The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-75-B November 24, 2021

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

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ORDER ON PROVISIONAL SYSTEM PLANNING PROGRAM

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I. INTRODUCTION AND BACKGROUND

A. Introduction

In this Order, the Department of Public Utilities ("Department") addresses the first phase of its investigation into improving distributed energy resource planning furthering the Commonwealth's progress towards achieving net-zero greenhouse gas emissions consistent with An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy, Acts of 2021, c. 8 ("Climate Act") and the Massachusetts 2050 Decarbonization Roadmap.[1] Through this proceeding, the Department is assessing optimal solutions for the interconnection of distributed generation ("DG")[2] facilities taking a long-term planning perspective. D.P.U. 20-75, at 2. It is critical to explore methods and policies that enhance our electric power system ("EPS") as we meet the goals of the Climate Act while ensuring a safe and reliable electric distribution system. In this order, the Department is examining policies to facilitate the deployment of properly sited DG that provides benefits to the EPS and customers. Currently, a DG facility whose interconnection triggers the need for an upgrade of the EPS is responsible for the full cost of that upgrade. These upgrades can be expensive and require extensive system planning, as well as significant time to construct. However, once the EPS has been upgraded, if properly designed, it may allow

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1 https://www.mass.gov/info-details/ma-decarbonization-roadmap.

2 For the purposes of this Order, the Department intends the term DG to refer to any type of facility that must submit an application under a Distribution Company's Standards for the Interconnection of Distributed Generation Tariff, regardless of whether the interconnecting facility actually generates electricity. These facilities include certain types of solar and energy storage systems.

for future DG projects to interconnect without further upgrades to the EPS. In this Order, the Department establishes a new, provisional framework for planning and funding essential upgrades to the EPS to foster timely and cost-effective development and interconnection of DG. While the Department continues to investigate a long-term framework, the provisional approach provides a pathway for many solar and energy storage system ("ESS") projects currently in the interconnection queue that may not be able to move forward due to significantly higher than historical interconnection costs. The provisional framework allows the electric distribution companies ("Distribution Companies")[3] to file certain EPS infrastructure upgrade proposals with the Department that limit the interconnection costs allocated to these DG facilities. Under the provisional design, customers will help fund the initial construction of these EPS upgrades but to balance this upfront cost, customers will be reimbursed over time from fees charged to future DG facilities that are able to interconnect due to the prior upgrades. This new pathway should help facilitate an equitable allocation of costs and remove barriers to the Commonwealth's progress to a clean energy future.

B. Background

On October 22, 2020, the Department opened this inquiry, pursuant to its ratemaking authority under G.L. c. 164, § 94 and its superintendence authority under G.L. c. 164, § 76, to investigate Distribution Companies' (1) distributed energy resource planning and

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[3] The Distribution Companies are Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), NSTAR Electric Company d/b/a Eversource Energy ("Eversource"), and Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid ("National Grid").

(2) assignment and recovery of costs for the interconnection of DG to a Distribution Company's EPS[4]. Distributed Energy Resource Planning and Cost Assignment, D.P.U. 20-75 (2020). In opening this inquiry, the Department issued a straw proposal that outlined distributed energy resource ("DER") planning requirements, a modified cost allocation methodology for both Interconnecting Customers[5] and ratepayers, and possible common system modification fee structures for different types of facilities ("Straw Proposal"). D.P.U. 20-75, Att. A.[6] The Department has received initial and reply

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4 The term "Company EPS" means the electric power system owned, controlled, or operated by the Distribution Company to provide distribution service to its customers. Standards for Interconnection of Distributed Generation Tariff ("DG Interconnection Tariff"), § 1.2 (Definitions).

5 The term "Interconnecting Customer" means the entity that owns and/or operates the DG facility proposing to interconnect or interconnected to a Distribution Company's EPS, with legal authority to enter into agreements regarding the construction or operation of the facility. DG Interconnection Tariff, § 1.2 (Definitions).

6 In Distributed Generation Interconnection, D.P.U. 19-55, in response to the Department's solicitation, stakeholders submitted several proposals with modifications to the current cost allocation methodology for interconnecting DG. The Department identified two proposals for further investigation and sought detailed proposals that could be implemented in the near term:

1. a proposal for residential and small commercial DG facilities that have historically not been required to pay for infrastructure modifications; and

2. a proposal for medium and large DG facilities that are subject to the current cost allocation methodology for interconnecting DG.

D.P.U. 19-55, Hearing Officer Procedural Memorandum at 3-4 (December 26, 2019).

On February 28, 2020, in D.P.U. 19-55, the Department received proposals for cost assignment and cost recovery from: (1) National Grid, (2) Eversource Energy, (3) the Department of Energy Resources, (4) the Attorney General of the Commonwealth of Massachusetts, (5) the Northeast Clean Energy Council, and comments from stakeholders, issued three sets of information requests to the Distribution Companies, and issued two sets of information requests to the non-distribution company stakeholders[7] in this proceeding.[8] In addition, the Department held a technical conference on June 3, 2021 and issued an Order on Interconnection Service Agreement Timeline.[9]

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(6) Pope Energy. On April 30, 2020, the Department held a virtual technical conference and allowed for the entities that submitted modified cost allocation proposals to provide ten-minute presentations and for stakeholders and Department staff to ask questions following the presentations. The proposals submitted in D.P.U. 19-55 materially informed the Straw Proposal and were incorporated into this docket for background and reference. D.P.U. 20-75, at 4 n.7, Atts. B-1 through B-6.

[7] This docket is a Department investigation, not an adjudicatory proceeding. As such, there are no parties to this docket. The Department issued two sets of information requests to all non-distribution company interested stakeholders via the electronic distribution list for this proceeding. Responses to these information requests were voluntary. The following stakeholders submitted responses: the Attorney General, DOER; Northeast Clean Energy Council; Coalition for Community Solar Access; Solar Energy Industries Association; BlueHub Capital Inc.; BlueWave Solar; Borrego Solar Systems, Inc.; Catalyze; ConEd Clean Energy Businesses; CVE North America; Entero Energy; Florence Electric, LLC; Galehead Development; Hexagon Energy; Interstate Renewable Energy Council, Inc.; Ironwood Renewables, LLC; Longroad Energy; MassSolar; Nexamp, Inc.; NextGrid Inc.; Parallel Products Solar Energy, LLC; Pope Energy; Renewable Energy Development Partners, LLC; ReWild Renewables; Seal Rock Energy; Solar Energy Business Association of New England; SunConnect Corporation; SunRaise Investments; Syncarpha Capital, LLC; TJA Clean Energy, LLC; and Zero-Point Development, Inc.

[8] On its own motion, the Department admits into the record as Exhibits the responses to information requests. The Exhibits and the Comments are listed on Attachment B to this Order. The Department finds that the record, the comments, and the Straw Proposal provide an adequate basis to address the matter of a Provisional System Planning Program without the need for an evidentiary hearing. For purposes of this proceeding, the Department considers the responses to information requests to be accurate and authentic

[9] To allow for consideration of a provisional system planning program, the Department extended the period for the members of specific identified group studies to notify

Based on information received from stakeholders in D.P.U. 19-55, in this docket, and through regular stakeholder engagement, the Department understands that there is a significant amount of DG in Eversource's and National Grid's respective interconnection queues that likely will withdraw from the interconnection process prior to executing an interconnection service agreement ("ISA") due to anticipated high interconnection costs under the currently applied cost causation principle.[10, 11] As such, the Department has identified three discrete topics for its investigation in this docket:

Eversource of the group study member's intention to proceed through the remainder of the interconnection process. D.P.U. 20-75-A at 6 (May 21, 2021).

10 In setting rates for utility service and otherwise providing for the recovery of costs by utilities, the Department applies the basic principle of cost causation; that is, the entity responsible for the cost to be incurred is responsible for payment of the costs (cost responsibility follows cost incurrence) ("Cost Causation Principle"). See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 167 (2009); Gas Unbundling, D.T.E. 98-32-B at 31 (1999); Boston Gas Company, D.P.U. 96-50 (Phase I), at 133-134 (1996); Electric Industry Restructuring, D.P.U. 96-100, at 51 (1996); Boston Gas Company, D.P.U. 93-60, at 331-337, 410, 432 (1993); Boston Edison Company, D. P. U. 1720, at 114 (1984); Generic Investigation of Rate Structures, D.P.U. 18810, at 14 (1977). In instances of public policy or where other discernable beneficiaries are identified, costs might be assigned and recovered from ratepayers other than just the entity responsible for the cost.

For the interconnection of DG, an interconnecting customer pays a Distribution Company for certain user fees and for system modification costs. DG Interconnection Tariff, §§ 3.10 (Table 6), 5.0; see also, Distributed Generation, D.T.E. 02-38-B (2004).

11 Unitil states that it does not have any applications or groups of applications that are expected to be presented with interconnection costs in the next year that are significantly higher than historic costs presented to interconnecting customers (Exh. EDC-1 (Unitil) at 1).

(1) Whether the Department should establish a long-term system planning program to include DER planning requirements and common system modification fees;

(2) If the Department establishes a long-term system planning program, what are the key elements of the Distribution Companies' system planning analysis to develop capital investment project proposals; and

(3) Whether the Department should establish a provisional system planning program ("Provisional Program") to address imminent DG interconnection concerns.

This Order addresses the third topic.

C. Summary of Department Straw Proposal

As part of the Order opening this investigation, the Department put forth a detailed Straw Proposal that outlines a modified cost allocation methodology for interconnecting DER. In addition, the Straw Proposal would require each Distribution Company to perform proactive distribution system planning for the assessment of interconnection and integration of DER. D.P.U. 20-75, Att. A at 3-5. More specifically, under the Straw Proposal, each Distribution Company would perform a rolling ten-year assessment of its EPS on an annual basis and would propose capital investment projects ("CIPs")[12] that would be eligible for

12 CIP is defined in the Straw Proposal as "a project proposed for cost recovery by a Distribution Company under the proposed distribution system planning process for the assessment of the interconnection and integration of DG, as described further below in Section II." D.P.U. 20-75, Att. A at 1. The Department further clarified that CIPs "may include but are not necessarily 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." D.P.U. 20-75, Att. A at 5 n.2.

consideration of cost recovery through a Reconciling Charge[13] and CIP Fees.[14] D.P.U. 20-75, Att. A at 4-5. Below, the Department examines relevant aspects of the Straw Proposal for inclusion in a Provisional Program.

Under the Straw Proposal, the Distribution Companies would submit CIPs for Department review and approval. If the Department approves a CIP, the Distribution Company would then construct the CIP and recover the costs of construction from distribution customers via a new Reconciling Charge. D.P.U. 20-75, Att. A at 6. This charge would be structured as a non-bypassable volumetric Reconciling Charge, which would be allocated to rate classes by revenue allocator and would be included as part of the distribution charge. D.P.U. 20-75, Att. A at 6-7. Additionally, there would be an annual rate cap under which the annual change in a Distribution Company's revenue requirement under the Provisional Program[15] would not exceed one and one-half percent of the

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13 Reconciling Charge is defined in the Straw Proposal "as the non-bypassable volumetric dollar-per-kilowatt-hour ("kWh") charge assessed to all ratepayers to cover the costs of a Distribution Company's Capital Investment Projects that are pre-approved by the Department, and which is offset by the collection of Capital Investment Project Fees from Interconnecting Customers." D.P.U. 20-75, Att. A at 3.

14 CIP Fee is defined in the Straw Proposal as "a fee that would be assessed by a Distribution Company to an Interconnecting Customer associated with its Facility's pro-rata share of the costs of a Capital Investment Project, which has been approved by the Department and of which the Interconnecting Customer's Facility is a direct beneficiary, as described further in Section II.B." D.P.U. 20-75, Att. A at 1.

15 Revenue Requirement is defined in the Straw Proposal as "depreciation, property tax, allowance for funds used during construction, and return associated with the system upgrade capital investment." D.P.U. 20-75, Att. A at 7.

Distribution Company's intrastate operating revenues recorded during the calendar year or a greater amount determined by the Department.[16] D.P.U. 20-75, Att. A, at 7.

In addition to providing for the recovery of costs from distribution customers via the Reconciling Charge, the Straw Proposal provides for the assessment of CIP Fees on interconnecting customers that would be able to interconnect to the EPS because of the capacity enabled by a CIP. D.P.U. 20-75, Att. A at 6. These fees would be assessed to an interconnecting customer based on the interconnecting facility's pro-rata share of the cost of the CIP(s) that allows it to interconnect. D.P.U. 20-75, Att. A at 6.[17] Under this proposed structure, CIP Fees would offset the upfront costs borne by distribution customers through the Reconciling Charge, and, over time, the CIP Fees paid by interconnecting customers would result in distribution customers' effectively being refunded for the initial costs associated with the CIPs.[18] D.P.U. 20-75, Att. A at 6.

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16 For purposes of the Provisional System Planning Program approved herein and the calculation of the annual rate cap, the Department adopts the use of "intrastate operating revenues" rather than "total operating revenue" as was provided in the Straw Proposal.

17 Pro rata share would be calculated based on the DG facility's size ($/kW).

18 Under the Straw Proposal, if all of the DG capacity enabled by a CIP interconnects to the EPS during the period of time designated for cost recovery, distribution customers would be fully refunded for the cost of the CIP.

D. Summary of Information Request Responses[19]

1. Distribution Companies

a. National Grid

National Grid states that groups of Interconnecting Customers[20] in Central and Western Massachusetts are likely to be presented with interconnection costs in the next year and a half that are significantly higher than those that have been historically presented, continuing the recent trend of increasing interconnection costs (Exh. EDC-1 (National Grid) at 2). [21] National Grid states that the preferred distribution infrastructure solutions for a

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[19] In order to obtain information and comments necessary to inform the development of the Provisional Program, the Department issued information requests in this docket specific to the Provisional Program: three sets to the Distribution Companies (EDC-1 through EDC-5; EDC-2-1 through EDC-2-6; EDC-3-1 through EDC-3-10) and two sets to the non-Distribution-Company stakeholders (Stakeholder-1-1 through Stakeholder-1-5; Stakeholders-2-1 through Stakeholders-2-3).

[20] These groups of interconnecting customers are part of group distribution system impact studies pursuant to DG Interconnection Tariff, § 3.4.1 ("Group Study"). The Department directed all Distribution Companies to include group study provisions in the DG Interconnection Tariff. Revisions to Section 3.4.1 of the Standards of Interconnection of Distributed Generation Tariff, D.P.U 17-164 (2020). Group Study allows the impact studies of two or more proposed DG facilities—by the same or different Interconnecting Customer(s)—in a common study area to be performed at the same time, instead of each application undergoing such study separately. The DG Interconnection Tariffs are: Fitchburg Gas and Electric Light Company d/b/a Unitil, M.D.P.U. No. 375; Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, M.D.P.U. No. 1468; and NSTAR Electric Company d/b/a Eversource Energy, M.D.P.U. No. 55A.

[21] National Grid identifies the following Group Studies: (1) Ayer-Clinton; (2) Barre-Athol; (3) Gardner-Winchendon; (4) Millbury-Grafton; (5) MPL-East; (6) MPL-Northwest; (7) Shutesbury; (8) Spencer-Rutland; and (9) Webster-Southbridge-Charlton (Exh. EDC-1 (National Grid) at 2-3).

Group Study must be sufficiently developed to identify DG and load injection points to the transmission system (Exh. EDC-1 (National Grid) at 3). National Grid suggests that utilities need to think beyond historical standard interconnection requirement concepts, as these resources will become critical factors in the stability and reliability of the future distribution and transmission electric systems (Exh. EDC-1 (National Grid) at 9). National Grid claims that, in recognition of mutual benefits to ratepayers and the Commonwealth, up to 40 to 60 percent of the EPS costs required to interconnect facilities that are part of the current Group Studies should be allocated as system benefits to all customers and recovered through the Reconciling Charge discussed in the Straw Proposal (Exhs. EDC-1 (National Grid) at 9; EDC-3-2 (National Grid) at 1-2).

National Grid estimates that $400 per kilowatt ("kW") is the threshold at or below which Interconnecting Customers historically have agreed to pay to interconnect (Exh. EDC-3 (National Grid) at 1). National Grid further states that dollar-per-kW is only one indicator of DG project viability and Interconnecting Customers may pay more than $400 per kW depending on the value that they place on other factors (Exh. EDC-3 (National Grid) at 1). National Grid notes that the viability of a DG project depends not only on interconnection cost but also on other factors, such as installation cost, land cost, permitting cost, and incentives (Exh. EDC-3 (National Grid) at 1). National Grid proposes that development of the Provisional Program occur before Group Study participants are presented with an ISA so that any proposed CIP Fees that the Department approves can be included in the applicable ISAs (Exh. EDC-4 (National Grid) at 1).

National Grid estimates that construction for the DG Facilities in the Group Studies will be complete by 2027, but notes that these high-level planning estimates do not take into consideration any external factors outside the Company's control or other non-EPS limiting factors that could affect those timelines, such as available land suitable for DG development in the area and permitting issues, supply chain constraints and customer delays (Exh. EDC-1(c) (National Grid) at 6).

National Grid proposed allocating 40 to 60 percent of "Substation Costs" to all electric distribution customers based on (a) a preliminary review of the potential multi-value benefits associated with asset condition, reliability, and system capacity and performance for the anticipated scope of work associated with its Central/Western Massachusetts Group Studies and (b) a high level estimate of the relative benefits that DG Interconnecting Customers and all electric distribution customers would receive from such work (Exh. EDC-3-2 (National Grid) at 1).

National Grid adds that if a system upgrade would benefit specific Interconnecting Customers, National Grid would propose a CIP Fee if it was warranted (Exh. EDC-3-2 (National Grid) at 2). When determining whether a specific EPS upgrade should be allocated exclusively to electric distribution customers versus offset by CIP Fees paid by Interconnecting Customers, National Grid's considerations would include (i) whether a specific EPS upgrade would address multiple system drivers, such as asset condition, reliability, and system capacity and performance, in addition to state climate goals and DER enablement, or (ii) whether the EPS upgrade would benefit only specific Interconnecting

Customers (Exh. EDC-3-2 (National Grid) at 3). National Grid suggests that any unpaid CIP Fee portion payable by future DG Interconnecting Customers in that area during the term set by the Department also would be paid through the Reconciling Charge as a revenue requirement until such time as a future DG Interconnecting Customer paid the associated CIP Fee to connect in that area (Exh. EDC-3-4 (National Grid) at 2).

In addition to its proposals for distribution upgrade cost recovery, National Grid proposes to recover 100 percent of costs associated with transmission line upgrades through the appropriate transmission rate approved by the Federal Energy Regulatory Commission (Exh. EDC-3-4 (National Grid) at 1). National Grid proposes to recover costs for equipment owned by New England Power Company[22] inside a substation proportionally between Interconnecting Customers and all electric distribution customers according to the benefits received (Exh. EDC-3-4 (National Grid) at 1). Following completion of the Group Studies and the associated transmission system impact study, National Grid states it will identify the distribution system and transmission system upgrades required for each Group Study (Exh. EDC-3-2 (National Grid) at 2). National Grid estimates expected costs of transmission upgrades ranging from $61 per kW to $1,817 per kW (Exh. EDC-3-3 (National Grid) at 1, Table 1). National Grid states that this estimate range allocates the high-level estimated

[22] New England Power Company ("NEP") holds the New England transmission assets of its parent company National Grid USA. NEP provides transmission service to, among others, Massachusetts Electric Company and Nantucket Electric Company, which are affiliates within the National Grid USA holding company system.

transmission related dollar-per-kW costs per Group Study region consistent with the DG capacity in megawatts ("MW") per region (Exh. EDC-3-3 (National Grid) at 1).

b. Eversource

Eversource states that its expected interconnection costs are driven by the results of system impact studies that identify technical impacts and planning criteria violations at individual substations within the group once the Group Study DG facilities are added to existing substations (Exh. EDC-1 (Eversource) at 3). Similar to National Grid, Eversource demonstrates that Group Study participants in Southeastern and Western Massachusetts are likely to be presented with interconnection costs in the next year and a half that are significantly higher than those that have been historically presented to customers (Exhs. EDC-1 (Eversource) at 5; EDC-3 (Eversource) at 1).[23] According to Eversource, DG growth rate in certain areas, such as Southeastern Massachusetts, suggests that a more comprehensive solution is needed to integrate as much DG as possible and to allow Eversource to fully participate in supporting the Commonwealth's climate policy goals (Exh. EDC-1 (Eversource) at 3). Eversource suggests that the key to maintaining safe, reliable operation is preserving operational flexibility under all scenarios for which the system is planned and designed to accommodate (Exh. EDC-1 (Eversource) at 9). Eversource notes that the capacity released by EPS upgrades allows the company to maintain its operational standards despite the challenges presented by DG (Exh. EDC-1 (Eversource)

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23 Eversource identifies the following Group Studies: (1) Marion-Fairhaven; (2) Plymouth; (3) Cape Cod; (4) Freetown; (5) Dartmouth-Westport; (6) New Bedford; and (7) Plainfield-Blandford (Exh. EDC-1 (Eversource) at 2).

at 10). Furthermore, Eversource explains that new distribution lines and line upgrades are likely to create opportunities to rebalance feeders, reduce exposure, and transfer load, which would lead to improved reliability and voltage quality for ratepayers (Exh. EDC-1 (Eversource) at 10). Eversource further states that utilities faced with significant DER growth, without the ability to address these types of conditions, could experience reliability deficiencies in the near-term when low DER saturated areas progress to medium or high saturation when the saturation is left unaddressed (Exh. EDC-1 (Eversource) at 13).

Eversource provided a high-level construction schedule for Group Study system upgrades that range from 2022 to 2026 based on historical estimates for similar work and that does not reflect any site-specific factors likely to impact the actual schedule (Exh. EDC-1(c) (Eversource) at 8, Table 6). With respect to interconnection costs that customers may be able to bear, Eversource demonstrates that the vast majority of Interconnecting Customers have historically paid less than $500 per kW (Exh. EDC-3 (Eversource) at 1).

Eversource agrees with National Grid that some system upgrades will have shared system uses and that mutual benefits should be reflected in the costs ultimately allocated to interconnecting DG facilities (Exh. EDC-2-3 (Eversource) at 1). Eversource claims that substation and transmission assets will likely provide progressively higher parallel benefits to the operation of the EPS (Exh. EDC-2-3 (Eversource) at 1). Eversource proposes to assess shared system uses and to allocate costs based upon localized system conditions and upgrades instead of applying a standard cost allocation ratio (Exh. EDC-2-3 (Eversource) at 1). Eversource states that a cost allocation methodology that produces outliers incentivizes efficient distribution infrastructure buildout and provides an interconnection price signal to develop DG where infrastructure has already been built to higher capacity and can reliably integrate DG (Exh. EDC-2-3 (Eversource) at 2). Eversource contends that applying a standard allocation ratio to system upgrade costs risks placing other customers in a position of funding investments that do not produce mutual benefits (Exh. EDC-2-3 (Eversource) at 2). According to Eversource this standard allocation also risks reducing incentives for DG facilities to locate on portions of the EPS where infrastructure that produces parallel benefits also enables the interconnection of DG (Exh. EDC-2-3 (Eversource) at 2).

Eversource states that because all customers benefit from upgrades that enable DER and increase operational flexibility and reliability, the Company would allocate costs among Interconnecting Customers through CIP Fees and distribution customers through the Reconciling Charge in proportion to the ratio of enabled DER capacity/planned connected capacity and operational capacity/planned connected capacity respectively (Exh. EDC-3-1 (Eversource) at 3). Eversource expects that upgrades completed through a Provisional Program will enable DER capacity that exceeds the total capacity of DER facilities currently in the interconnection queue (Exh. EDC-3-5 (Eversource) at 2).

Eversource proposes to allocate 100 percent of transmission costs to rate base (Exh. EDC-3-1(b) (Eversource) at 3). Eversource argues that precisely dissecting the costs and benefits for all Interconnecting Customers, local transmission customers, distribution customers, and transmission connected generators is a protracted and impractical process (Exh. EDC-3-1(b) (Eversource) at 3). Eversource states that, to the extent it is unable to recover the costs and ensure appropriate cost allocation to Massachusetts customers through existing local network service transmission tariffs, Eversource would seek cost recovery for these upgrades from its distribution customers through an appropriate alternative mechanism (Exh. EDC-3-4 (Eversource) at 1). Eversource expects that a modified cost recovery mechanism could be accomplished by establishing a regulatory asset to recover these transmission provisional system planning program costs from distribution customers (Exh. EDC-3-4 (Eversource) at 1).

c. Unitil

Unitil does not have any applications or groups of applications that are expected to be presented with interconnection costs in the next one and a half years that are significantly higher than historic costs presented to Interconnecting Customers (Exh. EDC-1 (Unitil) at 1). Unitil notes that it does not currently have any expectations that there will be a need for significant EPS upgrades as a result of DG facilities seeking to interconnect, but that if it were to receive applications for large DG facilities in the next year it could trigger a need to study whether such upgrades are required (Exh. EDC-1 (Unitil) at 1). Unitil notes that Interconnecting Customers have historically paid for system modifications in an amount up to $750 per kW (Exh. EDC-3 (Unitil) at 1). Unitil generally agrees with National Grid's proposal to allocate up to 40 to 60 percent of the DG interconnection costs as system benefits to all customers, though Unitil notes that certain benefits are transmission specific (Exh. EDC-2-6 (Unitil) at 1). Unitil had not, at the time of its response, conducted an analysis of the percentage of DG interconnection costs that should be allocated as system benefits to all customers on its system (Exh. EDC-2-6 (Unitil) at 1).

2. Non-Distribution Company Stakeholders

a. Department of Energy Resources

The Department of Energy Resources ("DOER") supports assigning costs to those who benefit and states that asset lifespan should be evaluated and quantified when making an allocation decision (Exh. Stakeholders-2-1 (DOER) at 1). DOER suggests that the Department should require the Distribution Companies to adopt a standard set of benefits for allocating costs between Interconnecting Customers and all other customers, with a detailed quantification of these benefits to support cost allocation decisions (Exh. Stakeholders-2-1 (DOER) at 1).

Additionally, DOER encourages the Department to consider the cost impacts on customers and the implications on electrification[24] (DOER Reply Comments at 2 (June 8, 2021)). DOER also recommends that the Department consider potential safeguards such as limiting total cost impacts allowable within the provisional approvals, limiting eligibility only to CIPs that could construct on a relatively near timeframe, and/or limit eligibility only to

24 Electrification refers to the process of replacing technologies that use fossil fuels with technologies that use electricity as a source of energy. The Commonwealth has statewide goals of achieving net zero greenhouse gas emissions in 2050. The Massachusetts Governor and the state legislature have recognized the importance of electrification in achieving this goal. Executive Order No. 594: Leading by Example: Decarbonizing and Minimizing Environmental Impacts of State Government (April 22, 2021); An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, Acts of 2021, c. 8.

CIPs that demonstrate specific broad ratepayer benefits in the Provisional Program to ensure ratepayer benefits are maximized (DOER Reply Comments at 2 (June 8, 2021)). DOER states that Distribution Companies should allocate costs according to the contribution to the need for an upgrade (DOER Reply Comments at 2 (June 8, 2021)). Further, DOER states that energy storage system CIP Fees should be established based upon the system's capacity contribution during the hours of system analysis that resulted in the need for the upgrade (DOER Reply Comments at 2 (June 8, 2021)). DOER suggests that the Department require the Distribution Companies to provide additional information about future infrastructure investment needs beyond the Provisional Program and to consider investments more holistically (DOER Reply Comments at 3 (June 8, 2021)). DOER notes that it raised the need to defer and mitigate infrastructure investments as a central point in comments submitted in this docket and specifically highlights that the deployment of a distributed energy management system will be important in the future to support maximizing the amount of DG that may contribute to CIPs (DOER Reply Comments at 3 (June 8, 2021); DOER Initial Comments (December 23, 2020)).

b. Attorney General

Regarding National Grid's proposal to allocate a percentage of the DG interconnection costs as system benefits to all customers, the Attorney General for the Commonwealth of Massachusetts ("Attorney General") states that additional information is necessary to determine what shared benefits will be delivered, how these benefits are captured already either by grid modernization plans or by performance-based ratemaking, and what value ratepayers should contribute (Exh. Stakeholders-2-1 (Attorney General) at 1). The Attorney General maintains that National Grid fails to explain the impacts that DG facilities will have in areas of anticipated load growth (Exh. Stakeholders-2-1 (Attorney General) at 1). The Attorney General contends that National Grid's proposal fails to address the alternatives that could be employed to produce benefits and address load growth from building a nimbler distribution grid with these facilities (Exh. Stakeholders-2-1 (Attorney General) at 1). The Attorney General concludes that National Grid's proposal falls short of providing for the full consideration of alternatives, the true nature of benefits to be gained, and the calculation of the 40 percent itself and, therefore, she requests further Department process in establishing this cost share before imposing this type of expense on ratepayers (Exh. Stakeholders-2-1 (Attorney General) at 1-2).

The Attorney General asserts that a full adjudicatory proceeding is necessary to review Distribution Companies' CIPs, because the effort to fund such a program is new and will be costly to all involved (Exh. Stakeholders-2-2 (Attorney General) at 1). The Attorney General states that such a proceeding likely would take nine months or longer from filing to decision but, in recognition of the time pressures on stranded projects, the Department should consider the procedural schedule of the gas system enhancement plan ("GSEP") and GSEP reconciliation ("GREC") petitions[25] (Exh. Stakeholders-2-2 (Attorney General) at 1).

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[25] Gas distribution companies file their respective GSEPs annually for approval from the Department. The GSEPs set forth a plan for the replacement of aging and leak-prone natural gas pipeline infrastructure and establish a charge for the recovery of estimated GSEP-related costs. G.L. c. 164, §§ 145(a), (b), (c), (e). Gas distribution companies also file a GREC petition annually to, in part, establish a reconciling charge through

The Attorney General further notes that a 40 to 60-percent ratepayer share of responsibility for interconnection costs could be understated if more of the excess capacity is taken by Distribution Company-sponsored projects rather than developer-driven projects that otherwise would contribute through a CIP (Attorney General Reply Comments at 1-2 (June 8, 2021)). The Attorney General urges the Department to seek clarity from the Distribution Companies on how the Climate Act's allowance of hundreds of MW of new utility-owned solar intersects with the Provisional Program and impacts ratepayer expenses (Attorney General Reply Comments at 2 (June 8, 2021)).

c. Northeast Clean Energy Council, Coalition for Community Solar Access, and Solar Energy Industries Association

Northeast Clean Energy Council ("NECEC"), Coalition for Community Solar Access ("CCSA"), and Solar Energy Industries Association ("SEIA") express their concern about the viability of projects within the Group Studies identified by National Grid and Eversource because of the costs likely allocated to each project, the timelines associated with interconnecting projects, and the uncertainty around both costs and timelines (Exh. Stakeholder-1 (NECEC, CCSA, SEIA) at 1). NECEC, CCSA, and SEIA state that there is an urgent need to deliver viable pathways for currently proposed projects and to

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which the gas distribution companies recover or reimburse ratepayers for the difference between their estimated and actual GSEP-related costs as approved by the Department. G.L. c. 164, § 145(g). Each gas distribution company files its annual GSEP on October 31 for the following construction year; the Department reviews the GSEP for approval, modification, or disapproval within six months of filing. G.L. c. 164, § 145(d). Each gas distribution company files its proposed GREC factors on May 1; the Department investigates the GREC factors within six months of filing. G.L. c. 164, § 145(f).

establish an enduring, equitable strategy over the longer-term (Exh. Stakeholder-1 (NECEC, CCSA, SEIA) at 1).

NECEC, CCSA, and SEIA contend that interconnection costs of thousands of dollars-per-kW are not economically viable in Massachusetts and reinforce the need for a dramatic change in cost allocation methodology for currently proposed projects in Group Study to have any chance of economic viability (Exh. Stakeholder-2 (NECEC, CCSA, SEIA) at 2). The members of NECEC and CCSA generally agree that the level of interconnection costs that would result from the proposed cost allocation methodologies of the Department and the Distribution Companies still may be cost prohibitive and may adversely impact the continued successful development and deployment of DERs consistent with the Commonwealth's overall policy objectives (Exh. Stakeholders-2-1 (NECEC, CCSA) at 1-2). NECEC, CCSA, and SEIA suggest that the Distribution Companies should redouble their efforts to reduce EPS upgrade construction timelines considerably through advancing procurement, permitting, and design planning using creative construction strategies, including allowing experienced developers to perform the construction process to Distribution Company specifications to accelerate timetables, improve efficiency, and maintain high construction standards (Exh. Stakeholder-3 (NECEC, CCSA, SEIA) at 4). NECEC, CCSA, and SEIA conclude that the Department should move forward with an immediate reform to cost sharing for upgrades to the EPS systems subject to its jurisdiction (Exh. Stakeholder-5 (NECEC, CCSA, SEIA) at 7).

NECEC and CCSA generally agree with the principles underlying National Grid's allocation proposal and express their support for substantial cost allocation to all distribution customers in recognition of the broad benefits that system modifications deliver (Exh. Stakeholders-2-1 (NECEC, CCSA) at 1). NECEC and CCSA contend that these benefits include, but are not limited to, increased reliability and resilience, the replacement of aging equipment, the interconnection of clean energy resources that support the overall clean energy and climate goals of the Commonwealth, and pollution reduction (Exh. Stakeholders-2-1 (NECEC, CCSA) at 1). NECEC and CCSA support allocating all transmission modification costs to all distribution customers to reflect the broad benefits that transmission upgrades will deliver (Exh. Stakeholders-2-1 (NECEC, CCSA) at 1). NECEC and CCSA suggest that some five-MW projects may, under optimal circumstances, be able to bear costs that approach $300/kW but maintain that smaller projects face different economics such that the Department should consider instituting a sliding scale to cap interconnection costs at a level that continues to send an economic signal to developers and allows projects to move forward (Exh. Stakeholders-2-1 (NECEC, CCSA) at 1). NECEC suggests the Department revisit its proposal which assigns no more than 30 percent or $300 per kilowatt of shared distribution costs to DER[26] (Exh. Stakeholders-2-1 (NECEC, CCSA) at 2). NECEC and CCSA suggest that the estimates provided by Eversource and National Grid

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[26] NextGrid Inc, Zero-Point Development, SunRaise Investments and ReWild Renewables support NECEC's original cost allocation proposal (Stakeholders-2-1 (NextGrid Inc) at 1; Stakeholders-2-1 (Zero-Point Development) at 2; Stakeholders-2-1 (SunRaise Investments and ReWild Renewables) at 1).

regarding the cost of Group Study-based upgrades or comprehensive system planning-based to be allocated to DERs clearly show that the scope of upgrades and the resulting costs greatly exceed historical financially viable interconnection cost levels (Exh. Stakeholders-2-1 (NECEC, CCSA) at 2). NECEC and CCSA note that decisions to move forward with interconnection are likely to be project specific and dependent on a variety of factors including continued development expenses, landowner and customer commitments, and forecasted costs and timelines to interconnect (Exh. Stakeholder-2-3 (NECEC, CCSA) at 5).

NECEC and CCSA recommend that the Department direct each Distribution Company to make its CIP proposals under a Provisional Program simultaneously with the completion of Group Study results to accelerate review of each proposal (Exh. Stakeholder-2-2 (NECEC, CCSA) at 3). NECEC and CCSA suggest that the Department consider establishing the template, form, and content of the CIPs to accelerate the review of the proposals by the stakeholders impacted by a particular proposal (Exh. Stakeholder 2-2 (NECEC, CCSA) at 3).

d. Additional Non-Distribution Company Solar Stakeholders

Many non-Distribution Company solar stakeholders ("Solar Stakeholders") currently have a DG facility in the interconnection queue within one of the Distribution Companies' Group Studies (Exhs. Stakeholder-1 (BlueWave Solar) at 2; Stakeholder-1 (Borrego Solar Systems) at 1-2; Stakeholder-1 (Catalyze) at 1; Stakeholder-1 (ConEd) at 3; Stakeholder-1 (CVE North America) at 1; Stakeholder-1 (Entero Energy) at 1; Stakeholder-1 (Galehead Development) at 1; Stakeholder-1 (Hexagon Energy) at 1; Stakeholder-1 (Ironwood Renewables) at 1; Stakeholder-1 (Longroad Energy) at 2; Stakeholder-1 (Nexamp) at 1;

Stakeholder-1 (NextGrid) at 1; Stakeholder-1 (Parallel Products) at 2; Stakeholder-1 (Pope Energy) at 2; Stakeholder-1 (Renewable Energy Development Partners) at 1; Stakeholder-1 (Seal Rock Energy) at 1; Stakeholder-1 (SunConnect) at 1; Stakeholder-1 (SunRaise Investments and ReWild Renewables) at 1-2; Stakeholder-1 (Syncarpha Capital) at 1; Stakeholder-1 (TJA Clean Energy) at 1-2; Stakeholder-1 (Zero-Point Development) at 2). Some Solar Stakeholders already have withdrawn DG projects due to interconnection costs and unfeasible timelines (Exhs. Stakeholder-1 (BlueHub Capital) at 1; Stakeholder-1 (Borrego Solar Systems) at 3; Stakeholder-1 (ConEd) at 3; Stakeholder-1 (Nexamp) at 1; Stakeholder-1 (SunRaise Investments and ReWild Renewables) at 1-2; Stakeholder-1 (Syncarpha Capital) at 1).

Many Solar Stakeholders indicated that the current cost allocation method for ESP upgrades will not allow DG projects to interconnect and, even if infrastructure costs are spread amongst current and future DG projects, costs are untenable (Exhs. Stakeholder-2 (BlueHub Capital) at 1; Stakeholder-2 (Borrego Solar) at 4; Stakeholder-2 (Catalyze) at 1; Stakeholder-2 (ConEd) at 3; Stakeholder-2 (CVE North America) at 2; Stakeholder-2 (Florence Electric) at 1-2; Stakeholder-2 (Hexagon Energy) at 1-2; Stakeholder-2 (Ironwood Renewables) at 1; Stakeholder-2 (Longroad Energy) at 2-3; Stakeholder-2 (Nexamp) at 1-2; Stakeholder-2 (NextGrid) at 2; Stakeholder-2 (Parallel Products) at 2-3; Stakeholder-2 (Seal Rock Energy) at 1-2; Stakeholder-2 (SunConnect) at 1-2; Stakeholder-2 (SunRaise Investments and ReWild Renewables) at 2-3; Stakeholder-2 (Syncarpha Capital) at 1-2; Stakeholder-2 (TJA Clean Energy) at 3). Many of the Solar Stakeholders argue that the result of a Provisional Program should be a clear dollar-per-kW fee structure and a schedule that will enable DG projects to execute an ISA with a clear interconnection timeline (Exhs. Stakeholder-3 (Catalyze) at 2; Stakeholder-3 (CVE North America) at 2; Stakeholder-3 (Entero Energy) at 1-2; Stakeholder-3 (Florence Electric) at 2; Stakeholder-3 (Galehead Development) at 2; Stakeholder-3 (Hexagon Energy) at 3; Stakeholder-3 (Ironwood Renewables) at 2; Stakeholder-3 (Longroad Energy) at 3; Stakeholder-2 (NextGrid) at 2-3; Stakeholder-3 (Parallel Products) at 3; Stakeholder-3 (Seal Rock Energy) at 2; Stakeholder-3 (SunRaise Investments and ReWild Renewables) at 3; Stakeholder-3 (Syncarpha Capital) at 2; Stakeholder-3 (TJA Clean Energy) at 4).

The Solar Energy Business Association of New England ("SEBANE") encourages the Department to pursue a Provisional Program as a start to a revised approach to EPS planning that considers both the benefits and the costs to all stakeholders (SEBANE Reply Comments at 1-2 (June 8, 2021)). SEBANE notes that a reactionary approach to system upgrades will impede the attainment of the Commonwealth's clean energy and electrification goals (SEBANE Reply Comments at 2 (June 8, 2021)). SEBANE claims that a Provisional Program will install confidence in the DER industry, will demonstrate that the Department is serious about trying to alleviate the enormous strain of the current interconnection process for larger projects, keep developers engaged, reinvigorate growth in an industry that has been on the decline over the last several years, and help to meet the demand of ratepayers who are seeking DG solutions and clean energy options (SEBANE Reply Comments at 2 (June 8, 2021)).

II. ANALYSIS AND FINDINGS

A. Establishment of a Provisional Program

As part of this investigation, the Department is considering the establishment of a long-term system planning process to identify distribution system infrastructure investments, in particular, the interconnection of DG facilities to a Distribution Company's EPS, consistent with the Commonwealth's clean energy and climate policy objectives. If established, however, we expect that the process will take multiple years before the first system planning proposals are developed and submitted by the Distribution Companies and reviewed by the Department. Accordingly, in recognition of the unique and immediate challenges some DG facilities and the Distribution Companies are facing and the timing necessary to fully develop an appropriate long-term system planning process that is in the public interest, through this Order we establish a Provisional Program to address imminent short-term DG interconnection cost allocation concerns.

Eversource and National Grid anticipate assessing interconnection related EPS upgrade costs for a large portion of DG currently in the interconnection queue in the next year that will be significantly higher than average, historical interconnection costs (Exhs. EDC-1 (Eversource) at 5; EDC-3 (Eversource) at 1; EDC-1 (National Grid) at 2). Eversource and National Grid indicate that the impacted DG projects are part of current Group Studies ("Affected Group Studies")[27] (Exh. EDC-1(a) (Eversource); Exh. EDC-1(a) (National Grid)).

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[27] National Grid identifies the following Affected Group Studies: (1) Ayer-Clinton; (2) Barre-Athol; (3) Gardner-Winchendon; (4) Millbury-Grafton; (5) MPL-East; (6) MPL-Northwest; (7) Shutesbury; (8) Spencer-Rutland; and (9) Webster-Southbridge-

Eversource and National Grid will notify Affected Group Studies of system modification costs as they become available (Exhs. Eversource EDC-1 (Eversource) at 2; EDC-1 (National Grid)) at 2-3.

Furthermore, based on stakeholder feedback, the Department understands that there is almost a gigawatt ("GW") (1,000 MW) of DG in the Affected Group Studies and in Eversource's and National Grid's respective interconnection queues that likely will withdraw from the interconnection process prior to executing an ISA due to anticipated high interconnection costs[28] (Exhs. EDC-1(a) (Eversource); EDC-3 (Eversource); EDC-1(a) (National Grid); EDC-3 (National Grid); see also various Exhs. Stakeholder-2). These high costs likely will also make it difficult to interconnect any new DG facilities in the affected geographic regions until the necessary EPS upgrades are constructed.

The development of properly sited renewable energy facilities is vital to achieving the Commonwealth's greenhouse gas emissions targets and clean energy goals, and the Distribution Companies play a critical role in the interconnection of DG facilities in the advancement of these policies. The Commonwealth's Interim Clean Energy and Climate Plan ("Interim CECP") for 2030 estimates that the Commonwealth will need to develop

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Charlton (Exh. EDC-1 (National Grid) at 2-3). Eversource identifies the following Group Studies: (1) Marion-Fairhaven; (2) Plymouth; (3) Cape Cod; (4) Freetown; (5) Dartmouth-Westport; (6) New Bedford; and (7) Plainfield-Blandford (Exh. EDC-1 (Eversource) at 2).

28 Eversource has identified approximately 348 MW of DG facilities and National Grid has identified approximately 331 MW of DG facilities that are part of the Affected Group Studies and that may be appropriate for a Provisional Program (Exhs. EDC-1 (Eversource) at 2; EDC-1 (National Grid) at 2-3).

5.2 GW of additional solar capacity between 2021 and 2030 to stay on pace to achieve these goals.[29] Considering the Commonwealth's greenhouse gas reduction and clean energy policies, the Department finds that application of the traditional cost allocation approach to the anticipated high interconnection costs identified in this investigation will pose a significant barrier to short-term DG facility development and may deter future properly sited renewable energy facilities further frustrating the Commonwealth's clean energy objectives.

The Straw Proposal contemplates equitable cost sharing for Interconnecting Customers because the cost of some EPS system modifications (CIPs) would be shared by all Interconnecting Customers that benefit from an upgrade over a period of time. In consideration of a Provisional Program, we asked the Distribution Companies to provide estimates of costs for EPS upgrades associated with the Affected Group Studies, if those costs were allocated based on the Straw Proposal (Exhs. EDC-1(b) (Eversource); EDC-1(b) (National Grid); EDC-1(b) (Unitil); EDC-2 (Eversource); EDC-2 (National Grid); EDC-2 (Unitil)). We also asked the Distribution Companies and non-distribution company stakeholders to provide information on the likely maximum cost-per-kW that an Interconnecting Customer could pay and maintain DG project viability (Exhs. EDC-3 (Eversource); EDC-3 (National Grid); EDC-3 (Unitil)). Based on a comparison of the cost estimates provided by National Grid and Eversource and the estimates from the Distribution Companies and non-distribution company stakeholders of the maximum cost-per-kW to

29 Interim Clean Energy and Climate Plan for 2030, at 37 (December 30, 2020) (https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download).

maintain DG project viability, we find that a Provisional Program has the potential to facilitate viable interconnection for many of the DG facilities in the Affected Group Studies.

For these reasons, the Department finds that establishment of a Provisional Program with a modified cost allocation and cost recovery methodology is consistent with the public interest[30] and is warranted at this time.[31] Under the Provisional Program, CIPs must be based on the cost allocation and cost recovery methodology set forth in the Straw Proposal and must fulfill the additional requirements set forth below.[32]

The Department emphasizes that establishment of a Provisional Program does not mandate or pre-authorize any CIPs. The Department will review each CIP on a case-by-case basis and may approve, deny, or modify any proposal. The Department has a duty and obligation to protect the safety and reliability of the EPS and to ensure just and reasonable rates for all distribution customers. There are many complex issues to investigate before we

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30 The Department's mission is to regulate in the public interest. Zachs v. Department of Public Utilities, 406 Mass. 217, 223 (1989).

31 While the primary focus of this Order is facilitating the interconnection of DG facilities, the Department also notes that the distribution system investments necessary to achieve DG interconnections are also likely to help facilitate electrification of the transportation and building sectors, which are key components of the Commonwealth's plans for the short and long-term reduction of greenhouse gas emissions. Interim Clean Energy and Climate Plan for 2030, at 4-6 (December 30, 2020) (https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download). It is essential that utilities continue to take a long-term view to ensure long-term reliability for ratepayers given the complexities involved in siting and constructing prudent EPS investments, as well as the potential impacts of climate change.

32 The provisions and requirements of the Provisional Program are set forth in Attachment C to this Order.

determine whether a CIP will provide equitable costs and benefits to ratepayers and Interconnecting Customers. These issues include, but are not limited to: distribution versus transmission system upgrade costs; potential federal law implications; whether to allow any costs associated with DG interconnection to be considered common system benefits and allocated to all distribution customers; whether utility-owned solar will affect the success of certain proposed CIPs; and whether there is a likelihood that a sufficient amount of enabled DG capacity would be utilized in the geographical region of a CIP to mitigate risk of excess costs borne by distribution customers.

B. Expected Process, Deadlines, and Requirements CIP Proposals

Under the Provisional Program, the Distribution Companies proposed CIPs must be submitted to the Department for review consistent with process and requirements set forth below. In consideration of the timing concerns raised by stakeholders (see, e.g., Exhs. Stakeholder-2 (Nexamp) at 2; Stakeholder-2 (SEBANE and MassSolar); Stakeholder-2 (Galehead Development) at 1-2); Stakeholder-2 (BlueHub Capital) at 2), and the necessity of a fully developed CIP, the Department sets forth the following deadlines. Following the completion of a distribution and transmission (if applicable) impact study for Affected Group Studies, as detailed below, a Distribution Company must notify all Group Study members and the Department of study completion ("Completion Date") through a letter filed in D.P.U. 20-75.[33] A Distribution Company has ten business days from the Completion Date

[33] Where an impact study for any eligible Group Study has been completed prior to issuance of this Order, the Completion Date shall be the tenth business day following the date of this Order.

to determine if any EPS upgrades identified for a Group Study will be the subject of a CIP in the Provisional Program and to inform the Group Study members. If no upgrades will be submitted in a CIP, the current DG Interconnection Tariff timeline applies.[34] A Distribution Company shall have 40 business days from the Completion Date to file a CIP for Department review. A CIP shall consist of all eligible EPS upgrades identified for a single Group Study. Each proposal should be filed in a separate docket; however, the Department may review multiple proposals in one proceeding if it determines that such review is appropriate based on such factors as time of submission, geographical region, and factual similarities of the filings.

The Department will review CIPs through an adjudicatory proceeding. To facilitate an efficient and timely review, the Department strongly encourages the Distribution Companies to coordinate with each other, ISO-NE, and stakeholders to establish commonalities between their respective filings to help facilitate a more expedited review by the Department.

CIPs must include, at a minimum: (1) a description of the CIP, including projected cost, equipment, permitting and licensing requirements, and construction timeline; (2) a demonstration that the CIP meets all eligibility criteria, including those set forth in

[34] In the revised Group Study process under the DG Interconnection Tariff, upon completion of a Group Study, the Distribution Company presents the study results to the group and each group member has 15 days to determine whether it will proceed in the interconnection process ("Notice Period") (DG Interconnection Tariff, § 3.4.1(i)). The day that the Distribution Company provides notice of a determination that no EPS upgrades identified for the Group Study will be included in a CIP, will constitute the first day of the "Notice Period."

Section II.C below; (3) a detailed cost allocation proposal based on the Straw Proposal[35] that includes a proposed rate recovery period for the CIP through the Reconciling Charge;[36] (4) projected bill impacts; (5) a description of how the CIP will benefit ratepayers and aligns with cost-efficiently meeting the Commonwealth's clean energy policies; and (6) explanation of how the CIP will affect low-income and environmental justice populations, including describing any projects in the CIP that will be constructed in an environmental justice neighborhood.[37]

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35 Cost allocation proposals must include details on the differentiation between distribution and transmission EPS upgrade costs. The Department does not make a determination in this Order whether both distribution and transmission upgrade costs associated with a CIP will be eligible for the Provisional Program.

36 Under the Straw Proposal, the Department proposed that CIP fees associated with the costs of specific CIPs would be collected from interconnecting DG facilities for a period of ten years from Department pre-approval, after which any remaining costs would be collected from ratepayers via the Reconciling Charge. D.P.U. 20-75, Att. A, at 6. Here we do not set a time period for recovery under the Reconciling Charge for collection of costs from distribution customers or CIP Fees from interconnecting customers. Instead, we direct the Distribution Companies to propose a time period for rate recovery through the Reconciling Charge for each CIP proposal ("Rate Recovery Period").

37 "Environmental justice population" is defined as (A) a neighborhood that meets 1 or more of the following criteria: (i) the annual median household income is not more than 65 per cent of the statewide annual median household income; (ii) minorities comprise 40 per cent or more of the population; (iii) 25 per cent or more of households lack English language proficiency; or (iv) minorities comprise 25 per cent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 per cent of the statewide annual median household income; or (B) a geographic portion of a neighborhood designated by the Secretary as an environmental justice population in accordance with the law." Environmental Justice Policy of the Executive Office of Energy and Environmental Affairs at 4, available at https://www.mass.gov/service-details/environmental-justice-policy (June 24, 2021).

Regarding cost recovery for CIPs under the Provisional Program, the Department expects that a significant percentage of costs, if not all costs, initially borne by distribution customers via the Reconciling Charge will be offset through CIP fees collected from Interconnecting Customers (i.e., future entities interconnecting DG facilities). However, the Department is aware that the Distribution Companies have proposed that some EPS upgrade costs be fully paid by distribution customers and not offset via the collection of CIP fees from Interconnecting Customers; these upgrade costs are proposed for recovery through a combination of the Reconciling Charge and transmission charges (Exhs. EDC-2-3 (Eversource); EDC 3-1 (Eversource); EDC-3-4 (Eversource); EDC 3-2 (National Grid); EDC-3-4 (National Grid)). Upon review of the Distribution Companies' proposals, we find that there is insufficient information on the record in this matter to determine if any CIP costs should be borne exclusively by distribution customers through the Reconciling Charge. To determine whether it would be consistent with the public interest for any CIP costs to be borne solely by distribution customers and whether those costs should be recovered through a Reconciling Charge rather than base distribution rates, we must conduct an investigation with a full understanding of the details of a specific CIP. As such, we do not make a determination here on whether any CIP costs should be borne solely by distribution customers through the Reconciling Charge, but we will investigate CIPs that include such cost assignment proposals.[38] Furthermore, any Distribution Company that makes such a

[38] We recognize that expansion or modification of each Distribution Company's EPS may be necessary in the future to address climate adaptation and allow for further electrification and renewable energy consistent with the Commonwealth's clean energy

proposal shall provide: (a) detailed descriptions of each component of a CIP that it proposes to recover solely from ratepayers; and (b) a justification for why the costs of the CIP should be recovered from ratepayers and not from Interconnecting Customers.

C. Eligibility Criteria for CIPs

The Department recognizes that there are numerous overlapping DG programs and Commonwealth clean energy and climate policies that may be affected by a Provisional Program, such as the SMART Program,[39] net metering, participation in wholesale markets, and greenhouse gas emission limits. We also recognize that Interconnecting Customers desire regulatory certainty to secure financing and viability for their DG project. Simultaneously the Department must (a) protect ratepayer interests in the delivery of safe, reliable, cost-effective electric service and (b) advance the interconnection of DG in a manner that benefits the Commonwealth as a whole and improves the overall EPS reliability and resilience. As such, we have set forth eligibility criteria for CIPs to provide regulatory certainty and to prevent unnecessary delay and administrative burden for Interconnecting Customers whose interconnection trigger the need for EPS upgrades that are not appropriate

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and climate policies. The Provisional Program is not, however, the appropriate forum for such requests and the Distribution Companies must provide evidence to make the distinction between necessary investments to meet overall clean energy and climate goals and the limited purpose of CIPs that are necessary for a Provisional Program to achieve its objectives of supporting the interconnection of DG projects in eligible Group Study areas.

[39] The Solar Massachusetts Renewable Target Program, 225 CMR 20.00.

for inclusion in the Provisional Program. Therefore, the Distribution Companies shall submit an EPS upgrade as part of a CIP only if it meets the following eligibility criteria.

First, we find that the Provisional Program must be limited in scope to specific EPS upgrades and Interconnecting Customers.[40] At the Department's request, the Distribution Companies identified groups of Interconnecting Customers that are likely to be presented with interconnection costs in the next year that are significantly higher than have been historically presented (Exhs. EDC-1 (Eversource); EDC-1 (National Grid); EDC-1 (Unitil)). Upon review, we find the Affected Group Studies identified by National Grid and by Eversource to be appropriate for consideration for participation in the Provisional Program given the advanced nature of these projects and the number of MWs currently seeking to interconnect in the locations under study. Therefore, the Distribution Companies shall submit for a CIP review only those proposals that are identified through a distribution or transmission impact study for one of the above listed Affected Group Studies (Exhs. EDC-1(a) (Eversource); EDC-1(a) (National Grid); EDC-1(a) (Unitil)).

Second, distribution impact studies may result in the identification of EPS upgrades that will allow for the interconnection of one DG facility or multiple DG facilities. Historically, an interconnecting customer that caused the need for a system modification was responsible for the cost of that modification regardless of whether it would enable additional DG to interconnect. As discussed above, the Provisional Program seeks to have all DG

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[40] In this docket, the Department also is investigating a long-term system planning program. Such a program, if established, would contemplate system planning across the entire Commonwealth.

enabled by a specific EPS modification pay a pro rata share of the modification cost. However, we find that in the situation where the interconnection of a DG facility triggers the need for an EPS modification that will enable only that facility's interconnection, the modification would not be appropriate for the Provisional Program. As such, a Distribution Company only may submit a CIP Proposal that will enable the interconnection of multiple DG facilities.

Third, the Department has a responsibility to protect ratepayer interests in the delivery of safe, secure, reliable, and cost-effective electric service. The Provisional Program poses a financial risk to distribution customers if a CIP is approved and DG capacity enabled by that CIP is not utilized by DG facilities seeking to interconnect during the Rate Recovery Period. In that circumstance, distribution customers would have paid for system upgrades without repayment from later Interconnecting Customers. We understand that the cost of interconnection is a key factor for an Interconnecting Customer in determining whether it can move forward with interconnection. The Distribution Companies indicated that, based on historical data, the threshold at or below which Interconnecting Customers have agreed to pay to interconnect is typically less than $100/kW, that some facilities have been able to interconnect for up to $500/kW, and that only a very small handful of facilities have ever paid more than $500/kW to interconnect (Exhs. EDC-3 (Eversource); EDC-3 (National Grid); EDC-3 (Unitil)). Stakeholders have indicated that it will be difficult to keep their DG facilities viable if the cost for interconnection is higher than $200/kW to $300/kW (Exhs. Stakeholder-2 (BlueWave Solar); Stakeholder-2 (Borrego Solar); Stakeholder-2

(Catalyze); Stakeholder-2 (ConEd); Stakeholder-2 (CVE North America); Stakeholder-2 (Entero Energy); Stakeholder-2 (Florence Electric); Stakeholder-2 (Galehead Development); Stakeholder-2 (Hexagon Energy); Stakeholder-2 (Ironwood Renewables); Stakeholder-2 (Longroad Energy); Stakeholder-2 (NECEC, CCSA, SEIA); Stakeholder-2 (NextGrid); Stakeholder-2 (Parallel Products); Stakeholder-2 (Renewable Energy Development Partners); Stakeholder-2 (Seal Rock Energy); Stakeholder-2 (SunConnect); Stakeholder-2 (SunRaise Investments and ReWild Renewables); Stakeholder-2 (Syncarpha Capital); Stakeholder-2 (TJA Clean Energy)). Based on our review of this cost information, we find that it reasonable to limit the maximum cost-per-kW for an eligible CIP in the Provisional Program to $500/kW, which we find to be the maximum cost that likely would result in DG enabled by a CIP to interconnect within the Rate Recovery Period. Therefore, a Distribution Company may submit a CIP for Department review only those Provisional Program proposals that would result in a cost to Interconnecting Customers of $500/kW or less. Furthermore, in recent years, the Legislature has indicated a desire for declining costs to distribution customers associated with DG facilities. See St. 2016, c. 75, § 11(a) (DOER shall adopt rules and regulations that lower the cost of the Commonwealth's solar incentive programs for ratepayers). While we are not setting a maximum cost to distribution customers as an eligibility criterion for CIPs, a significant factor in the Department's review of CIPs is the amount of costs allocated to distribution customers and any costs borne by ratepayers must be clearly justified.

Fourth, in furtherance of our goal to have eligible CIPs enable future DG that likely would interconnect during the Rate Recovery Period and provide benefits to ratepayers, a Distribution Company must identify the specific geographic area served by the EPS upgrades constructed as part of a CIP and must be able to demonstrate that the amount of enabled DG likely will be interconnected in that geographic area within the proposed Rate Recovery Period.

Fifth, as discussed above a significant reason that the Department is establishing the Provisional Program is the immediate risk that hundreds of MWs of DG projects currently under development may not move forward due to the level of EPS upgrade costs that will likely be allocated to those Interconnecting Customers. Furthermore, non-distribution company stakeholders state that the length of construction timelines is critical to the viability of their DG projects, and most indicate that one to three years is the maximum construction timeline for which their facilities could remain viable (e.g., Exhs. Stakeholder-3 (BlueWave Solar); Stakeholder-3 (Borrego Solar); Stakeholder-3 (Catalyze); Stakeholder-3 (CVE North America); Stakeholder-3 (Entero Energy); Stakeholder-3 (Florence Electric); Stakeholder-3 (Galehead Development); Stakeholder-3 (Hexagon Energy); Stakeholder-3 (Ironwood Renewables); Stakeholder-3 (Longroad Energy); Stakeholder-3 (NECEC, CCSA, SEIA); Stakeholder-3 (Nexamp); Stakeholder-3 (NextGrid); Stakeholder-3 (Parallel Products); Stakeholder-3 (Renewable Energy Development Partners); Stakeholder-3 (SEBANE and MassSolar); Stakeholder-3 (SunConnect); Stakeholder-3 (SunRaise Investments and ReWild Renewables); Stakeholder-3 (Syncarpha Capital); Stakeholder-3 (TJA Clean Energy);

Stakeholder-3 (Zero-Point Development)). Therefore, the time required to construct the EPS upgrades associated with a CIP will be a significant consideration. The Department finds it necessary to limit eligibility in the Provisional Program to CIPs for which the construction timeline provides a likelihood that the DG facilities currently in the interconnection queue will be able to remain viable and interconnect following completion of the EPS upgrades associated with a CIP. The Distribution Companies indicate that construction timelines range from two to five years depending on the specific EPS upgrade (Exhs. EDC-1(c) (Eversource); EDC-1(c) (National Grid); EDC-1(c) (Unitil)). The Department also recognizes that many aspects of the construction timeline are outside the full control of the Distribution Companies (e.g., local permitting, siting constraints, etc.). Accordingly, based on our review of the construction timeline information and in recognition of the Distribution Companies' limitations to control certain aspects of the construction timeline, the Department directs the Distribution Companies to submit CIPs only where they can demonstrate that the aspects of the construction timeline within their control can be completed within a maximum of four years from the conclusion of the Department's adjudicatory process.[41] Further, we urge the Distribution Companies to use commercially reasonable efforts to accelerate procurement and construction schedules for completing these upgrades.[42]

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[41] For these purposes, the Department's adjudicatory process includes completion of the adjudicatory proceeding, issuance of a final Order, ruling on any post-Order motions, and ruling on any judicial appeal.

[42] These efforts could include partnering with the associated DG developers in public outreach to inform communities of the purpose of the EPS upgrade, to explain

D. Process for Projects in Group Studies

Currently, upon completion of a Group Study, the Distribution Company presents the study results to the group and each group member has 15 calendar days to determine whether it will proceed in the interconnection process ("Notice Period"). M.D.P.U. No. 375, § 3.4.1(i); M.D.P.U. No. 55A, § 3.4.1(i); M.D.P.U. No. 1468, § 3.4.1(i). Provided that the group membership does not change during the Notice Period, the Distribution Company sends an executable ISA to each group member:

(a) within 15 calendar days of the end of the Notice Period if the group has three or fewer interconnection applications;

(b) within 25 calendar days of the end of the Notice Period if the group has four or five interconnection applications; and

(c) within 35 calendar days of the end of the Notice Period if the group has more than five interconnection applications

M.D.P.U. No. 375, § 3.4.1(i); M.D.P.U. No. 55A, § 3.4.1(i); M.D.P.U. No. 1468, § 3.4.1(i). An Interconnecting Customer has 20 business days to execute an ISA following receipt from a Distribution Company or its interconnection application will be considered withdrawn, and the Interconnecting Customer would need to reapply for interconnection. DG Interconnection Tariff, § 3.6.2.

To provide regulatory certainty and to preserve the interconnection process under the DG Interconnection Tariff, the Department finds that, for purposes of the Provisional Program, the Notice Period for any Group Study for which a Distribution Company submits

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long-term benefits of the upgrade, and potentially to gain an understanding of community needs.

a CIP shall be 15 business days from the issuance of a Department final Order in the underlying CIP adjudicatory proceeding, unless otherwise directed by the Department.

E. Conclusion

For the reasons set forth above, the Department finds that establishment of the Provisional Program with a modified cost allocation and cost recovery methodology is consistent with the public interest. Under the Provisional Program, CIPs must be based on the cost allocation and cost recovery methodology set forth in the Straw Proposal and must comply with the eligibility standards set forth in Section II.C, above. Accordingly, the Distribution Companies are directed to develop CIPs in compliance with the directives contained herein and file any proposed CIP consistent with the timelines set forth in Section II.B, above.

The Department acknowledges that Unitil states that it does not have any applications or groups of applications in process that are expected in the next year to result in interconnection costs that are significantly higher than have been historically presented (Exh. EDC-1 (Unitil) at 1). In addition, Unitil notes that it does not currently have any expectations that there will be a need for significant EPS upgrades as a result of DG facilities seeking to interconnect, but that if it were to receive applications for large DG facilities in the next year it could trigger a need to study whether such upgrades are required (Exh. EDC-1 (Unitil) at 1). The Department accepts Unitil's representations; therefore, at this time, the Department does not anticipate that Unitil will submit any CIPs consistent with the criteria for the Provisional Program as set forth herein.

Nevertheless, to assist the Department in its evaluation of the Provisional Program, Unitil shall continue its evaluation of DG applications and determine any DG projects that likely would withdraw from Unitil's DG interconnection queue due to anticipated high interconnection costs. Unitil shall report the results of its evaluation each year on February 1st for the previous calendar year.

III. ORDER

Accordingly, after due consideration, it is

ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil, NSTAR Electric Company d/b/a Eversource Energy, and Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid shall implement the provisional program for distributed energy resource planning and for the assignment and recovery of associated costs as set forth herein; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil, NSTAR Electric Company d/b/a Eversource Energy, and Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid shall comply with all directives contained in this Order.

By Order of the Department,

Matthew H. Nelson, Chair

Robert E. Hayden, Commissioner

Cecile M. Fraser, Commissioner

ATTACHMENT A

PARTICIPANTS

DISTRIBUTION COMPANIES

Fitchburg Gas and Electric Light Company d/b/a Unitil

Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid

NSTAR Electric Company d/b/a Eversource Energy

STAKEHOLDERS

Attorney General of the Commonwealth of Massachusetts

Massachusetts Department of Energy Resources

Northeast Clean Energy Council ("NECEC")

Coalition for Community Solar Access ("CCSA")

Solar Energy Industries Association ("SEIA")

BlueHub Capital Inc.

BlueWave Solar

Borrego Solar Systems, Inc.

Catalyze

ConEd Clean Energy Businesses

CVE North America

Entero Energy

Florence Electric, LLC

Galehead Development

Hexagon Energy

Interstate Renewable Energy Council, Inc.

Ironwood Renewables, LLC

Longroad Energy

MassSolar

Nexamp, Inc.

NextGrid Inc.

Parallel Products Solar Energy, LLC

Pope Energy

Renewable Energy Development Partners, LLC

ReWild Renewables
Seal Rock Energy
Solar Energy Business Association of New England ("SEBANE")
SunConnect Corporation
SunRaise Investments
Syncarpha Capital, LLC
TJA Clean Energy, LLC
Zero-Point Development, Inc.

ATTACHMENT B

EXHIBITS AND COMMENTS

EXHIBITS

EDC-1 (Eversource)
EDC-2 (Eversource)
EDC-3 (Eversource)
EDC-4 (Eversource)
EDC-5 (Eversource)

EDC-1 (National Grid)
EDC-2 (National Grid)
EDC-3 (National Grid)
EDC-4 (National Grid)
EDC-5 (National Grid)

EDC-1 (Unitil)
EDC-2 (Unitil)
EDC-3 (Unitil)
EDC-4 (Unitil)
EDC-5 (Unitil)

EDC-2-1 (Eversource)
EDC-2-2 (Eversource)
EDC-2-3 (Eversource)
EDC-2-4 (National Grid)
EDC-2-5 (National Grid)
EDC-2-6 (Unitil)

EDC-3-1 (Eversource)
EDC-3-2 (National Grid)
EDC-3-3 (National Grid)
EDC-3-4 (National Grid)
EDC-3-4 (Eversource)
EDC-3-5 (National Grid)
EDC-3-5 (Eversource)
EDC-3-6 (National Grid)
EDC-3-6 (Eversource)
EDC-3-7 (National Grid)
EDC-3-7 (Eversource)

EDC-3-8 (National Grid)
EDC-3-8 (Eversource)
EDC-3-9 (National Grid)
EDC-3-9 (Eversource)
EDC-3-10 (National Grid)
EDC-3-10 (Eversource)

Stakeholder-5 (Attorney General)

Stakeholder-1 (BlueHub Capital)
Stakeholder-2 (BlueHub Capital)
Stakeholder-3 (BlueHub Capital)
Stakeholder-4 (BlueHub Capital)
Stakeholder-5 (BlueHub Capital)

Stakeholder-1 (BlueWave Solar)
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Stakeholder-4 (BlueWave Solar)
Stakeholder-5 (BlueWave Solar)

Stakeholder-1 (Borrego Solar Systems)
Stakeholder-2 (Borrego Solar Systems)
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Stakeholder-5 (Borrego Solar Systems)

Stakeholder-1 (Catalyze)
Stakeholder-2 (Catalyze)
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Stakeholder-4 (Catalyze)
Stakeholder-5 (Catalyze)

Stakeholder-1 (ConEd)
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Stakeholder-1 (CVE North America)
Stakeholder-2 (CVE North America)
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Stakeholder-1 (Entero Energy)
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Stakeholder-1 (Florence Electric)
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Stakeholder-1 (Galehead Development)
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Stakeholder-1 (Hexagon Energy)
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Stakeholder-1 (Ironwood Renewables)
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Stakeholder-1 (Longroad Energy)
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Stakeholder-3 (Longroad Energy)
Stakeholder-4 (Longroad Energy)
Stakeholder-5 (Longroad Energy)

Stakeholder-1 (NECEC, CCSA, SEIA)
Stakeholder-2 (NECEC, CCSA, SEIA)
Stakeholder-3 (NECEC, CCSA, SEIA)

Stakeholder-4 (NECEC, CCSA, SEIA)
Stakeholder-5 (NECEC, CCSA, SEIA)

Stakeholder-1 (Nexamp)
Stakeholder-2 (Nexamp)
Stakeholder-3 (Nexamp)
Stakeholder-4 (Nexamp)
Stakeholder-5 (Nexamp)

Stakeholder-1 (NextGrid)
Stakeholder-2 (NextGrid)
Stakeholder-3 (NextGrid)
Stakeholder-4 (NextGrid)
Stakeholder-5 (NextGrid)

Stakeholder-1 (Parallel Products)
Stakeholder-2 (Parallel Products)
Stakeholder-3 (Parallel Products)
Stakeholder-4 (Parallel Products)
Stakeholder-5 (Parallel Products)

Stakeholder-1 (Pope Energy)
Stakeholder-2 (Pope Energy)
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Stakeholder-1 (Renewable Energy Development Partners)
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Stakeholder-1 (SEBANE and MassSolar)
Stakeholder-2 (SEBANE and MassSolar)
Stakeholder-3 (SEBANE and MassSolar)
Stakeholder-4 (SEBANE and MassSolar)
Stakeholder-5 (SEBANE and MassSolar)

Stakeholder-1 (Seal Rock Energy)
Stakeholder-2 (Seal Rock Energy)
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Stakeholder-4 (Seal Rock Energy)
Stakeholder-5 (Seal Rock Energy)

Stakeholder-1 (SunConnect)
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Stakeholder-5 (SunConnect)

Stakeholder-1 (Sunraise and ReWild Investments)
Stakeholder-2 (Sunraise and ReWild Investments)
Stakeholder-3 (Sunraise and ReWild Investments)
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Stakeholder-5 (Sunraise and ReWild Investments)

Stakeholder-1 (Syncarpha Capital)
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Stakeholder-5 (Syncarpha Capital)

Stakeholder-1 (TJA Clean Energy)
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Stakeholder-5 (TJA Clean Energy)

Stakeholder-1 (Zero-Point Development)
Stakeholder-2 (Zero-Point Development)
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Stakeholder-4 (Zero-Point Development)
Stakeholder-5 (Zero-Point Development)

Stakeholder-2-1 (Attorney General)
Stakeholder-2-2 (Attorney General)

Stakeholder-2-1 (BlueHub Capital)
Stakeholder-2-2 (BlueHub Capital)
Stakeholder-2-3 (BlueHub Capital)

Stakeholder-2-1 (Borrego Solar Systems)
Stakeholder-2-2 (Borrego Solar Systems)

Stakeholder-2-3 (Borrego Solar Systems)

Stakeholder-2-1 (DOER)

Stakeholder-2-1 (Interstate Renewable Energy Council)

Stakeholder-2-1 (Pope Energy)
Stakeholder-2-2 (Pope Energy)
Stakeholder-2-3 (Pope Energy)

Stakeholder-2-1 (NECEC, CCSA)
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Stakeholder-2-3 (NECEC, CCSA)

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Stakeholder-2-3 (Sunraise Investments and ReWild Renewables)

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Stakeholder-2-3 (Syncarpha Capital)

Stakeholder-2-1 (Zero-Point Development)
Stakeholder-2-2 (Zero-Point Development)
Stakeholder-2-3 (Zero-Point Development)

Comments

Reply Comments of Longroad Energy (June 8, 2021)
Joint Reply Comments of National Grid, NECEC, CCSA, SEBANE, SEIA, MassSolar, Zero-Point Development, Borrego Solar, Nexamp, Bluewave Solar, Ameresco, Sunraise Investments LLC, Sol Systems, LLC (June 8, 2021)
Reply Comments of DOER (June 8, 2021)
Reply Comments of Pope Energy (June 8, 2021)

Reply Comments of the Attorney General (June 8, 2021)
Reply Comments of Nexamp (June 8, 2021)
Reply Comments of Borrego Solar (June 8, 2021)
Reply Comments of Zero-Point Development (June 8, 2021)
Joint Reply Comments of Senators Marc R. Pacheco, Michael D. Brady, John J. Cronin, Julian Cyr, James B. Eldridge, Michael O. Moore, Susan L. Moran, Michael J. Rodrigues, and Walter F. Timilty, and Representatives Brian M. Ashe, Peter L. Capano, Antonio F.D. Cabral, Marcos A. Devers, Carmine L. Gentile, Christopher M. Hendricks, Kathleen R. LaNantra, Jack Patrick Lewis, Liz Miranda, Brian W. Murray, Tram T. Nguyen, Jacob R. Olivera, Steven C. Owens, Lindsay N. Sabadosa, Tommy Vitolo, and Steven G. Xiarhos (June 8, 2021)
Reply Comments of SEBANE (June 8, 2021)
Reply Comments of Galehead Development (June 8, 2021)