nationalgrid

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February 28, 2020

By Hand Delivery and E-Filing

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

Re: DG Interconnection – D.P.U. 19-55

Dear Secretary Marini:

On behalf of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), I have enclosed National Grid's Cost Allocation Proposals for filing.

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

Sincerely,

Nancy D. Israel

Nancy D. Israel

Enclosure

cc: Kate Tohme, Hearing Officer
DPU e-filing

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COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Inquiry by the Department of Public Utilities on its own Motion into Distributed Generation Interconnection	))))	D.P.U. 19-55

NATIONAL GRID COST ALLOCATION PROPOSALS

Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or "Company") offers two proposals to the Department of Public Utilities ("Department") in response to the Department's December 26, 2019 Procedural Notice and Request for Public Comments ("Procedural Notice") seeking detailed cost allocation proposals.

In accordance with the Procedural Notice, the Company offers: (1) a proposal for medium and large distributed generation ("DG") Facilities[1] that are currently subject to the Cost Causation Principle;[2] and (2) a proposal for residential and small commercial DG Facilities that have historically not been required to pay for infrastructure modifications (individually "Proposal" and collectively "Proposals"). Both Proposals present an alternative cost allocation principle to the Cost Causation Principle for certain circumstances in which an infrastructure modification is necessary to interconnect one or more DG Facilities.

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1 Capitalized terms that are not defined in these Proposals are defined in Section 1.2 of the Standards for Interconnection of Distributed Generation, M.P.D.U. No. 1320 ("Interconnection Tariff"). Please note that the consensus energy storage system tariff revisions the Company and others jointly submitted on February 26, 2020 propose to revise the definition of "Facility" in Section 1.2 of the Interconnection Tariff. Facilities are also referred to as "projects" herein. When capitalized herein, "System Modifications" means the defined term in the Interconnection Tariff; when used in lower case, the reference is to transmission system modifications or to both distribution and transmission system modifications, as the context requires.

2 As defined in the Procedural Notice, the Cost Causation Principle means the principle currently being used that costs related to infrastructure modifications needed to interconnect a DG Facility are allocated based on the principle that the DG Facility causing the need for a modification must pay for that modification.

The Company offers both Proposals for consideration by the Department, the other electric distribution companies,[3] DG developers, the Department of Energy Resources, the Attorney General's Office, and all other interested stakeholders. The Company has not provided proposed tariff revisions at this time in recognition of the fact that any alternative cost causation principles will need to be workable for all involved parties.

I. BACKGROUND

As the Department encouraged in the Procedural Notice, the EDCs retained a consultant, ScottMadden Inc., to research and analyze DG interconnection cost allocation methods used by electric utilities across the United States to support EDC proposals for alternatives to the Cost Causation Principle. Although National Grid and the other EDCs elected not to submit a joint proposal, the Company expects that its perspective has considerable alignment with those of the other EDCs. National Grid will continue to work with the other EDCs and other stakeholders and expects further alignment will be achievable through additional collaboration. A slide deck summarizing ScottMadden's research and analysis is attached as Appendix A.

A summary table providing a high-level overview of the Company's current cost sharing practice for individual Facilities and Facilities participating in an area study is attached as Appendix B. There are administrative challenges with the Company's current practice, which will continue to increase with DG saturation, as discussed in more detail below.

II. EXECUTIVE SUMMARY OF NATIONAL GRID'S PROPOSALS

The Company proposes several modifications and clarifications of its current practice to enhance cost sharing and allocation among DG Facilities that interconnect to its EPS at a fair share

[3] NSTAR Electric Company d/b/a Eversource Energy ("Eversource") and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), collectively with National Grid, the "electric distribution companies" or "EDCs".

of the costs created by the interconnection requests. These changes are still underpinned by the principle that "cost causers" should pay for the costs they create to interconnect, but also reflect that multiple Facilities should share in upfront costs, that logical distribution System Modifications create capacity that will not be used immediately, and that by using enhanced long term system planning criteria, it is possible an expanded range of costs could be paid for by the Company as planned distribution system improvements and recovered through base distribution rates ("System Improvements") (as contrasted with distribution System Modifications triggered by DG Facilities).[4] The Company will continue to bear the costs of distribution System Improvements, which would not be included in the costs to be allocated under either of the Company's Proposals.

Notably, for medium and large DG Facilities, meaning Facilities that are larger than 25 kW ("Large DG"), the Company proposes to establish Common Upgrade Power Zones ("CUPZ")[5] to share costs among specific Facility owners in defined areas based on the proportion of distribution System Modifications they cause for the capacity they will use. In addition, as described below, if a CUPZ study identifies an opportunity to build incremental capacity at minimal cost, the Company would construct this incremental capacity for future DG Facilities in the area. The construction of this incremental capacity is predicated on approval of recovering these Company investments through a new or existing reconciling mechanism to ensure appropriate cash-flow for the Company for capital committed to enable such System Modifications to move ahead. This would differ from the current requirement for the first project triggering a set of distribution System Modifications to pay all costs up front and the Company perform an after-the-fact cost-

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[4] Such costs may be greater in some cases than they are under current criteria of determining System Improvements.

[5] Please refer to Appendix A, slide 15, for similarities between the Company's CUPZ proposal and practices of utilities in other jurisdictions.

sharing and refund process as other DG Facilities interconnect and pay their share (the status quo), as is discussed in more detail below. The revenue requirement of this incremental capital investment would be recovered through a new or existing reconciling factor applicable to all retail delivery service customers, which would reduce over time as future Large DG Facilities apply for interconnection and pay their equivalent share of System Modifications in the CUPZ area, reducing the remaining investment to be recovered, similar to contributions in aid of construction ("CIAC").

For residential and small commercial DG Facilities, meaning Facilities that are 25 kW[6] or smaller and either apply to interconnect or are interconnected to a radial distribution system (non-network) ("Small DG"), the Company proposes to collect a non-refundable Cost Allocation Fee from all such Facilities. As discussed in more detail below, the Cost Allocation Fee would consist of two primary components: (1) the Localized DG Saturation component; and (2) the Feeder-Level Small DG component. The Localized DG Saturation component would be used to cover the costs of local distribution System Modifications, such as a service transformer or shared secondary upgrade, caused by Small DG applicants. The Feeder-Level Small DG component would be used to cover the costs of any distribution studies that might potentially be triggered by the aggregation of Small DG on a feeder in the absence of a single larger applicant that would otherwise trigger a study. Both of these components together should allow the vast majority of individual Small DG applicants to interconnect without being overburdened by significant unexpected costs and time delays.

[6] The 25kW threshold is identified in this Proposal to essentially act as a proxy for the current eligibility limit for Simplified applicants on a radial distribution feeder. The Company requests that any final rules related to determining "Large DG" vs "Small DG" cost allocation eligibility or requirements align with the eligibility criteria for the Simplified process (i.e., all Simplified applicants would be treated under the "Small DG" process) regardless of how such eligibility criteria may evolve over the course of the parallel topics in D.P.U. 19-55.

III. PROPOSAL 1: PROPOSAL FOR LARGE DG FACILITIES (LARGR THAN 25 kW)

The Company proposes to create CUPZ for Large DG and a process to assign Large DG to the CUPZ for cost allocation and construction. The purpose of the Large DG Proposal is to provide greater cost certainty to DG developers, require developers to pay up front for distribution System Modification costs for which they are responsible and will use (instead of 100% of such costs) and to send price signals to incent DG development in less costly areas. Large DG will continue to be responsible for transmission system modification costs incurred by the Company's transmission provider, New England Power Company ("NEP"), and by other transmission providers, which the Company will pass through to those Facilities causing the modifications for 100% of the cost of those modifications.

A. Primary Goals of the CUPZ Proposal

The following are the Company's primary goals in proposing the CUPZ concept for Large DG:

1. Attempt to lower total costs to interconnect new Large DG. Engineering studies would group Large DG Facilities by date of accepted complete interconnection applications and project geographic locations to minimize distribution study time and costs and total required distribution System Modifications.

2. Possibly reduce upfront financial burdens for interconnecting Large DG through the investment in unused distribution capacity in each CUPZ that costs less than the price cap proposed below.

3. CUPZ would provide price signals that will incent development in areas with less DG congestion and provide a methodology for sharing costs equitably in those areas needing distribution System Modifications.

4. Reduce the Company's administrative burden and the complexity of refunding prorated amounts of System Modifications that end up being shared among Facilities under the Company's current cost allocation and sharing methodology.

5. Once a CUPZ System Modification is committed to by Large DG applicants and the Company, the cost of shared System Modifications (except for potential transmission and site-specific costs) would be known for all other capacity available in the CUPZ, reducing uncertainty about interconnecting additional Large DG.

6. Transmission upgrade costs, net of any costs that are determined to be System Improvements to the transmission owner, would be charged to the Company, and then equitably allocated to only those Facilities that are studied and commit to connect in the study area. These costs would be allocated to the Facilities as determined in each specific transmission or affected system operator ("ASO") study at the Power Supply Area ("PSA") level and above, and on-going transmission related O&M charges would be charged to the Company by NEP or another transmission service provider and subsequently allocated by the Company to all interconnected Large DG Facilities on a MW ratio basis within each PSA.

B. Methodology for Creating CUPZ

The Company would create CUPZs based on distribution engineering studies that would group current Large DG applicants based on the date an interconnection application was deemed complete, status of applications, and geographic location. Each CUPZ would then be divided into sub-areas by substation. These studies would identify required upgrades for the DG capacity studied from the group of Large DG applicants in the CUPZ, but also look to determine if any additional capacity above the studied need could be realized with minimal incremental investment.

In the immediate future following approval of the CUPZ concept, the Company would group current Large DG that did not yet have executed interconnection service agreements ("ISAs") into CUPZ and sub-areas of CUPZ.

Using the same methodology, following approval of the CUPZ concept, the Company would begin to establish additional CUPZs and sub-areas of CUPZs in less saturated areas with potential distribution System Modification costs, if any such areas were identified. These distribution studies would examine constraints in the areas that would need to be addressed to enable additional capacity to be connected but would not result in such distribution System Modifications being constructed preemptively. Large DG Facilities in such areas might still require an ASO transmission study.

C. New Methodology for Allocating System Modification Costs

As discussed below, each CUPZ would have an established cost per enabled kilowatt ("kW"). The Company anticipates that CUPZ price signals would incent development in less costly CUPZ areas (recognizing that state DG incentive programs and other factors also would affect location of DG development). Within a CUPZ and CUPZ sub-area, distribution System Modification costs (if any) would be shared equitably among all capacity enabled in the area.

If the study for a CUPZ or sub-CUPZ determined that additional capacity would be constructed due to the required System Modifications, the Company would invest in the value of the System Modifications exclusive of any System Improvement allocations and would invest Company funds to construct the portion of those System Modifications that would be initially unused and that were less than $400 per kW. This limit on cost per kW is designed to reduce the risk that unused capacity funded by the Company would remain unused in the future, and to serve as an additional negative cost signal to Facilities with significant interconnection costs.

D. Costs to be Considered as "Common Modifications" for Inclusion in a CUPZ

Costs that would be considered common System Modifications for purposes of cost allocation within a CUPZ would include but would not be limited to the following:

a) System modifications triggered by an ASO study:

i. Transmission system upgrades;

ii. Transmission substation upgrades; and

iii. Distribution solutions that serve more than one Facility

b) Distribution system modifications triggered by a Distribution System Impact Study under the Interconnection Tariff ("DSIS"):

i. Distribution substation upgrades; and

ii. Distribution line upgrades that serve more than one project.

c) Project specific distribution System Modifications would not be considered common modifications and the interconnecting customer would be responsible for 100% of those costs, as currently is the case. These project specific distribution System Modifications include:

i. On site distribution work (poles, conductor, metering, reclosers, switches, etc.);

ii. Direct Transfer Trip, if needed between the project site and the substation; and

iii. Distribution line upgrades solely serving the project.

E. Distribution Upgrade Costs in Each CUPZ at Each Substation Would be Assigned Based on the "Enabled Capacity" Allocation Method and Unused Capacity Costs Would be Recovered through a Reconciling Factor

<u>Distribution System Modification Costs</u>

The Company would allocate distribution System Modification costs within the sub-CUPZ at each substation based on total kW enabled by the distribution System Modifications. Costs for the per-kW share allocated to each Large DG project would be committed to by such Facilities through executed ISAs. Unused enabled capacity costs would be initially funded by the Company, and subject to recovery from all retail delivery service customers through a reconciling factor, which would decline with future payments from additional Large DG Facilities that interconnect in the CUPZ sub-zones.

Transmission System Modification Costs

Using the same areas as are used for any CUPZ distribution study, transmission system modification costs would be allocated by utilizing the current ISO-NE study process of a "Zone of Contribution" principle, charging only those Large DG Facilities that were contributing to the need for a transmission system modification. This would be accomplished by taking the following steps:

i. Identify the adverse impact from the ASO study;

ii. Identify the resulting contributing zone around the required transmission system modifications; and

iii. Match this Zone of Contribution to the transmission system modifications (the contribution zone increases in size from smallest to largest in the list below):

- Substation (smallest)
- Power Supply Area
- Circuit (largest).

With the above methodology, ASOs would be able to clearly identify groups of Large DG Facilities in that ASO study that would be contributing to the transmission system modifications.

Transmission and Distribution O&M Costs

The Company would do an annual assessment of both transmission and distribution system operating and maintenance ("O&M") costs, which it would bill to Large DG Facilities interconnecting in each CUPZ; the O&M could differ within each sub-CUPZ based on substation.

Distribution O&M associated with unused capacity would be recovered through the reconciling mechanism; transmission O&M would be a 100% pass-through to the Large DG Facilities interconnected as a result of the ASO study that initially triggered the transmission system modifications.

Large DG Facilities that either individually or in the aggregate are 1 MW or below will only pay for system modification costs triggered by a DSIS and will not be responsible for paying for those transmission system modifications costs triggered in an ASO Study within a CUPZ or sub-CUPZ. However, in the case where there is no CUPZ or sub-CUPZ study and aggregate amounts of Facilities 1 MW or below require the Company to require additional capacity from its transmission provider, allocation of transmission upgrade costs would need to be determined.[7]

The Company would invest in the remaining distribution System Modification costs in each CUPZ for the capacity that would not be used immediately. The revenue requirement for this incremental investment, including depreciation expense, return on rate base, property taxes, and O&M for unused capacity, would be recovered from all of the Company's retail delivery service customers.

Large DG Facilities would lock into the CUPZ once their ISA had been fully executed, and the Company had received their initial deposit required by the ISA. All CUPZ-related payments would be non-refundable.

[7] Large DG Facilities that in the aggregate or individually are above 1MW are required to receive an ISO-NE Proposed Plan Application ("PPA") or file a Notification Form. Those Facilities will be actively studied as part of an ASO study and therefore, any Large DG individually or in the aggregate that is 1MW or below will not be responsible for transmission system modifications triggered by an ASO study. Section 2 of PP5-1 lists thresholds for notifications and/or PPA.

F. Distribution Costs to Connect at Each Substation of a CUPZ for Common System Modifications Would then be Known and Fixed Going Forward Once Constructed, Enabling Other Facilities to Interconnect at the Same Cost per kW

As additional Large DG Facilities beyond the ones initially studied in the initial CUPZ study enrolled to connect in the CUPZ, their payments would be a credit against Company-invested capital and thus would reduce the annual revenue requirement in that CUPZ and lower the overall reconciling factor.

Large DG Facilities could join a CUPZ at any time, for 20 years from establishment of the CUPZ, if there is still available capacity.

Costs that are project-specific as identified above, for initial or subsequent Large DG Facilities, rather than common distribution System Modifications, would be collected directly from that Large DG project, as is currently the case. The common distribution System Modifications for any distribution system capacity that is not used would be recovered through a reconciling factor for 20 years. After 20 years, any remaining revenue requirement and O&M associated with that unused capacity would be recovered through base distribution rates as a result of a subsequent base distribution rate case filing.

The Company has provided examples of how the Large DG Proposal would be applied in Appendix C.

IV. PROPOSAL 2: PROPOSAL FOR RESIDENTIAL AND SMALL COMMERCIAL DG FACILITIES (25 kW AND SMALLER) CONNECTING TO A RADIAL DISTRIBUTION FEEDER

For residential and small commercial DG Facilities that interconnect to a radial distribution feeder and are eligible to participate in the Simplified process track ("Small DG"),[8] the Company proposes to collect a non-refundable fee ("Small DG Cost Allocation Fee"). This fee will address

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[8] See footnote 6 referring to the use of 25 kW or smaller as a proxy.

the increasingly common situation where a Simplified application project triggers significant System Modification costs (relative to project cost) on a random basis. In 2019, such modification requirements affected 7% of Small DG project applications and this rate is expected to increase in the future. Small DG Facilities that are required to pay for these types of System Modifications are roughly twice as likely to cancel than those that require no System Modifications, and this is a major cause of the overall application attrition rate for Simplified Facilities in the Company's experience. This fee would consist of two primary components: (1) the Localized DG Saturation component; and (2) the Feeder-Level Small DG component. The Localized DG Saturation[9] component would be used to cover the costs of the system modifications described below caused by Small DG applicants. The Feeder-Level[10] Small DG component would be used to cover the costs of the distribution studies per year that might potentially be triggered by the aggregation of Small DG on a feeder in the absence of a single larger DG applicant that otherwise would trigger a study. Both of these components together should allow the vast majority of individual Small DG applicants to avoid being overburdened with significant unexpected costs and time delays.

A. Develop Small DG Cost Allocation Fee ($/Kw) Based on Forecasted Small DG

The Company proposes to develop the Small DG Cost Allocation Fee by analyzing historical trends and known policy changes related to Small DG applications to determine a dollar per kW fee that would be paid by all Small DG submitting applications to interconnect to non-

[9] Localized DG Saturation refers to issues caused by the aggregate Small DG capacity (e.g., voltage or reliability issues) that would not impact any customers on the primary side of the local service transformer (on radial feeders).

[10] Feeder-Level issues refer to any operational concerns caused by the aggregate Small DG capacity that would likely impact customers on the primary side of the local service transformer (but would not be attributable to any single Small DG applicant alone).

network systems (radial distribution feeders). The fee would be calculated based on the following proposed formula:

$$\text{Small DG Cost Allocation Fee} = \{[(P_{Apps} \times A_{service}) + (P_{Feeders} \times A_{study})] / P_{size}\} + Z$$

Where:

- Localized DG Saturation component:
  - P_{Apps} = # of Projected Apps Quoted Upgrade / Year
  - $A_{service}$ = Average Actual Upgrade Costs (e.g. $4,000)
- Feeder-Level Small DG component:
  - $P_{Feeders}$ = # of Projected Feeders Saturated by Small DG Only
  - A_{study} = Average Actual Feeder Saturation Study Costs (e.g. $8,000)
- P_{size} = Total kWAC of Projected Apps Submitted / Year
- Z = O&M Revenue Adjustment

The Company recommends that the Small DG cost allocation method described in this Proposal be effective for all applications submitted on or after January 1, 2021 (or another date that is at least three months after approval of the Proposal). This also will allow the Company to update its internal policies to accommodate the changes to its accounting, design, and construction processes as appropriate, and it will ensure that the collection of Cost Allocation Fee components does not occur before there is clarity about the interrelated implications of the other topics in D.P.U. 19-55 (e.g., any adjustments to the eligibility requirements for the Simplified process).

B. Common System Modifications Included in the Localized DG Saturation Component of the Small DG Cost Allocation Fee

The following are the System Modifications that would be considered common modifications and covered by the Localized DG Saturation component[11] of the Cost Allocation Fee: (a) overhead service transformer upgrades, (b) crib splitting or service reconfiguration, (c) service upgrades or new services that are required to enable the interconnection of the proposed DG Facility. If the cost of any such System Modification exceeds $5,000 for any applicant, such applicant will be responsible for paying 100% of the cost minus the $5,000 fee.

Any distribution System Modifications to an Area or Spot Network (i.e., applicants subject to Figure 2 in the Interconnection Tariff) that would be required because of the proposed interconnection of an application under 25 kW would be excluded from the Cost Allocation Fee and these Facilities connecting to a distribution system would be responsible for any distribution System Modification costs as detailed in an executable ISA

In scenarios where the interconnection of a Small DG applicant requires (a) line extensions beyond the number of poles allowed identified in the Company's line extension policies for traditional load customers, (b) single-to-three phase conversions that would result in a change in the nature of the customer's existing service, or (c) any other scenarios where the cost of service equipment upgrades to serve the customer's property exceeds $5,000, then the Company recommends that the Small DG applicant should pay such costs in accordance with the Cost Causation Principle (in addition to any Cost Allocation Fees that the applicant would otherwise have been subject to). This should avoid gaming of the Interconnection Tariff to provide customers

[11] The Company would expect to record these costs as a reduction in capital, similar to a CIAC.

with services that would otherwise have been treated under the normal load customer connection processes.

C. Common System Modifications Included in the Feeder-Level Small DG Component of the Small DG Cost Allocation Fee (for Studying Aggregated Small DG)

The purpose of the Feeder-Level Small DG component is to cover the expense of the engineering analysis in scenarios in which the aggregate, incremental Small DG saturation levels cause a potential concern (i.e., where a single DG applicant of comparable size on the distribution feeder or line segment would have otherwise necessitated a Supplemental Review or DSIS). To avoid overburdening Small DG applicants with these costs, these fees would provide recovery for anticipated engineering analysis when the Company deems there to be a significant risk to safety and reliability due solely to the accumulation of Small DG since the last Supplemental Review or DSIS on the feeder (e.g., the accumulation of 250 kW or more of aggregate nameplate capacity from Small DG since the previous study). Furthermore, these studies could proceed proactively at the pace that the Company deems appropriate for the level of risk.

V. CHALLENGES

A. Unused Transmission Capacity

The definition and subsequent use of "unused capacity" on the transmission system is a difficult principle to implement in New England, a densely networked area. Under the ISO-NE OATT, when a transmission system modification is completed, any capacity on that circuit is open to the market to use. The Company would not be able to reserve the right to any marginal increase in capacity associated with that transmission system modification. The Company will discuss with the ASOs and ISO-NE whether and how it might be possible to allocate transmission costs for which the Company is charged in a similar manner to which the Company proposes to allocate Large DG distribution costs, including with respect to unused transmission capacity. As these discussions and subsequent changes would occur with ISO-NE and the other ASOs, and likely extend through the current calendar year, any such changes are unlikely to impact Facilities currently in any significant ASO studies in the Company's service territory.

B. Cost Estimates

The Interconnection Tariff currently restricts cost increases above the cost estimates in the ISA to 10% (25% for an early ISA), while the reduction in cost after reconciliation is unlimited. With the increase in the scope of System Modifications and in the length of time needed to construct distribution and transmission system modifications due to the influx of DG Facilities, expecting the Company to accurately estimate costs that may not be expended for many months or years is unrealistic. The Company proposes to revise the Interconnection Tariff to allow an EDC to collect up to 125% of the estimated costs in the ISA (as currently is permitted for early ISAs) to reimburse actual costs, after final construction is complete and the actual project costs have been reconciled from the initial estimates.

C. Long Term Bill Impact if Unused Capacity is Never Taken Up by Other Large DG Facilities

The capacity funded by and recovered through a reconciling factor may never be utilized by Large DG Facilities, or not in the near to medium term. If this results in $100 million in unused incremental investment, for example, the initial revenue requirement flowing through the reconciling factor would add an additional $12 million to $14 million per year to customer bills, which otherwise would have been paid for through CIACs. However, the Company anticipates that the pace of DG development in the Commonwealth is likely to continue into at least the medium term (5 to 10 years) and areas with fixed, reasonable common System Modification costs are likely to be highly attractive and utilized, which will lower this potential customer bill impact

VI. CONCLUSION

The Company appreciates the opportunity to submit proposals in response to the Department's Hearing Officer Memorandum seeking detailed cost allocation proposals and looks forward to continued engagement on the issues the Department raised.

Respectfully Submitted,

MASSACHUSETTS ELECTRIC COMPANY
and NANTUCKET ELECTRIC COMPANY
d/b/a NATIONAL GRID

By its attorney,

Nancy D Israel

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Date: February 28, 2020

APPENDIX A

scottmadden
MANAGEMENT CONSULTANTS

Smart. Focused. Done Right.®

Interconnection Cost Allocation

February 28, 2020

Introduction

ScottMadden was retained by Eversource, National Grid and Unitil Corporation (together, the "Massachusetts Electric Distribution Companies" or "EDCs") to prepare research and analysis on interconnection cost allocation methods used by electric utilities across the United States.

- The research and analysis was used to support EDC position papers filed before the Massachusetts Department of Public Utilities ("DPU") in D.P.U 19-55. The DPU requested proposals for alternative interconnection cost allocation methods for Distributed Generation ("DG") facilities.

ScottMadden's approach to the assignment included three phases: research and analysis, evaluation, and financial analysis.

- The research and analysis phase reviewed various methods to allocate and recover capital investments and operations and maintenance (O&M) expenses needed to connect DG facilities to the electric grid. The research focused primarily on those states with high solar penetration.
- The evaluation phase assessed cost allocation methods relative to four design objectives: cost recovery, cost responsibility, DG development and administrative ease.
- The financial analysis phase examined the impact of various cost allocation methods on DG project economics.

Interconnection costs are defined as investments and O&M expenses required to connect DG facilities to the electric grid. There are two types of interconnection costs: Network Expansion Costs and Grid Impact Mitigation Costs.

- **Network Expansion Costs** are related to the electric lines that interconnect the DG project with the grid as well as any additional equipment such as transformers to enable the export of electricity into the grid. Most DG projects generally incur these costs which could be driven by the distance from interconnection point or project-specific requirements, such as project size.
- **Grid Impact Mitigation Costs** are incurred by the utility to mitigate any impacts on the electric grid that a DG project would trigger. These costs are generally related to infrastructure modifications and upgrades.

Introduction (cont.)

Interconnection cost allocation methods vary depending on the magnitude of the upgrade costs and system requirements.

- For residential-sized projects, distribution system upgrades (e.g., transformer upgrade) are in some cases absorbed by the utility and included in rate base.
- For commercial-sized and larger projects, however, distribution system upgrades required to interconnect DG projects safely are commonly paid for by the "cost causer" – or the marginal project in the queue that triggers the distribution upgrades.
  - With more interconnection requests, more distribution upgrades are needed to accommodate greater grid-hosting capacity.

Interconnection costs in Massachusetts are presently allocated based on the principle that the DG facility causing the need for a modification must pay for that modification ("Cost Causation Principle"). The Cost Causation Principle is a method traditionally applied across the United States.

- The primary benefit of the Cost Causation Principle is it creates an incentive for developers to utilize the existing infrastructure.
- The primary drawbacks of the Cost Causation Principles are fairness and efficiency.
  - Fairness refers to situations where future projects may benefit from distribution system upgrades but do not incur the costs, putting cost responsibility of the upgrades on the developer that triggers the need for the upgrades (the "cost-causer").
  - Efficiency refers to procedural delays due to prohibitive upgrade costs that may grind the interconnection queue to a halt for that circuit until a solution is found or the applicant drops out.
  - In addition, the approach creates cost uncertainty for developers.
- Massachusetts has 'Separation of Costs' clause that ensures an interconnecting customer pays only that portion of the interconnection costs resulting from the system modifications required to allow for safe and reliable parallel operation of the DG facility.
  - The clause states: "Should the Company combine the installation of System Modifications with additions to the Company's [Electric Power System] EPS to serve other Customers or Interconnecting Customers, the Company shall not include the costs of such separate or incremental facilities in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff."

scottmadden MANAGEMENT CONSULTANTS

Approach

ScottMadden's approach to the assignment included three phases: 1) research and analysis, 2) evaluation, and 3) financial analysis.

1. **The research and analysis phase included a review of cost allocation methods to allocate and recover capital investments and O&M expenses needed to connect DG facilities to the electric grid.**
   - The research focused primarily on those states with high solar penetration. The research relied on several industry studies and articles, as provided on the next page.

2. **The evaluation phase included an assessment of cost allocation methods based on four design objectives**
   - Cost recovery – interconnection costs are recovered in a timely fashion.
   - Cost responsibility – interconnection costs are recovered in a fair and equitable manner, consistent with how costs are incurred.
   - Distributed Generation development – interconnection costs address public policy principles, including the importance of DG development.
   - Administrative efficiency and simplicity – interconnections costs can be recovered with administrative ease.

3. **The financial analysis phase examined the impact of various cost allocation methods on DG project economics.**
   - The financial analysis utilized DG Project assumptions from various industry sources. In addition, the financial analysis prepared scenarios evaluating the impact of different allocation methods and interconnection costs on DG project economics.

ScottMadden prepared findings related to each phase of the assignment.

Research Materials

Industry Reports

- National Renewable Energy Laboratory (NREL), several reports on interconnection emerging issues and trends
- National Association of Regulatory Utility Commissioners (NARUC) Distributed Energy Resources (DER) Rate Design and Compensation
- Lawrence Berkeley National Laboratory (LBNL), Transmission Benefit Quantification, Cost Allocation And Cost Recovery
- Anderson Economic Group, LLC, Michigan Unplugged? The Case for Shared Investment in Regional Transmission Projects
- Sandia National Laboratories (SNL), Analysis of 100 Small Generation Interconnection Procedure (SGIP) Studies

Industry Articles

- Greentech Media (GTM)
- Public Utilities Fortnightly (PUF)
- NREL

Financial Analysis Assumptions

- Rhode Island Renewable Energy Growth Program: 2020 Celling Price Recommendations (September 2019)
- Department of Energy Resources (DOER) Solar Massachusetts Renewable Target (SMART) Program - 225 CMR 20.00

Federal Energy Regulatory Commission (FERC) Orders and ISO Approaches

- FERC Order 1000 and Order 890
- Independent System Operators (ISO) Cost Allocation Policies
  - MISO Multi-Value Projects
  - ERCOT Competitive Renewable Energy Zones (CREZ)
  - ISO New-England Policies
  - CAISO Wholesale Distribution Access Tariff

Selected Proceedings on Interconnection Procedures and Cost Issues

- Reviewed States include:
  - California
  - New York
  - Hawaii
  - Arizona
  - Minnesota
  - New Jersey
  - Colorado
  - North Carolina
  - Vermont
  - Nevada

Research Findings

The research phase identified seven general approaches to cost allocation and cost recovery.

1. **Cost-Causer Pays**. This approach (or the ‘Cost Causation Principle’) assigns full cost responsibility to the first DG project that causes the need for system upgrade. This is the method most commonly implemented in the United States.
   - This method creates an incentive for developers to utilize the existing infrastructure.
   - However, the approach raises fairness or free rider concerns where future projects benefit from distribution system upgrades but do not incur the costs. In addition, the approach may create procedural delays and clog the interconnection queue due to prohibitive upgrade costs.

2. **Cost-Causer Group Pays**. This approach assigns cost responsibility to a group of DG projects that cause the need for the upgrades. This approach is designed to address fairness or free rider concerns. There are three variations of this approach:
   - **2a. Developer Group Pre-Upgrade Payment**. The DG projects pay upfront 100 percent of the costs. The DG projects share system upgrade costs among a group of DG applications evaluated at the same time. Applications submitted within a time window are evaluated as a group and system upgrade costs are shared across all projects based on their relative contribution toward the upgrade.
     - The approach is more efficient, and reduces the likelihood that applications stall when system upgrades are required.
     - However, applicants must remain through the entire group-study process. This can cause delays as projects change or applicants drop out. Studies may need to be repeated and costs re-allocated, which could create cost inefficiencies and delays. In addition, the process can be lengthy with no timeline requirements, and may be inefficient for small DG projects.
   - **2b. Developer Group Post-Upgrade Reimbursement**. The first DG project pays 100 percent of costs and is later reimbursed when other DG projects are added. Future projects pay a prorated share of the costs based on their capacity. Payments are made to the utility who then distributes it to developer(s). Cost sharing ends when the new capacity is maxed out.
     - The approach is equitable, spreads costs among those who benefit, includes a relatively streamlined process, and improves cost certainty for utility. The approach can be efficient for quickly getting large numbers of small projects online.
     - However, the DG Project which triggers the system upgrade may not have access to upfront capital. The approach may result in DG projects forced to absorb full cost of upgrade if no subsequent projects arise. And finally, small DG projects may need to wait for a large project to pay the upfront capital.

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Research Findings (cont.)

2. **Cost-Causer Group Pays (cont.)**
   - **2c. Utility Post-Upgrade Reimbursement**. An approach where the utility pays 100 percent of costs when the system upgrade is triggered from interconnection applications and is later reimbursed as projects join. Costs are prorated to interconnecting projects on a $/kW basis depending on future available capacity. Subsequent projects (that benefit from the upgrades) also pay a prorated portion of the upgrade costs (based on the relative capacity-to-total new capacity).
     - The approach is equitable, spreads costs among those who benefit, and includes a relatively quick and streamlined process The approach can be efficient for quickly getting large numbers of small projects online. Finally, the approach enables small projects to interconnect even in the absence of large projects.
     - However, the approach raises cost recovery concerns for the utility if not enough future projects are in the queue. Costs may be recovered in the rate base, which creates bill impact and cross-subsidization concerns.

3. **Pre-emptive Upgrades**. An approach where the utility pre-emptively upgrades select portions of distribution system and later recovers costs from developers or ratepayers. The utility pays for initial investment at pre-selected targeted area(s) with the expectation of recovering the costs through future applications. DG projects connecting to the upgraded network reimburse the utility through a pro-rated fee based on the cost of the upgrade, network capacity, and project capacity. The prorated fee is evenly divided among projects by KW size.
   - The approach is equitable, spreads costs among those who benefit, and improves cost certainty for developers (decreasing financial risk and potentially increasing the developer's ability to obtain financing). Pre-emptive upgrades approach may also reduce project timelines, allow small projects to still be viable due to reduced allocation amount, and places initial cost burden on utility as opposed to small developers.
   - However, the cost recovery risk is transferred to the utility and ratepayers. Costs may go into a regulatory asset and if the reimbursements do not cover the costs, then the net balance is recovered from ratepayers. The approach does not account for distribution circuit upgrades that certain projects will still have to absorb with no reimbursement policy in place.

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Research Findings (cont.)

4. **Flexible Interconnect Capacity Solution**. An approach where instead of implementing upgrades, the utility and developer agree to power curtailment in case of any system issues instead of a system upgrade. The method includes minimal capital costs for developers, but substantial software costs for utility to manage the power curtailment capability. Developer project feasibility may be impacted with power curtailments reducing revenues. The concept has previously been implemented in UK.
   – The approach results in avoided upgrade costs for developers, utilities, and ratepayers. Loss in revenue, administrative challenges, and potential hardware requirements may impact DG project's financial feasibility.
   – The approach avoids implementation of any system upgrades. This becomes challenging on circuits where significant additional amounts of DG projects are anticipated to interconnect in the future.
   – The method also requires capabilities at the utility to actively manage or signal DG to curtail power through an Advanced Distribution Management System (ADMS) or other means. At present, this would not be feasible until such systems are deployed by Massachusetts EDCs in the future through the Commonwealth's Grid Mod proceeding.
5. **Fixed Interconnection Fees.** An approach where the upgrade costs are recovered from all interconnecting customers through a one-time fee. Approach is most commonly applied for residential and small commercial customers. The approach includes interconnection costs of upgrades as part of rate base and recovers from all interconnecting customers through a one-time fee.
   – Per NREL, although this approach can facilitate interconnection, its fairness and effectiveness is still under evaluation, and there is little experience with such solutions to date.
   – One key concern is the over- or under- recovery of costs which can result in cross-subsidization between interconnecting customer and other ratepayers.
6. **Utility Financing of Interconnection Costs**: An approach where interconnection costs can be financed by the utility and recovered from the DG developer through monthly charges developed based on 'traditional revenue requirement' method. The revenue requirements are calculated for the costs of facilities or system upgrades. With this method, the interconnection costs are financed for the developer at utility's cost of capital.
   – While the method eases the burden of any upfront payments from the developer, the utility's recovery of costs is over a longer timeframe. This is mitigated by the return that the utility is able to earn on the investment through the recovery timeframe.
7. **Recovery of O&M Expenses:** An approach where the utility's O&M costs related to the interconnection facilities are recovered from the DG developer through a monthly charge.

Research Findings (cont.)

Lessons learned from transmission: there are many examples of the pre-emptive upgrades approach for transmission investments to achieve public policy goals, particularly in MISO and ERCOT.

1. **FERC Order 1000**
   - As an initial matter, FERC provided general guidance on development of transmission cost allocation methods, particularly in Order 890 and Order 1000.
   - FERC Order 1000 addressed questions on cost allocation for transmission upgrades and grid expansion, and gave regions flexibility to develop unique cost allocation methods that would balance the interests of transmission providers, customers, and the broader network.
2. **MISO Cost Allocation for MVPs**
   - MISO developed a cost allocation method for a special class of projects labeled “Multi-Value Projects” (MVPs).
   - MVPs are regionally beneficial transmission projects designed to support energy policy imperatives while also providing reliability and economic benefits over multiple MISO zones.
   - Costs are allocated on a system-wide basis using a “postage-stamp-to-load” cost allocation.
3. **ERCOT Cost Allocation for CREZs**
   - ERCOT developed a unique cost allocation method for transmission projects in designated Competitive Renewable Energy Zones (CREZ).
   - Transmission companies bear the initial up-front costs for the investments but funding comes from consumers who pay through a cost socialization method applied across the entire ERCOT footprint.
   - Costs socialization reflects that the transmission benefits are shared by everyone in the region.

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Evaluation Findings

Methodology	Description	Design Objectives: Cost Responsibility	Cost Recovery Risk	DG Development	Administrative Ease
1. Developer – Cost Causer Pays (Traditional Approach)	First DG Developer pays 100% of costs	Potential 'Free-Riders'	Recover costs from developer, except overruns	Higher costs, potential delays and terminations	In place today
2a. Developer Group – Pre-Upgrade Payment (Traditional Approach)	Group of DG Developers pay before upgrade (costs allocated)	Better aligns costs and benefits	Recover costs from developer(s), except overruns	Lower costs for first project	In place today
2b. Developer Group – Post-Upgrade Reimbursement	First Developer pays 100%, and is reimbursed by other developers (costs allocated)	Better aligns costs and benefits if other developers participate	Recover costs from developer(s), except overruns	Uncertainty of reimbursements	Additional processes for allocation and re-imbursement
2c. Utility – Post-Upgrade Reimbursement	Utility pays 100%, and is reimbursed by other developers (costs allocated)	Better aligns costs and benefits if other developers participate	Recover costs primarily from developer(s)	Shared costs, may improve certainty	Additional processes for allocation and re-imbursement
3. Developer(s)/ Ratepayers – Pre-emptive Upgrades	Utility invests preemptively, later recovers from developers. Upgrade costs not recovered are rate-based	Better aligns costs and benefits if other developers participate	Potential uncertainty in cost recovery	Lowers cost for first project, improves cost certainty	Additional processes for allocation and re-imbursement

More Favorable Impacts — **Less Favorable Impacts**

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Evaluation Findings (cont.)

Methodology	Description	Design Objectives: Cost Responsibility	Cost Recovery Risk	DG Development	Administrative Ease
4. Developer(s) – Flexible Interconnect Capacity Solution	Developer(s) pay indirectly through power curtailment (that avoids the need for upgrade)	No upgrade costs	No upgrade costs	May erode project economics	Additional processes and investments to manage curtailments
5. Fixed Interconnection Fees (Applicable mostly to Residential Customers)	Utility maintains and upgrades the distribution system and recovers the costs through a one-time fee from interconnecting customers	Better aligns costs and benefits if other developers participate	Potential uncertainty in cost recovery	Lowers cost for first project, improves cost certainty	In place today
6. Utility Financing of Interconnection Costs	Utility recovers interconnection costs through monthly charges based on traditional revenue requirement method	Better aligns costs and benefits if other developers participate	Cost recovery over a longer timeframe with potential credit risk exposure	Impact on project economics neutral to negative	Additional processes for long-term administration
7. Recovery of O&M Expenses	Utility maintains and upgrades the distribution system and recovers the O&M costs through monthly charges	Better aligns costs and benefits	Better aligns costs and revenues	Adds cost responsibility for developer	Additional processes for administration

More Favorable Impacts ← → **Less Favorable Impacts**

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Financial Analysis Findings

ScottMadden developed a cash flow model for the financial analysis.

- The purpose of the financial analysis was to examine the impact of various interconnection cost allocation methods on the cost of DG.
- The model “solves for” IRR based on compensation structure and varying interconnection costs.
- The Base Case was developed using Rhode Island Renewable Energy Growth Program: 2020 Celling Price Recommendations (Sept. 2019) (pg. 21-22) and DOER Massachusetts SMART Compensation Program.

  - Facility Assumptions
    - Facility Size: 2.0 MW
    - Capital Costs: $1.447 per Watt$_{DC}$ ($3.4M)
      - Excludes average Interconnection Costs: $0.155 per Watt$_{DC}$
    - Capacity Factor: 15.30%
    - Annual Degradation Factor: 0.50%
    - Facility Life: 30 Years (Lazard / NREL)
  - SMART Compensation Assumptions
    - Electric Distribution Company: Varies
    - Capacity Block: Last Available Block
      - Block 8 for Eversource West, Eversource East, and Massachusetts Electric
      - Block 4 for Fitchburg Gas & Electric
    - Facility Size: 2.0 MW
    - Base Compensation: Varies by EDC and Block
    - Rate Adder Type: None
  - O&M Costs
    - Fixed O&M Costs: $14.50 per kW
    - Site Lease: $50,000 per year
    - Project Management: $12,000 per year
    - Insurance: 0.45% of total cost
  - Capital Structure and ITC
    - Equity 40% (at 9.50% Cost of Equity)
    - Investment Tax Credit: 26.0%
      - Reduced accelerated tax benefit by one-half of ITC i.e., 87%
    - Debt 60% at 6.00% cost of debt with 15-year term, 2.0% lender’s fee
    - Inflation: 2.00%

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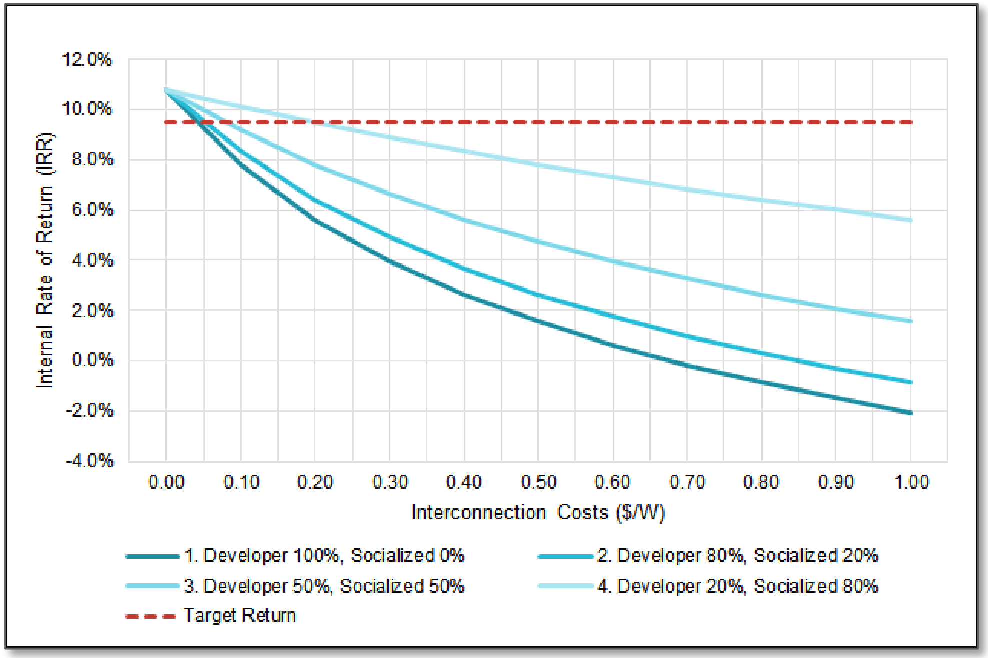
Financial Analysis Findings (cont.)

The illustrative analysis shows that DG project economics fall rapidly as interconnection costs increase.

- The illustrative analysis shows that the IRR on a DG project improves with various forms of cost socialization.

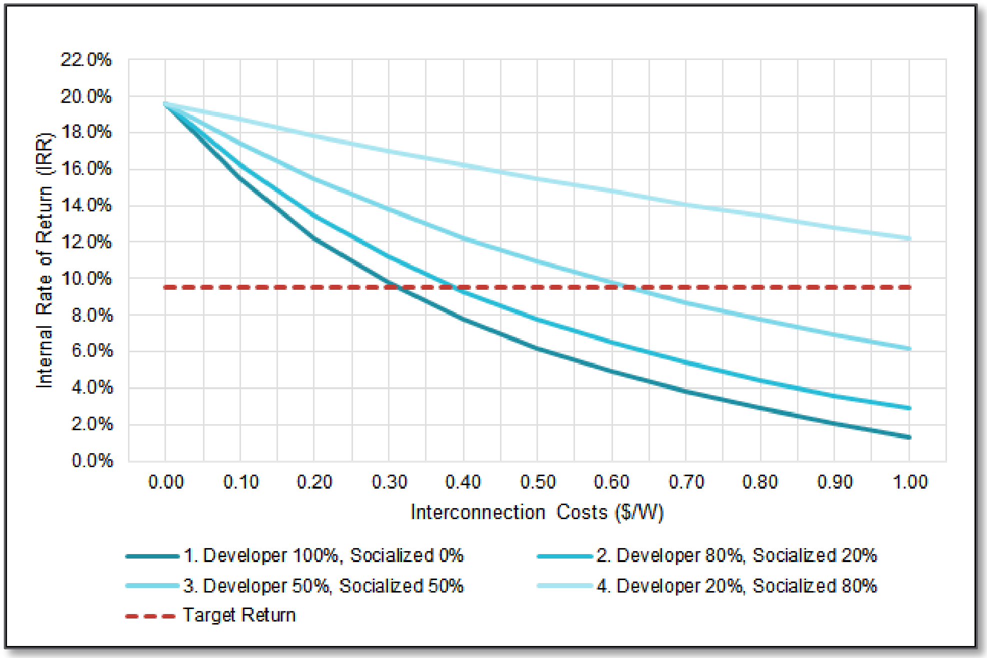
Eversource West Service Area

DG Developer IRR Comparison (Illustrative)



Eversource East Service Area

DG Developer IRR Comparison (Illustrative)



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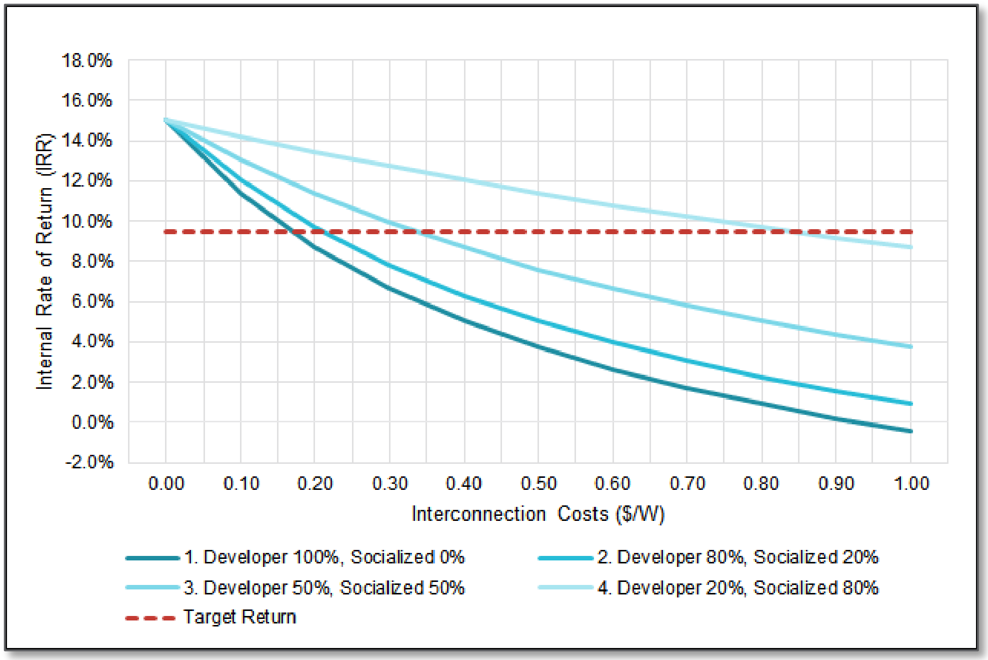
Financial Analysis Findings (cont.)

The illustrative analysis shows that DG project economics fall rapidly as interconnection costs increase.

- The illustrative analysis shows that the IRR on a DG project improves with various forms of cost socialization.

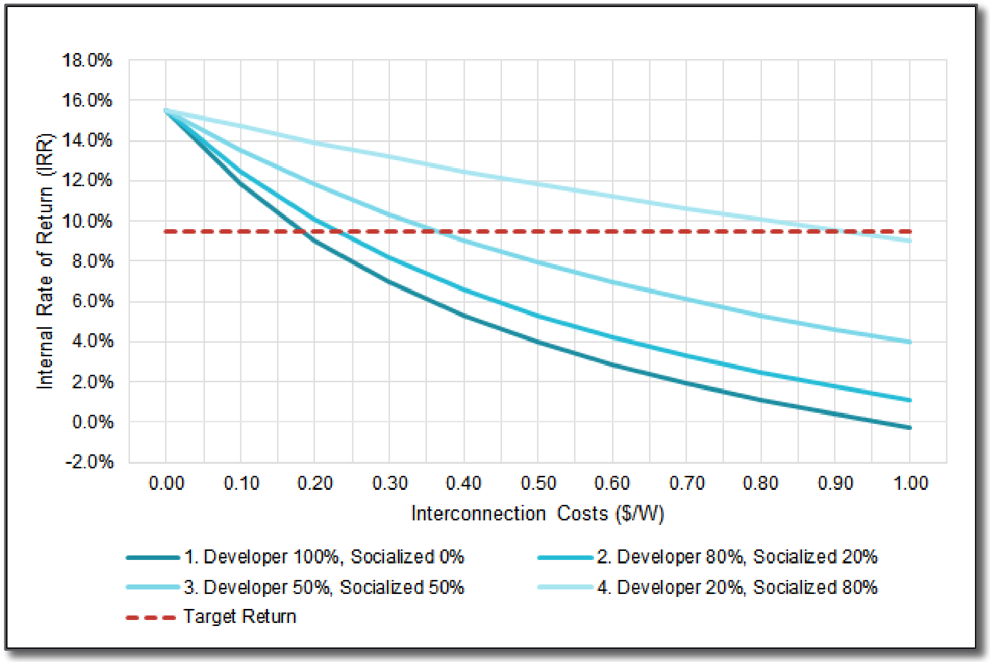
Massachusetts Electric Service Area

DG Developer IRR Comparison (Illustrative)



Fitchburg Gas & Electric Service Area

DG Developer IRR Comparison (Illustrative)



CUPZ Cost Allocation

There is consideration of a new cost allocation approach to facilitate DG projects called “Common Upgrade Power Zones”. The approach would be aligned with the “cost-causer pays” principle but combines the additional concept of the utility post-upgrade reimbursement discussed as approach 2c.

- The approach establishes Common Upgrade Power Zones (CUPZ) for projects over 25 kW (non-simplified). Distribution upgrade costs net of system improvement costs would be allocated at substation level to all “Enabled Capacity.” Potential benefits to developers include:
  - Lower costs to integrate new DG.
  - Cost sharing among developers.
  - Improved cash-flows.
  - Clear costs for additional DG to connect in the same area.
- The approach would be enabled by the EDCs investing in the unused distribution capacity. A cost recovery factor would then recover the revenue requirement associated with that investment.
  - Upfront capital cost for developers would be reduced when upgrades create capacity they do not utilize.
  - Developers would also be responsible for O&M payments related to ongoing expenses associated with the upgraded assets
  - Future projects’ Contributions in Aid of Construction (CIAC) would reduce the invested capital being recovered in the factor
- The approach provides for a reduction to the recovery factor as more developers enroll in each CUPZ.

CUPZ Cost Allocation (cont.)

CUPZ Cost Allocation: Key Components	Similarities to Other Utilities' Practices
■ **DG Development Zones:** Creation of Zones for system upgrades and DG development. Price signals incentivize development in less congested areas, and share costs equitably in those areas with costs	Similar to ERCOT's CREZ approach where renewable development zones were created for transmission investments
■ **Group Study Process:** Projects evaluated in groups, costs allocated on per MW basis at the substation level for distribution upgrades	Consistent with current group study process in Massachusetts and other states
■ **Cost Treatment:** Separate treatment of transmission-level costs and distribution-level costs	Similar to FERC approved cost allocation of PSCo's transmission investments in Colorado which includes separate treatment of varying upgrade costs
■ **Cost Certainty**: Future payments by additional projects are made at same level as initial projects	Achieves benefits similar to cost certainty provisions currently implemented in Massachusetts and California
■ **Post-Upgrade Cost Recovery:** Costs recovered from projects interconnecting in the future	Similar to New York's Post-Upgrade Reimbursement and Massachusetts Group Study but with enhancement for cost certainty for all projects in a zone
■ **O&M Cost Responsibility:** Customers responsible to pay O&M costs on an ongoing basis	Similar to Cost of Ownership charge approved for San Diego Electric & Gas (California)
■ **Cost Recovery Mechanism:** Cost recovery of incremental utility investment would be tracked through a reconciling factor, which would decline over time as new projects enroll in each zone	Consistent with provisions for recovery of other expenditures that are incremental relative to current practices

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Conclusions

1. Cost-causer pays is the most common approach.

- The approach ensures costs are recovered consistent with how costs are incurred.
- However, the method raises 'Free Rider' concerns where one project pays for upgrades that provide benefits to other projects. The method may also result in delays due to prohibitive upgrade costs for DG developers.

2. There are several approaches to address "free rider" concerns.

- A common approach to address 'Free Rider' concerns is having group study processes where multiple projects share costs. This method is currently implemented in Massachusetts, as well as in other states such as California, Colorado, and New York.
- There are several variations of this approach: payment upfront or reimbursement as new projects become online.
  - New York has approved an innovative approach termed as the 'Post-Upgrade Reimbursement' method in which first project pays all costs and is later reimbursed as other projects interconnect. While the approach may streamline the interconnection process, the first developer is still responsible for upfront capital.
- While the group study processes address the 'Free Rider' concern, they may not sufficiently improve project economics in cases where system upgrade costs are unusually high.

3. Cost allocation methods also consider separate treatment of costs related to electric grid improvements.

- Approach is currently applied in Massachusetts, California, and Hawaii for distribution interconnections, where upgrades that benefit all customers are recovered through rate base.
- Hawaii Rules also allow credits to developers in case the interconnection upgrades result in deferral or replacement of planned distribution system upgrades. This is similar to the allowance for "System Improvement" cost allocation for Massachusetts EDCs.

Conclusions (cont.)

4. **State mandates (e.g., Renewable Portfolio Standards) have played an important role in driving transmission interconnection cost allocation methods that reduce the burden on renewable projects.**
   - For example, the MISO "postage-stamp-to-load" cost allocation began developing in 2009, in recognition of the need to identify a set of value-based transmission projects that would enable utilities to meet their Renewable Portfolio Standard (RPS) mandates.
   - Similarly, the ERCOT CREZ cost socialization was also established, in part, to support achievement of Texas RPS.

5. **There are potential approaches that may improve DG project economics.**
   - Costs may be shared across customers and developers based on who benefits.
     - For example, costs related to system upgrades that benefit ratepayers are recovered through rate base in California, Hawaii, and Massachusetts.
     - Cost socialization is applied in some transmission investments, particularly in MISO and ERCOT, which reflects that the transmission benefits are shared by everyone in the region.
   - Pre-emptive upgrades may result in a reduction in developer costs as upgrades may create more capacity than the project needs.
   - One key concern with these approaches is on how to align the benefits with cost responsibility and potential impacts.

Appendix B – Company's Current Cost Sharing Practice

Parameters	Current Cost Sharing Practice for Facilities greater than 25kW	Current Cost Sharing Practice for Facilities 25kW or less
1. Applicability		
a. Eligible Customers	DG and Load customers served by the Company's distribution system	Currently Cost Causation principle applies, i.e., responsible customer pays for system modifications they trigger
b.Eligible Technologies	All eligible technologies governed by Interconnection Tariff M.D.P.U 1320	
c. Common System Modifications	Cost sharing applies **to all distribution, substation and transmission level system modifications** used by more than one customer. It does not cover Facility specific system modifications that are required for the project.	
d. Minimum System Modification Cost Threshold	There is no threshold.	
e. Payment of the Common System Modifications Cost	The initial project ("first mover") pays 100% of the total system modification costs, including the Facility specific costs, in accordance with Interconnection Service Agreement.	
2. Cost Sharing for subsequent customers		
a. System Size limit	Any subsequent project that is **greater than 25kW** in size at point of common coupling and uses the common system modifications will share the common cost	N/A
b.Project Aggregation by single Developer	The situations are handled on case-by-case basis	
c. Prorata share	Prorated share is calculated using nameplate rating (AC) of the project as defined in Interconnection Tariff and divided by total nameplate rating (AC) of all Facilities benefitting from common system modifications.	

	The prorated share of the common system modifications is calculated only when Company receives 100% payment from first mover and/or any other customer who has paid 100% towards such common system modifications.	
3. Cost Sharing Refunds		
a.Maximum Capacity	There is no limit.	N/A
b. Cost Sharing Threshold	There is no threshold.	
c. Cost Sharing time limit	The cost sharing for the common system modification will stop 5 years after the effective date of Interconnection Service Agreement.	

Appendix C: Summary of Two Illustrative Case Studies

The Company offers two illustrative case studies of how the CUPZ allocation methodology and Factor would work, recognizing that there is substantial additional detail that will need to be developed, and added to the Interconnection Tariff, to be finally applicable to Large DG Facilities.

Example 1[12]

In Scenario 1a, which is based on one of the Company's ASO study areas, there are four affected substations, along with both transmission substation and line costs. For the example, to slightly simplify the presentation, all of the substations are assumed to be in the same PSA, and the Facilities would share costs according to the Transmission Cost Allocation method based on MW ratio of the project to all proposed Facilities equally. Distribution costs would be allocated across all of the enabled capacity at each substation. Any cost for unused capacity at a substation would be allocated to the Company to invest in, and this investment would then generate a revenue requirement that would be collected via the CUPZ Factor. A summary of the total capacities and costs for Example 1 is shown below.

[12] Where system modifications that enable capacity are interdependent among several substations within a power zone, the total cost of system modifications at those substations will be evenly split to the total enabled capacity at those substations.

Scenario 1a.	Used Capacity	Enabled Capacity	D Cap Total (millions)	Dx $/kW	T Cap Total (millions)	Tx $/kW	Total $/kW
Sub 1	25.37	42.82	$ 12.1	$ 280	$ 14.8	$ 498	$ 778
Sub 2	24.95	51.31	$ 2.2	$ 42	$ -	$ 498	$ 540
Sub 3	11.42	77.49	$ 36.7	$ 473	$ 22.9	$ 498	$ 971
Sub 4	14.00	18.69	$ 0.7	$ 36	$ -	$ 498	$ 534
Totals	75.74	190.30	$ 51.5		$ 37.7		

As can be seen, the allocation methods differ between transmission and distribution costs. Looking at the distribution costs more closely, certain substation upgrades would have much higher costs per enabled kW than others. Applying the proposed cost cap of $400/kW, the upgrades at Sub #3 would not be eligible for utility cost sharing under the CUPZ proposal. As this would result in a distribution cost of approximately $3,200/kW to the remaining capacity proposed, plus their share of transmission costs, these Facilities are highly likely to be withdrawn. If so, both the distribution and transmission costs associated with the Sub #3 upgrades would be avoided. This would result in cost sharing as shown below in Scenario 1b.

Scenario 1b.							
	Used Capacity	Enabled Capacity	D Cap Total (millions)	D $/kW	T Cap Total (millions)	T $/kW	Total $/kW
Sub 1	25.37	42.82	$ 12.1	$ 280	$ 14.8	$ 229	$ 510
Sub 2	24.95	51.31	$ 2.2	$ 42	$ -	$ 229	$ 271
Sub 3	0.00	0.00			-		
Sub 4	14.00	18.69	$ 0.7	$ 36	$ -	$ 229	$ 265
Totals	64.32	112.82	$ 14.9		$ 14.8		

As shown, the costs overall are reduced for all remaining Large DG Facilities due to lower zonal costs from transmission upgrades. In addition, the Company would invest in distribution System Modifications that create capacity for future Large DG Facilities to interconnect that would be created due to design standards and electric system component form factors (not a preemptive increase in size for any unknown future capacity) and would make that capacity available to future Facilities in each area of the CUPZ at the same cost as was charged to the initial Facilities at that substation. The Company in this case would make an investment of approximately $6.2 million and recover an initial annual revenue requirement of approximately $800,000 through the CUPZ. On an ongoing basis, distribution O&M would be assessed to the connecting Facilities annually, along with transmission O&M charges. The distribution O&M associated with unused capacity component supported by the CUPZ Factor would be recovered through the Factor as well. As additional Facilities enroll in the CUPZ over time, their CIAC payments would both refund customers for depreciated capital already collected via the Factor, and reduce invested capital remaining from the Company, thus lowering the future annual CUPZ Factor recovery amount.

Example 2

In Scenario 2a., again four substations are involved in a study area, and are assumed to be in the same PSA. Distribution costs would be assigned to enabled capacity at each substation, and transmission costs assigned to the PSA would be shared on a MW ratio basis across the PSA, for simplicity, same as in Example 1. As the planning engineers review the needed upgrades, they determine at both the transmission and distribution levels that 50% of each of the costs are already part of the capital plans of NEP and the Company, respectively, and can be classified as System Improvements. This would lower the cost of the upgrades at the transmission and distribution levels by 50% to the Large DG Facilities proposing to interconnect.

Scenario 2a.	Used Capacity	Enabled Capacity	D Cap Total (millions)	D $/kW	T Cap Total (millions)	T $/kW	Total $/kW
sub 1	12.00	12.60	$ 18.8	$ 1,490	$ 16.8	$ 940	$ 2,430
Sub 2	1.35	23.35	$ -	$ -	$ -	$ 940	$ 940
Sub 3	17.29	36.29	$ 7.1	$ 197	$ 9.0	$ 940	$ 1,137
Sub 4	4.99	9.99	$ 5.6	$ 561	$ 7.7	$ 940	$ 1,501
Totals	35.63	82.23	$ 31.5		$ 33.5		

The Company would then apply the CUPZ cost allocation to those costs it might invest in for unused capacity created by distribution upgrades. The Company would apply the same cost cap as in Example 1 and not invest in Sub #1 improvements, as they would be more than $400/kW even after System Improvement allocation. This would make this project ineligible to participate in the CUPZ and the 12 MW proposed at that location would likely not move forward. After adjusting for this attrition, and the reduction in transmission costs due to the removal of Sub #1 upgrades, the projects would have costs to interconnect that are overall lower, as shown in Scenario 2b. summary below.

Scenario 2b.							
	Used Capacity	Enabled Capacity	D Cap Total (millions)	D $/kW	T Cap Total (millions)	T $/kW	Total $/kW
Sub 1	0.00	0.00	$ -		$ -	$ 353	
Sub 2	1.35	23.35	$ -	$ -	$ -	$ 353	$ 353
Sub 3	17.29	36.29	$ 3.6	$ 98	$ 4.6	$ 353	$ 452
Sub 4	4.99	9.99	$ 2.8	$ 280	$ 3.6	$ 353	$ 634
Totals	23.63	69.63	$ 6.4		$ 8.3		