THE COMMONWEALTH OF MASSACHUSETTS
OFFICE OF THE ATTORNEY GENERAL
ONE ASHBURTON PLACE
BOSTON, MASSACHUSETTS 02108

MAURA HEALEY
ATTORNEY GENERAL

(617) 727-2200
(617) 727-4765 TTY
www.mass.gov/ago

December 23, 2020

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

Re: <u>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.</u>

Dear Secretary Marini:

The Massachusetts Office of the Attorney General ("AGO") submits the following 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

a. Background/Procedural History

On October 22, 2020, the Department of Public Utilities (the "Department") opened an investigation into Electric Distribution Companies' ("EDCs") (1) distributed energy resource planning ("DER") and (2) assignment and recovery of costs for the interconnection of distributed generation ("DG"), docketed as D.P.U. 20-75.[1] The Department previously received proposals that included alternatives to the cost causation principle for interconnection costs. *Distributed Generation Interconnection*, D.P.U. 19-55. Here, the Department seeks comment on its proposal for a new DER planning process and on methods for cost assignment and recovery associated with DER interconnection.[2] *See* Order at Attachment A. D.P.U. 20-75 builds on D.P.U. 19-55, where the Department began investigating cost assignment and recovery associated with DG

[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 (October 22, 2020). While the Massachusetts Standards for Interconnection of Distributed Generation currently focus on "distributed generation," ("DG") includes a broader set of technologies, such as energy storage.

interconnection. As part of its investigation in D.P.U. 19-55, the Department sought and received near-term proposals for alternatives to the Cost Causation Principle[3] for assigning and recovering DER interconnection costs.[4] While D.P.U. 19-55 focused on near-term solutions, the Department's Straw Proposal ("Straw Proposal") in D.P.U. 20-75 prioritizes the development of a longer-term approach for both DER planning and altering cost causation principals.[5] 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.[6]

b. The Straw Proposal

The Department's Straw Proposal contemplates two main components – distribution system planning to accommodate DER and cost allocation proposals to pay for system upgrades triggered by or for DER buildout. Regarding distribution planning, the Straw Proposal requires "a system planning analysis for infrastructure investment in consideration of clean energy and climate policy objectives, incorporation of DG investments, and development of associated planning criteria."[7] The Department proposes that this planning be conducted by the EDCs on an annual basis as an "assessment," utilizing a rolling, 10-year planning horizon.[8] The Department pledges to detail planning criteria in the future, with stakeholder input, for the EDCs to rely on in conducting the assessments.[9]

Regarding cost-allocation, the Straw Proposal includes two new fee structures to supplement the cost causation principle traditionally applied to DER interconnections. First, the Straw Proposal envisions a distribution system planning process that allows the EDCs to identify and undertake distribution system upgrades ("Capital Investment Projects" or "CIPs") that "accommodate forecast load growth and Facility interconnection" or "enable the interconnection of additional capacity beyond currently proposed facilities."[10] EDCs can identify CIPs through an annual distribution system assessment or through DER interconnection studies and potentially receive special ratemaking treatment for these investments through a reconciling charge.[11] Second, the Proposal introduces Common System Modification ("CSM") fees requiring interconnecting facilities to pay CSM fees upfront regardless of whether their interconnection triggered necessary upgrades. The Straw Proposal does not offer a specific CSM; rather, it seeks

---

[3] Under the Cost Causation Principle, "the entity responsible for cost to be incurred is responsible for payment of the costs (cost responsibility follows cost incurrence)". D.P.U. 20-75, at 2.
[4] On February 28, 2020, the AGO submitted a DER Interconnection Cost Allocation Proposal report by Strategen Consulting. *See Hearing Officer Memorandum*, D.P.U. 19-55, at 4 (December 26, 2019).
[5] D.P.U. 20-75, at 4.
[6] *Id*., at 2, 7, Att. A at 16.
[7] *Id*., at 6.
[8] *Id*., at 4.
[9] *Id*., at 5.
[10] *Id*., at 4-5.
[11] *Id*., at 5.

stakeholder feedback on several different types of possible fees. These include, a minimum fee, a fixed $/kW fee, a cost ceiling, and a CSM fee based partially or entirely on export capacity.[12]

c. Summary of AGO Comments

The Department's Straw Proposal is a significant step towards the development of a cost-effective process for upgrading significant portions of the electric distribution system. The AGO agrees that the EDCs should perform regular distribution system planning.[13] To be effective, however, the planning process must recognize the complexity and breadth of the task. Failing to comprehensively plan for a future grid that is resilient enough for the type of DER deployment needed to support the Commonwealth's Net Zero goal is likely to drive a cycle of costly and unnecessary utility investments. Thorough planning is essential to ensure that infrastructure is not repeatedly upgraded before the end of its useful life. Done correctly, such planning will optimize results for all stakeholders -- ratepayers, the EDCs and DER developers. Below, the AGO recommends various near- and long-term additions for an expanded planning process with those goals in mind.

First, the AGO recommends that as the Department carries out its Straw Proposal, it include a broad range of stakeholders, including subject matter experts ("SMEs"), the EDCs, and other stakeholders, in the distribution planning process and require that DERs meet national certification standards for inverter-based DERs. Second, the AGO recommends that the Department convene a working group to conduct a collaborative pre-implementation process and develop a DER Integration Roadmap (See Section 3 below). Both the pre-implementation process and the DER Integration Roadmap will help inform the EDCs' 10-year plans by ensuring that advanced DER integration approaches are standardized and then incorporated into the EDCs' planning processes and assumptions in order to optimize DER benefits and drive the most effective distribution system investment. Third, regarding cost allocation, the AGO recommends that the Department and stakeholders further explore the concept of exports and an export tariff in the planning process and do so before implementing the CSM.

2. General Enhancements to DER Planning Proposal

DER planning for the distribution system, including the regular EDC assessments contemplated by the Straw Proposal, can optimize DER benefits and provide a more efficient, modern, and nimble distribution system. Achieving such a successful, sustained DER planning process requires a broad range of perspectives and technological knowledge to set the standard of what is expected in the annual assessments. Therefore, to allow for a complete and more useful ten-year rolling assessment of the distribution system as contemplated by the Straw Proposal, the AGO recommends the involvement of a broad stakeholder group including the Department, the AGO, the Department of Energy Resources, the EDC planning group, the EDC operations group, the EDC interconnection group, DER owners, site developers, and operators of DER ("DER

[12] *Id.*, at 11-12.

[13] While the Department proposes annual plans, distribution companies and states around the country are moving to bi-annual distribution system planning in order to allow for fuller discussions of proposed recommendations and additional time for utility commission oversight.

Stakeholder Working Group") in the pre-implementation process and the DER Integration Roadmap process discussed below. Collective stakeholder involvement will help ensure that the value of distribution system planning is maximized for all stakeholders.

DER planning also would benefit from the use of standardized technological protocols that enable the optimization of DER benefits. Thus, the AGO recommends that the Department require that DERs that are connected to the Commonwealth's distribution grid meet national standards for the certification of inverter-based DERs (normally solar and energy storage). Such standards guarantee that compliant DERs meet certain requirements associated with their operational performance, resulting in known operational characteristics that can be used by all stakeholders and be incorporated into the planning process.[14] For the DER owner/operator or site developer, the ability to use standard functions of "smart" inverters as a service offering to the EDC or others may provide additional revenue streams or avoided expenditure that, when combined with expert EDC operational knowledge, could result in deferral or elimination of unnecessary upgrades to the system.

3. **Recommended Stakeholder Processes**

The intent of the Straw Proposal's annual, rolling ten-year plans cannot be achieved without an extensive framework of expectations, data requirements, and technological understanding by the EDCs, informed by a broad group of experts and stakeholders. Thus, the AGO recommends two sequential planning processes similar to the processes used in California, Hawaii, and New York. First, the Pre-Implementation process will determine the current functional capabilities of the EDCs to incorporate additional DER on a company-by-company basis. Second, the DER Integration Roadmap process will standardize DER treatment in the Commonwealth. Ultimately, each EDC's 10-year assessment will apply the uniform DER Integration Roadmap in their respective territories. Finally, the AGO recommends that the Department assign the DER Stakeholder Working Group to carry out both planning processes described below.

a. Pre-Implementation Process

The AGO recommends that the DER Stakeholder Working Group undertake a **Pre-Implementation process** to establish the current functional capabilities of each EDC to incorporate additional DER. First, the DER Stakeholder Working Group will draft a public document detailing a state-wide vision for the Commonwealth with respect to distribution system planning and cost allocation. The document will set forth what the Department and the stakeholders expect in terms of standardized future DER deployment and technological capabilities and what the EDCs' ten-year assessments should include to meet that future. Separately, each EDC will develop a baseline of knowledge of its individual distribution system

[14] For example, standardized monitoring of DERs can benefit the EDC planning process by ensuring that data collection is uniform across all DERs, which removes the need for multiple monitoring systems. For the EDC operations team, standardized monitoring and control enables the ability to repeatedly and consistently apply best practices in management of utility systems, resulting in maintaining and possibly improving safety and reliability of delivery. The cost-effectiveness of controlling DERs will vary based on size, use cases, and technological advances.

and existing DER technology capabilities. Finally, each EDC will conduct a gap analysis/closure action plan which will identify the gaps between the DER Stakeholder Working Group vision and the EDC's baseline capabilities. Each EDC's gap analysis/closure action plan will be subject to SME review and suggested improvements to ensure cohesion with the vision. (see Appendix A for details on each of these steps). Thus, the Pre-Implementation process will produce a public, Commonwealth-wide vision statement for DER planning as well as EDC-specific readiness gap analysis/closure action plans to inform the DER Integration Roadmap process. As detailed further in Appendix A and Table 1 below, the Pre-Implementation process tasks can progress concurrently.

b. DER Integration Roadmap

Next, the AGO recommends that the Stakeholder Working Group expand upon the vision statement and gap analysis/closure action plans by developing a **DER Integration Roadmap.** The Roadmap will establish a framework of technological, process, and regulatory considerations for the EDCs to use to inform their individual ten-year assessments. The DER Integration Roadmap will seek to standardize DER technology integration and leverage DER penetration in a way that reduces or eliminates specific needs for system upgrades.[15]

To develop the DER Integration Roadmap, the Stakeholder Working Group[16] will undertake five tasks:

- Establishing a common baseline for DER standardization;
- Developing recommendations for default and/or unattended functions that leverage advanced DER;
- Developing recommendations for monitoring and control communications requirements to interact with advanced DER;
- Developing recommendations for advanced bulk electric system reliability settings within advanced DER; and
- Developing recommendations for advanced, interactive settings within advanced DER.

As detailed further in Appendix B, these tasks need not be done sequentially as several of the tasks can progress concurrently. Table 1 provides details on the proposed timeline for the Pre-Implementation and the DER Integration Roadmap processes.

[15] The DER Integration Roadmap is based loosely on the New York smart inverter working group, with improvements to reflect lessons learned.

[16] The AGO notes that it is likely that the Stakeholder Working Group will be divided into multiple sub-groups to efficiently address the five tasks.

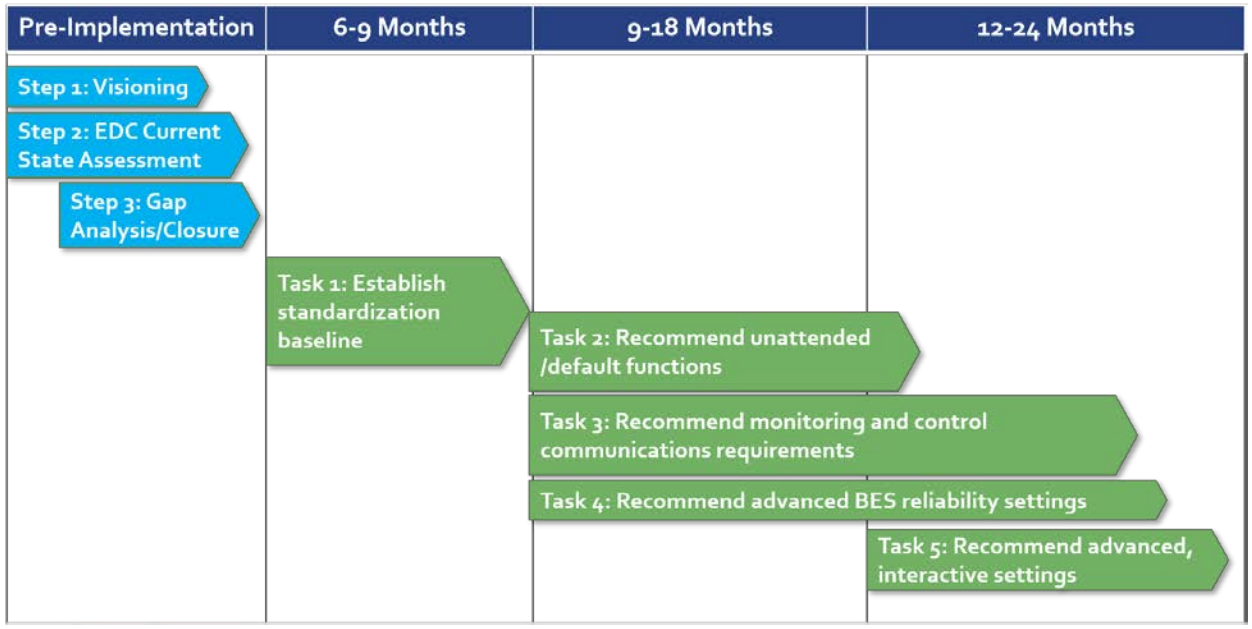

Table 1. DER Planning Timeline

c. DER Stakeholder Working Group Make-Up

The AGO recommends the Department establish a DER Stakeholder Working Group consisting of the broad group identified *supra* to work as collaboratively as possible, with certain sub-groups identified to break out for limited tasks.[17] Learning from other states' experiences, the AGO recommends that the Pre-Implementation and DER Integration Roadmap processes be led by a non-EDC Subject Matter Experts ("SME") facilitator, at the direction of the Department. This would operate similarly to the Distributed Generation Working Group established in D.P.U. 11-75, with the SME guiding the DER Stakeholder Working Group in a collaborative process, embracing a big tent philosophy to a maximize information sharing and planning expectations.[18] As noted in Appendix B, certain tasks may require the lead SME to delegate sub-groups with specific SMEs directing those activities. Regular reporting to the Department on progress by the DER Stakeholder Working Group will increase transparency and accountability.

4. Assignment and Recovery of Costs

The Department's Straw Proposal introduces two types of fees for collecting DER interconnection-related system upgrade costs: CIP fees and CSM fees. The CIP and CSM fees

[17] Critics of a similar proceeding underway in New York argue that the sub-groups evolved into such distinct and separate groups that progress was compromised. Common issues and challenges permeate each stage of planning, and thus, stakeholders should work as one team as much as possible.
[18] *Order Establishing Distributed Generation Working Group*, D.P.U. 11-75, at 4 (January 23, 2012).

would significantly alter the way that DER-related upgrade costs are collected from interconnecting facilities. In this section, the AGO recommends that the Straw Proposal incorporate several processes to ensure efficient management and pricing of export capacity and to protect ratepayers from unreasonable upgrade-related costs. The section is partially responsive to Department's questions 1.c, 2.a and 2.b.[19]

a. The Department's Proposals

Currently, distribution system upgrade costs are assigned based on the Cost Causation Principle, which dictates that the facility triggering the upgrade must pay the entire upgrade cost.[20] The Department's CIP fee proposal introduces a new approach to cost assignment and recovery. Under the Straw Proposal, EDCs would fund a CIP upfront and have the opportunity to recover that cost from ratepayers through a reconciling charge. When subsequent interconnecting DERs utilize the capacity enabled by that CIP, they would pay the EDCs a CIP fee representing the dollar-per-kilowatt ("$/kW") cost of the investment, scaled to the capacity of the interconnecting DER.[21] The Straw Proposal posits that if DERs utilize the full amount of capacity enabled by the CIP, ratepayers would incur a net zero cost over the ten-year period.

In addition, the Department requested comments regarding whether there are CSM fees that may better facilitate system upgrades that benefit more than the interconnecting facility.[22] In recognition of the aggregate operational and infrastructure impacts that DERs impose on the electric power system, interconnecting facilities would pay CSM fees upfront regardless of whether their interconnection triggered necessary upgrades. The Straw Proposal seeks comment on different fee mechanism such as a minimum fee, a fixed interconnection fee, a cost ceiling, and weighing fees based on export.[23]

b. The Distribution Regulatory Paradigm Changes Reflected in the Straw Proposal

While the CIP and CSM fees represent a step towards more equitable DER upgrade cost allocation, they also represent a significant change to the distribution regulatory paradigm: EDCs must now plan for export capacity and fairly allocate that export capacity cost.[24] This change is a necessary response to the reality that DERs challenge traditional distribution planning—where the EDCs used to worry about power flow only to the customer, advances in technology now require attention to the bi-directional flow of electricity to and from the customer

[19] D.P.U. 20-75, Att. A. at 13-15.

[20] D.P.U. 20-75, at 3.

[21] The Department proposes that CIP fees apply for 10 years after the project's pre-approval. DERs interconnecting under the Simplified Process are exempt from CIP fees. *Id.*, at 6.

[22] *Id*., at 9.

[23] *Id*. at 11-12

[24] In the case of energy storage, there will be both DER-related export and import costs. It is not clear the extent to which energy storage is currently connected to the EDCs' distribution grids, but based on experience in other jurisdictions, there could be significant grid-connected storage capacity in the near-future.

(import/export). The Department's proposals represent near-term steps in adjusting the current regulatory paradigm to account for export capacity, *i.e.*, the flow of electricity from the customer to the grid. Indeed, the Department acknowledges the changing regulatory paradigm by internalizing export capacity into distribution system planning: CIPs allocate pre-emptive DER-related costs through a locationally specific $/kW fee while CSMs would allocate some estimate of shared DER-related costs through a common $/kW fee. These fees anticipate and assume the need for additional capacity to accommodate maximum DER export at any time.

Pre-building or pre-charging in anticipation of excess export capacity in turn creates a new distribution resource that EDCs must efficiently manage and price. Efficient management and pricing of export capacity is likely to evolve over time as technologies mature. For this reason, efficient management and pricing of export capacity is a long-term goal that warrants additional process, time, and resources. In the near term, however, improving cost allocation using price signals that do not impede future efficient pricing structures is important. In order to contextualize the AGO's recommendations on cost allocation, it is crucial to recognize two important components of the changing regulatory framework that are not reflected in the Department's proposals: export service options and export pricing structures.

1. Define and Broaden Interconnection Service Options

Clearly defining the service that DERs pay for with a CIP or CSM fee is an important step in efficiently using distribution resources. Other interconnection cost allocation arrangements define the service being paid for (*e.g.*, firm interconnection rights), but the DER interconnection process in the Commonwealth has not been so explicit. Defining DER service options is important because there are numerous ways that DERs could interact with available distribution export capacity. For example, dynamic curtailment could be thought of as a non-firm export capacity service, similar to how large customers often have interruptible import tariffs for retail service.[25] However, Massachusetts regulations and the Department's proposals seem to suggest that DERs only interconnect under firm service because there is no apparent language that suggests otherwise.[26] This implies that DERs will export unconditionally no matter the time of year, hour of the day, location of the DER, or other grid conditions.[27] Implicitly assuming that all DERs need firm service and, therefore, that all DERs will export at maximum capacity during a worst-case scenario on the distribution grid leads to unnecessarily overbuilding the system to accommodate this potential despite the availability of mitigation alternatives.

In fact, there may be several options for import and export service, including firm, as-available, and dual interconnection services.

---

[25] E.g., Eversource's Load Management Program. Available here: [Microsoft Word - MDPU 58_EVERSOURCE_LRP_clean.docx]()

[26] A cursory review of the DG interconnection tariff and line extension policies does not reveal explicitly defined export rights associated with distribution system upgrades. *National Grid Standards for Interconnection of Distributed Generation*, M.D.P.U. No. 1320. (Effective October 1, 2016), *National Grid Terms and Conditions for Distribution Service*. M.D.P.U. No. 1412 (Effective October 25, 2019), and D.P.U. 20-75, Att. A.

[27] 220 C.M.R. 8.00; 220 C.M.R. 18.00.

- **Firm service** provides a facility with reliable import and/or export capacity. Firm service has traditionally been a 24/7/365 product but could evolve towards more temporal capacity availability. For example, in the future, customers could elect to have firm capacity time blocks or be exposed to time-varying kWh or kW charges.

- **As-available service** provides a facility with capacity on an as-available basis. This may entail curtailing export in real-time remotely or in a discrete period of time through a utility signal.

- **Dual service** provides a facility with partial firm and partial as-available service. For example, a customer would be allowed to select firm service for a portion of export capacity and as-available service for the remaining portion, allowing for dynamic power curtailment of the as-available portion of the DER's capacity, but not for the firm portion.

Many utilities offer dual service for imports through interruptible tariffs. California is piloting a retail interconnection process with similar options and has had ongoing discussions about wholesale tariff structures as well.[28] Defining a broader suite of service options for DERs will drive fee development and more efficient and effective system planning. Interconnection fees should be based on cost causation, so fee structures should be directly linked to the type of service a facility selects during the interconnection process. Without service and fee differentiation, DER developers will have little to no incentive to modify export and the associated costs caused. For example, if a facility is charged an interconnection fee based on estimated firm export requirements with no other options, the facility will have little reason to participate in a dynamic curtailment program or limit its export capacity in other ways. With differentiated services and fees, developers can weigh business decisions against the costs caused to the grid. For these reasons, the AGO recommends the Department and stakeholders further define service options as they relate to DERs.

2. Explore Efficient Interconnection Pricing Structures

Just as the assumption of firm DER service could contribute to overbuilding the distribution system, so could using a fixed $/kW charge to collect distribution system costs. The Department's $/kW fees for CIPs or CSMs can be interpreted as export fees, based on the potential costs caused by the maximum output of a DER during a worst-case scenario. The implication is that a $/kW disincentivizes all export onto the distribution system. Optimally, however, export should be incentivized when it can benefit the grid and discouraged when it will cause costs, such as at times with low net load. Thus, the AGO recommends consideration of DER interconnection price mechanisms that optimize export behavior to create a more effective pricing structure.

The main way to incent efficient export behavior is to base the price on cost causation, with a modernized view of what drives the causation component. This would mean charging facilities

[28] GuidetoEnergyStorageChargingIssues.pdf (pge.com)

based on export capacity rather than installed capacity. DER facility size does not necessarily cause costs; export does. Indeed, not all export causes capacity-related costs; export during constrained times does. One way to incorporate this temporal cost causation concept into pricing structures is to charge exporting facilities system usage charges throughout the life of system through an export tariff as opposed to a lump sum fee when interconnecting.[29] Because the EDCs manage excess export capacity, an export tariff may be a reasonable long-term solution because it can incorporate evolving system costs, incent behavior through time, and more equitably recover export capacity from those that utilize that function of the system.[30] However, planning and pricing for export capacity likely exceeds the EDCs' current capabilities and an export tariff requires careful design. Thus, for the time being, a $/kW export fee may be the best available mechanism, even if it disincentivizes beneficial as well as harmful export. In the long run, the AGO recommends that fees move to more granular, temporal cost-based pricing.

c. Short-term Interconnection Service and Pricing Recommendations

The AGO recognizes that while establishing efficient pricing tariffs for DER export and import may require long-term technology implementation and ratemaking, other DER interconnection issues require more immediate resolution. The Department's $/kW pricing proposals can address the immediate interconnection queue while a more flexible and dynamic long-term distribution planning process and corresponding cost allocation approach is designed.

As with so many of the processes under consideration here, the ability of stakeholders to make reasonable and effective recommendations depends on the availability of record information and data from the EDCs. For example, identifying implementable modifications to the Department's proposed $/kW fees requires more detail about the EDCs' current technology, by size of facility, including whether the EDCs can currently offer dual service for import and/or export and have the technical ability to dynamically curtail.[31] Indeed, like some of their counterparts in other regions, the EDCs may use alternatives for curtailing imports on the distribution system. Understanding such baseline information is necessary before discussing whether similar functionality could be developed for export. The AGO recommends that the Department, through stakeholder discussions and further development of necessary record evidence, identify the various interconnection services that EDCs can implement in the short run to supplement, and improve the CIP and CSM proposals.

d. Ratepayer Protections Against Unnecessary Overbuilding

---

[29] *See* Consultation Paper: Distributed Energy Resources Integration - Updating Regulatory Arrangements. Australian Energy Market Commission. July 30, 2020. Available here: https://www.aer.gov.au/publications/submissions/aemc-rule-change-consultation-paper-distributed-energy-resources-integration-updating-regulatory-arrangements *See also* Distributed Energy Resources Integration Program – Access and pricing (arena.gov.au)
[30] *Id.*
[31] The AGO recognizes that some of this detail is pending response to Department inquiry in this comment proceeding.

The Department's CIP fee proposal is likely to be an effective tool for addressing the immediate need for more distribution capacity to accommodate DER growth. However, crucial ratepayer considerations must accompany the CIP proposal. CIPs create a large revenue opportunity for EDC shareholders because EDCs are permitted to identify a variety of distribution system upgrades and immediately charge those upgrades to ratepayers.

First, the EDCs will have a significant incentive to overestimate the export capacity required and little incentive to ensure installed export capacity is efficiently utilized. A lack of criteria for sizing CIPs in a reasonable way lends itself to overbuilding based on EDC economic incentives. Additionally, because EDCs earn a return on their investment regardless of whether DERs interconnect to CIP sites, they have little incentive to ensure that the excess capacity enabled by the CIP is utilized efficiently. If DERs do not utilize that excess capacity, ratepayers will have unnecessarily paid to upgrade the distribution system. To address this significant ratepayer risk, the AGO recommends the Department require performance metrics around CIP utilization. Developing such metrics will require data collection to track utilization and performance measures.

Second, under the Straw Proposal, ratepayers are now responsible for financing export capacity. Distribution system upgrades were previously paid for by third parties, without a return from ratepayers. Under the Department's proposed CIP structure, EDCs will finance the CIPs and charge ratepayers a return. Given that DER developers will likely pay off such financing before the depreciation timeline of the asset expires (particularly if sized correctly), the EDCs will receive a windfall from ratepayers due to the complex cost recovery and associated accounting rules that remain unclear under the Straw Proposal. Additionally, the EDCs will earn revenue through different structures depending on whether an investment is export or import related. For example, export-related investments will be paid for through lump sum fees at the time of interconnection, while import-related fees are collected through retail tariff structures. Retail tariffs for import are structured to allow the utility a reasonable opportunity to recover the cost of its investment with a return over the life of the investment. Lump sum payments accelerate cost recovery and reduce risk for EDCs compared to retail import tariffs. Therefore, the AGO recommends that the Department reduce or eliminate ROE for investments that receive these special ratemaking treatments because risk is substantially lowered.

Finally, because the CSM fees will apply across the entire distribution system, the AGO recommends that prior to adopting a CSM, the Department develop a more wholistic vision of how cost allocation and fee collection could evolve in the future. A CSM will likely make sense within a larger framework. However, without understanding the interconnection service that DERs currently pay for, the set of possible future services that will be available for purchase, and how to optimally price these services, the Straw Proposal may create barriers to future efficient pricing.[32] Choices made today could limit future options. For that reason, before the

[32] For example, grid connected energy storage systems have connected under as-available service in other states, such as California, then utilities have offered firm service at a later date. The interaction between these services has the potential to create inequities and additional costs for ratepayers.

Department adopts system-wide CSM fees the Department and stakeholders should further explore export related cost recovery and the feasibility and efficiency of export tariffs.

e. Long-term Interconnection Cost Assignment and Recovery

The AGO recommends additional process to determine the most efficient long-term interconnection cost recovery approach. The most effective approach will require implementation over time, evolving alongside the EDCs' distribution planning and technology capabilities, as projected within the DER Integration Roadmap described in Section 2(b). As EDCs are able to offer the variety of services described above, they will also be able to price those services more efficiently. To do so, it may be more efficient to recover costs through export fees via the ongoing use of distribution system tariffs, rather than through an upfront fee. For example, a monthly service usage charge based on a system's measured monthly or temporal exports would give DERs an incentive to shift export into times that benefits the system. Such a structure would reflect the costs and value of DER to the grid, and therefore encourage export during times that reduce the need for system upgrades (*e.g.*, during local/system peak load) and discourage export at times that would trigger system upgrades (*e.g.*, low net load).

Dynamic pricing structures are critical to cost assignment and recovery, especially when excess export will be managed by EDCs over time, because export behavior can change over time. Such changes are not reflected in an upfront $/kW fee.[33] The dynamic nature of export requirements may result, from an efficiency standpoint, in the need to price export (*i.e.*, collect the costs) more dynamically and over the life of the investment.

In addition to export-related cost causation issues, the Department should consider imports related to grid-tied energy storage facilities. The extent to which energy storage systems charge from the grid in Massachusetts is unclear. However, grid-tied energy storage facilities are on the rise in many states, including New York. Thus, the AGO recommends that the Department consider energy storage import tariffs to avoid unnecessary delays to storage deployment.

While the Straw Proposal does not address export capacity, for the reasons described herein, the AGO recommends that the Department investigate the efficient pricing of export capacity to complement the pending CIP and CSM proposals. This could be accomplished through

[33] For example, if a box store interconnects a large PV system, it should be very clear what service they are paying for. Under current regulations and proposals, it seems that they would be buying firm service. The box store might initially utilize 0.5 MW of excess export capacity when initially interconnecting and pay a $/kW CIP fee. However, if the box store alters its load profile significantly, say through electrification of heating or electric vehicle charging in its parking lot, it could feasibly reduce or eliminate its export. It is unclear what would happen to the 0.5 MW of export capacity at this point. Is it baked into distribution system planning, or does the box store have some financial right to this capacity? Then assume another significant alteration to the store's load profile occurs through the installation of an energy storage system, which results in the store's restored desire to export 0.5 MW. Does the store have to pay the CIP fee again or do they have 0.5 MW of firm capacity?

Department conducted technical sessions or a designated Export Working Group. The exploration of export capacity would be distinct from the DER Stakeholder Working Group recommended in Section 3. If the Department establishes an Export Working Group, the AGO recommends four to six stakeholder working group sessions, with a summary report due to the Department before the end of 2021. The Export Working Group would determine what export capacity is, what it could mean for the Commonwealth, and if export capacity tariffs could work at our EDCs. The objectives for the group would be to define the export services in the near and long-term and investigate the most efficient way to price such services.

5. Conclusion.

The AGO appreciates the Department's Straw Proposal and the opportunity to offer comments on such and the posed questions. The AGO respectfully requests the Department consider the comments offered herein, including the suggested process additions to the Straw Proposal regarding (1) DER Pre-Implementation process; (2) DER Integration Roadmap tasks; and (3) expansion of cost allocation considerations to include exports. The AGO looks forward to participating further in this investigation.

Sincerely,

s/ Elizabeth Mahony
Elizabeth Mahony
Shannon Beale
Ashley Gagnon
Assistant Attorneys General
Energy and Telecommunications Division

cc: Kate Zilgme, Hearing Officer

Appendix A
Pre-Integration Planning Steps

The AGO recommends the following Pre-Implementation process:

- **Step 1: Visioning**. The visioning component of the Pre-Implementation process establishes the desired outcomes of DER planning, including the incorporation of interactive DER (*e.g.* "smart inverters" or "SI") into the distribution system in an effort to lower costs of interconnection, the streamlining of EDC planning and operations with interconnected DER, and the deferral or elimination of potential upgrades. All members of the DER Stakeholder Working Group should participate in this visioning activity, as each has a vested interest in a positive outcome that supports their business goals. Visioning should produce a comprehensive set of business and technical use cases, based on inputs from stakeholders, that guide all remaining activities (in both this Pre-Implementation planning and the DER Integration Roadmap recommended below). The vision step will produce a concise public document that establishes the vision, business objectives, use cases, and high-level requirements that enable a successful framework for DER planning and investment. The AGO recommends the DER Stakeholder Working Group file the vision for Department approval as a means to improve EDC confidence in the DER investments made to meet the vision and the associated cost recovery of those investments.

- **Step 2: EDC Current State Assessment**. Next, the readiness of each EDC to achieve the agreed-upon vision should be assessed. To accomplish this, each EDC should create high-level solution(s) of how to accomplish the vision, in accordance with existing capabilities as well as approved, planned improvements. Each EDC, with the direct involvement of SMEs, should report on which of the necessary technologies, processes, or personnel it possesses. Such self-assessment should be guided by a transparent and collaborative stakeholder process using the lessons and predictive intelligence of the industries' experience. The outcome of the current state assessment component will be EDC-specific confidential documents for the Department (and appropriate stakeholders) and a complementary public presentation detailing the ability or inability of each EDC to achieve the agreed-upon vision.

- **Step 3: Gap Analysis/Closure**. Finally, each EDC will conduct a gap analysis/closure to clearly describe technology/process gaps, regulatory hurdles, and other influencing factors identified by comparing the Step 1 Vision against the Step 2 EDC Current State Assessment. Step 3 will include both a gap analysis assessment stage and a gap fill/closure stage. Each EDC will conduct a gap analysis assessment to identify what needs to change in order to achieve implementation of the collective stakeholder vision. Gap analysis assessment includes both items within the EDC's capabilities to resolve, given the proper resources, and mitigating factors outside of the EDC's control (e.g. regulatory or other factors). Gap closure should produce a high-level plan that shows how to address and mitigate factors established during the gap analysis assessment. Gap closure can harmonize existing capabilities as well as approved, planned improvements to leverage prior work and investments. The DER Stakeholder Working Group will review the gap analysis and provide feedback in order to affirm the vision is achieved in a cost-effective way. Each EDC will produce its own gap analysis action plan detailing its capabilities and divergence from the vision. Collectively, the gap analysis/closure action plans will inform the phased, multi-year DER Integration Roadmap that achieves the desired visioning outcomes, as well as a confidential series of detailed documents that address the specifics of implementation.

Appendix B
DER Integration Roadmap

The AGO's recommended DER Integration Roadmap is designed with the following five tasks, as led by the Department-selected SME facilitator and the DER Stakeholder Working Group. Each task should be facilitated by specific (non-EDC) SMEs who can advise on industry best practices, coordinate meetings between the different sub-tasks/groups and ISO NE and prepare reports/presentations as necessary. For some tasks, sub-groups may be appropriate but will operate under and report to the facilitator (see below).

DER Integration Roadmap Tasks

- **Task 1: Establishing a common baseline with respect to DER standardization.** In the past few years, the DER industry, specifically DERs that are inverter-based, underwent a transformational change. The industry has embraced two governing standards, UL 1741 Supplement B and IEEE 1547-2018.[34] Suppliers are moving rapidly to certify their products under these two standards. In contrast, state policies and EDCs are lagging in adoption of these standards with respect to interconnection requirements. Further, many EDCs lack specific resources to leverage and use the capabilities certified by these standards and national bodies, resulting in limited performance and outcomes.

  Task 1 focuses on a careful review of currently available and pending standards, mapping various functions and capabilities that are necessary to complete gaps as identified in the gap analysis/closure action plans (established in Pre-Implementation Step 3 in Appendix A), and setting a foundation of intended outcomes that best represent the business needs of all stakeholders. Task 1 should be facilitated on a periodic and repeating basis to guide the EDCs to understand existing and pending standards as well as the applicability of those standards to meet identified gaps. While the current iteration of the Technical Standards Review Group may address certain of these standards, conducting this task within this process connects the standards to the planning process, ensures public involvement and transparency, and provides for Department oversight.[35] Task 1 should result in a public document/presentation that details the changes to the existing state

[34] *See also,* National Association of Regulatory Utility Commissioners ("MARUC") Resolution Recommending State Commissions Act to Adopt and Implement Distributed Energy Resource Standard IEEE 1547-2018, at 1-2 (February 12, 2020) ("Resolution"). The NARUC Resolution recommends state commissions to convene proceedings with stakeholders to "align implementation of the standard with the availability of certified equipment." Id. at 2.
[35] *See* New York's Interconnection Technical Working Group where the New York Department of Public Service receives presentations and comments from both EDC representatives and the public. Meetings occur regularly to provide staff updates and allow for a fuller exchange of information.
https://www3.dps.ny.gov/W/PSCWeb.nsf/All/DEF2BF0A236B946F85257F71006AC98E?OpenDocument.

policies regarding DER standards that are necessary to close any identified gaps. Task 1 may take 6-9 months to complete.

- **Task 2: Developing recommendations for default and/or unattended functions that leverage advanced DER.** Leveraging the full capabilities of advanced DER requires a robust, secure, and flexible communications network that extends from the EDC back office to the edge of the energy delivery network. This network likely does not currently exist for any of the EDCs in Massachusetts to the extent necessary to achieve the type of DER integration contemplated here. Thus, this task focuses on the development of DER capabilities that do not require communications in order to derive benefit. Known as unattended functions, these non-communicative advanced DER capabilities offer intrinsic safety benefits while providing the ability to reduce or eliminate adverse impacts of connecting DER to distribution circuits. Additionally, actions at the bulk electric system ("BES") level, specifically those associated with ISO-NE, will likely have an influence on the development of settings for the unattended functions. Information from other states (*i.e.*, California, Hawaii, Minnesota and New York) regarding DER unattended functions could be helpful here.

  The intention is for Task 2 to produce a definitive set of recommendations for implementing default and/or unattended functions within advanced DER. The Task 2 SME facilitator should be able to conduct external industry surveys with other utilities. EDCs should then update interconnection requirements to include the recommended unattended functions and default settings as well as establish a timeline for review or subsequent recommendations (recognizing ongoing technological advancements). Task 2 may take 9-18 months to complete.

- **Task 3: Developing recommendations for monitoring and control communications requirements to interact with advanced DER.** Numerous influence factors shape and inform the communications network necessary to leverage advanced DER, including IEEE 1547-2018 harmonization, the use of public/private communication networks, cybersecurity, the impact of DER nameplate sizing on communication requirements, and DER connection considerations (specifically those associated with direct connect to the DER or gateway interface or through third-party aggregators and control authorities).

  In Task 3, the DER Stakeholder Working Group will produce a set of recommendations for the EDCs related to communication requirements associated with interacting with advanced DER. This task can start concurrently with Task 2, but due to its complexity and limited SME resources, likely will extend beyond the conclusion of Task 2. In order to maximize efficiency, this task may be split into smaller working groups focused on specific areas of expertise, including planning, interconnection, operations, cybersecurity, impact of DER nameplate sizing, public/private communications, and endpoint security.[36] Task 3 should result in recommended best practices for different

[36] For example, cybersecurity and DER nameplate sizing SMEs areas. DER nameplate sizing is a typical threshold level triggering different state interconnection rules; a state may have different interconnection rules for nameplates above 1 MW versus those below 1 MW. FERC

communication requirements and corresponding timetable for implementation by the EDC(s). Recommended changes to regulatory rules regarding interconnection requirements should also be produced by the DER Stakeholder Working Group. Task 3 is a complex undertaking and may take 1-3 years to complete.

- **Task 4: Developing recommendations for advanced BES reliability settings within advanced DER.** Deployment of advanced DER on the distribution grid must be in alignment with transmission-based devices that are located in the BES. Correspondingly, unattended settings, as discussed in Task 2, are important because when they are aggregated, they can influence the BES. Hence, it is important to align ISO-NE, DER, and BES settings as well as distribution-connected settings.

  The Task 4 effort will focus on collaboration and coordination between ISO-NE, NERC, NPCC, other stakeholders, and the EDCs to ensure that unattended functions, especially those associated with DER ride-through, DER trip, and other safety and system reliability functions are addressed early in the process and tie directly with Task 2 activities. Task 4 should start in parallel with Task 2 activities, pending availability of resources at the EDC level. Task 4 should be facilitated by a SMEs with knowledge of relevant standards associated with both transmission and distribution connected safety and reliability functions. This task should produce results in two tranches: 1) necessary input to Task 2 activities, ensuring the unattended functions of newly-installed DER maintain safety and reliability as currently maintained; and 2) as DER penetration grows, and as knowledge of advanced DER improves, best practices recommendations for advanced DER interconnection which align with ISO-NE, NERC, and other stakeholders to ensure harmonization across all installed DER systems. Although Task 4 spans a significant calendar window, most of the activities will coincide with Task 2 performance (alignment with ISO NE), with periodic involvement into Task 3 activities (the role of using communications to monitor advanced DER performance in the BES), and a small, concentrated set of activities occurring after the conclusion of Task 3 (how to interact with advanced DER, using communications established in Task 2, to make improvements to the configuration of advanced DER that could influence the BES). Task 4 will take 1-3 years to complete, with most of the work performed early in the timeline.

- **Task 5: Developing recommendations for advanced, interactive settings within advanced DER.** This work effort is focused on tying together the work of the prior tasks. By proactively planning for DERs, enabling smart inverter functions, and providing DER developers with transparent information related to cost causation, Task 5's objective is to ensure all these standards and processes come together to create

---

841 and 2222 thresholds are 100 kW. Cybersecurity issues are not highly dependent on DER nameplate sizing determinations. For this reason, cybersecurity and DER nameplate sizing topics are generally not competing for SME resources and can advance at a normal pace. Similarly, planning and analysis of DER interconnection and public/private communications are generally not competing for SME resources. Conversely, cybersecurity, public/private communications, and endpoint security are generally using the same SME resources and as such may extend the performance timeline of this task.

tangible benefits for ratepayers by integrating DER use cases into the planning and interconnection processes. For example, evaluating dynamic curtailment to defer a system upgrade could be analyzed holistically within an EDC distribution system plan ("DSP").[37] Task 5 builds on a solid foundation that guides much of this final effort: the prior work of Task 3 monitoring, control, and communications; combined with the unattended operational behavior from Task 2 implementation; and, including the Task 4 harmonization of DER safety and reliability settings with the BES as recommended by ISO NE.

Task 5 will establish a comprehensive set of recommendations for the enablement of advanced, interactive capabilities with DER. For example, interactive settings including dynamic curtailment, adjustable power control limiting, and other advanced functions that could potentially benefit safety and reliability of delivery while providing capabilities to increase hosting capacity of a circuit. Although Task 5 activities can start during development of Task 3 monitoring, control, and communications recommendations, most of that work must be completed due to the dependency of Task 5 recommendations on the earlier results. The Task 5 SME facilitator should have a knowledge of the work and considerations that occurred in Task 3 so that these can be brought forward to this task. Future interconnection requirements should incorporate the Task 5 recommendations on interactive functions and default settings. Task 5 may take 1-2 years to complete.

DER Stakeholder Working Group membership

As detailed, the DER Integration Roadmap requires a significant amount of involvement from SMEs, the EDCs, and stakeholders. While led primary by the facilitator to keep all Tasks connected, the DER Stakeholder Working Group will benefit from utilizing members with technical and/or policy discussions as areas of responsibility, establishing sub-groups, and delegating SME leads for Tasks. The Department and/or the Facilitator may find useful the formation of two overarching technical and policy working groups to split areas of responsibilities, *e.g*. a Technical Working Group and a Policy Working Group. Moreover, establishing strategic subgroups, including those listed here, will benefit the overall Task structure. Recognizing the complexity of the DER Integration Roadmap Tasks, subgroups allow for flexibility while maintaining a level of collaboration necessary for a cohesive stakeholder process.

- **Planning and Analysis**: focused on the processes involved in planning associated with DER integration and operation, to include pre/post interconnection analysis, load and generation growth analysis, impact analysis of DER interconnection, hosting capacity analysis, and alternatives analysis. In addition to identification and enumeration of these processes, this subgroup would provide clarity into the planning process and requirements and ensure that advanced DER capabilities are considered and leveraged

[37] To be clear, evaluating dynamic curtailment within a DSP process is distinct from piloting the concept. The AGO maintains its support for moving forward in the near-term with a dynamic curtailment pilot, as proposed in D.P.U. 19-55.

where applicable. For Tasks 2, 3, and 5.

- **Operations**: focused on the processes involved in operationalizing advanced DER, this group's primary responsibility is to establish how advanced DER can be used to maintain and/or improve the safety and reliability of energy delivery. This subgroup would examine operational systems and determine DER requirements to integrate advanced systems into utility operations. For Tasks 2, 3, 4, and 5.
- **Information Technologies**: focused on data specification, security, capture, backhaul, storage, and retrieval, this group's primary responsibility is to ensure that data is properly acquired/transmitted, and made accessible to all users within the utility environment. This subgroup would cover Advanced DER monitoring & control, in conjunction with existing and future capabilities of the field area communication network as well as advanced back office systems. For Tasks 3 and 5.
- **Interconnection**: focused on establishing and maintaining interconnection requirements of advanced DER. This subgroup will necessarily involve coordination with the Planning and Analysis (DER integration and operation), Operations (establish operational requirements for advanced DER performance and interaction), and Information Technologies (specifications of data and requirements of advanced DER interaction) subgroups. For Tasks 2, 3, 4, and 5.