides cost certainty in that it would apply across an EDC's territory. This simplifies cost certainty and understanding interconnection costs for DG developers of small projects.

<u>Limit Ratepayer Costs:</u> DOER proposes that Common System Modification Fees which are not applied to upgrades for small behind the meter ("BTM") facilities could be applied to Capital Investment Projects which are under-recovered by Capital Investment Fees following their 10th year. In this way, the Common System Modification Fee could mitigate risk of ratepayer costs associated with the Department's Capital Investment Project proposal. The DOER Proposal includes additional details responsive to this request.[71]

[71] *Id.* Section III of DOER's proposal suggested the cost-basis for the fee could actually be above 100% of the average of past actual incurred costs to reflect the expectation of increasing costs in the future as well as reduce the risk of recovery from ratepayers.

4. Explain how such a fee would interact with the distribution system planning process described in Section II.

The fee would interact with the distribution planning, with fee collection, and with fee usage. The DER planning process described in Section II of the Department's straw proposal largely seeks to address area-wide hosting capacity constraints.[72] The desired process will result in large, singular upgrades which require pre-approval. As proposed by the DOER Proposal, the Common System Modification Fee would be applied to upgrades required to enable customers with existing onsite load to interconnect new distributed generation.

Individual BTM projects often cannot be forecasted and pre-empted with upgrades in the same way that the bulk system can be. As such, DOER recommends that the Common System Modification Fee be pre-approved at a higher level, such as pre-approving the use toward service transformer replacements, and for 3V0 improvements to substations which are not otherwise identified for upgrades in the system planning process. These would be smaller scale, targeted improvements that can be deployed on a relatively quick timeframe as compared to an annual planning and pre-approval process. This would enable the Common System Modification Fee to provide EDCs with a more flexible revenue stream to cover common upgrades and enable continued deployment of distributed generation co-located with load. This fee would help to alleviate the current condition where front of the meter resources have not been paid for using the hosting capacity associated with behind-the-meter load, and now when behind-the-meter customers seek to install DG, they trigger upgrades. Collecting the fee from Expected and Standard projects as well as Simplified projects ensures that funds will continue to be collected and available to offset such upgrades.

[72] Att. A, p. 5, FN 2 (referencing eligible upgrades, which all seek to open hosting capacity on a relatively broad scale; for example, not open hosting capacity to a particular site).

ii. Is a <u>fixed</u> Common System Modification Fee appropriate? If so,

> **1. Provide a proposed method for establishing such a fee.**
> **2. Explain how the proposed fee levels are appropriate considering the level of investment required to support the types of investments the fee is intended to cover.**
> **3. Explain how proposed fee establishes clear cost signals, provides cost certainty, and limits ratepayer costs.**

iii. Explain how such a fee would interact with the distribution system planning process described in Section II.

A fixed fee is only appropriate if the fee equation reflects a project's interconnection cost according to the relative grid impact of the interconnecting customer. DOER's response to the remainder of this question is encompassed within b.i.4. above.

> **1. As part of your explanation indicate whether a maximum price for Common System Modification Fees is appropriate.**

DOER recommends the cost be set as low as practicable to enable recovery of upgrades while not slowing the development of DG in Massachusetts. As noted above, the DOER Proposal's recommendation for setting fees on a cost-basis can be reduced to reflect the Department's proposed Capital Project Investment Fee. Since Capital Project Investment Fees are anticipated to cover most of the higher-cost system upgrades, the Common System Modification Fee can likely be set at a substantially lower cost than originally considered in the DOER Proposal. Above, DOER recommends maintaining the cost-basis for fee establishment. The intended result is a balanced fee that fully recovers the costs of upgrades, and appropriately allocates those fees.

As proposed by DOER, the Common System Modification Fee would remain static until updated by the Department. Any update would benefit from continued real-world cost data to be provided by the EDCs. As such, the Common System Modification Fee would not require establishing a cap.

Similarly, a Common System Modification Fee structured as proposed by DOER does not require a cost cap specific to projects, as it is designed to scale with project size. Further, DOER's proposed use of the fund to alleviate upgrade costs for BTM projects ensures interconnection fees will remain reasonable for DG projects co-located with load.

2. If a maximum price is appropriate, explain how such a cap would be determined.

iv. Should Common System Modification Fees be based on nameplate capacity and/or export capacity?

Both play a role in the fee structure. The nameplate capacity aspect of the fee ensures a customer pays a share of the interconnection cost even when it is non-exporting, and reflects that real upgrade costs exist, even associated with non-exporting projects. The export capacity aspect of the fee is important to align the interconnection fee cost with the relative impact the proposed facility will have on the distribution system.

1. **If you propose that the fees be based on a combination of the two, please clarify how they should be weighted.**

In the DOER Proposal, DOER provided an illustrative example fee calculation weighting about 20% of the fee on nameplate capacity and 80% on export capacity.[73] DOER explained that the weighting in the calculation could add up to more than 100% of the $/kW fee as identified on a retrospective cost-basis. DOER strongly weighted the proposed fee to export capacity, because facility exports are the largest driver of system impact and upgrade costs.

The fee both attributes a higher cost to projects with a higher impact on the system, and provides a price signal to developers and customers to right-size systems to align onsite generation with onsite load. This price signal becomes increasingly important as we consider coincident

[73] D.P.U. 19-55, DOER Proposal, Section III.A., p.5.

electrification of buildings and transportation as the grid is expected to continue hosting additional renewable DG.

v. Since it is unlikely a Common System Modification Fee would cover all necessary upgrades:

1. Provide a proposed method for how to determine which upgrades would be covered by the funds collected.

DOER recommends the Common System Modification Fee be prioritized to funding upgrades necessary for the interconnection of DG sited at customers with existing load.[74] Common System Modifications that benefit projects associated with Simplified projects should be prioritized over other upgrades.

2. Explain if such upgrades covered by the Common System Modification Fees would be subject to Department approval.

DOER recommends that all capital upgrades be subject to Department review and approval. DOER recommends that the Department pre-approve Common System Modification upgrades enabling Simplified interconnections by type. This will provide the EDCs with the requisite flexibility to pay for individual service transformer replacements as they are identified without waiting for annual planning processes.

I. CONCLUSION

DOER looks forward to participating in this investigation as it proceeds forward, and respectfully requests that the Department consider and adopt the recommendations made within this comment, as it sees appropriate.

[74] Please note, the proposal may benefit from thresholds to prevent potential gaming.

Respectfully submitted by,

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