Pope Energy

May 28, 2021

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

dpu.efiling@mass.gov
peter.ray@mass.gov
Katie.Zilgme@mass.gov

D.P.U. 20-75

Pope Energy Reply Comments – Distributed Energy Resource Planning and Cost Assignment, D.P.U. 20-75 Procedural Notice, Request for Comments, and Information Request

Submitted by Doug Pope, President

Dear Secretary Marini:

We continue to be appreciative of the Department's engagement in investigative proceedings involving non-EDC participants in dockets that otherwise would be litigated proceedings excluding direct participation of stakeholders such as ourselves who are needed to execute the yet-to-be finalized 2025 and 2030 Clean Energy Climate Goals.

The Global Warming Solutions Act of 2008 (GWSA) and *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy*, just signed into law by Governor Baker in 2021, charges EOEEA to create and enable renewable generation and reductions in the building and transportation sectors to 85% net zero from 1990 levels by 2050 with 50% of that total being accomplished by 2030. Through the Secretariat, the legislature has charged the Department to enable solar and other DG to meet the climate and emission reductions goals. Enabling means that the process to commercial operation for the emission reductions technology needs to be economic. In the case before the Department, interconnection to the grid needs to be enabled to be timely, dependable and economic; otherwise, the Interim 2030 CECP as written, and 2050 Next Generation Roadmap goals will not be met.

The Department has identified three discrete topics of its investigation:

(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 the EDC's system-planning analysis to develop capital investment project proposals would entail; and

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

Response to (1): Yes. The *Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (2021) places a 30-year obligation on the Commonwealth to reduce emissions 50% from 1990 levels by 2030 and 85% by 2050. The straw proposal proposed by the Department only envisions a 10-year system planning level which, given the choppy interconnection and program for solar and other DG, this 10-year planning window is grossly inadequate to meet the task at hand. The EDCs have described concern over substation-to-substation overload and two-way flow of electrons back onto the transmission system. Substations, the lines between substations and the connections to the transmission system should be built for a 20-year compliance obligation with the Next-Generation Roadmap Act of 2021. These assets would be financed and billed to the ratepayer over 40 years, hopefully using tax-exempt debt.

Current Construct:

Currently, 30.44% of all substations in the EDC territories are congested to the point of requiring a represented 3- to 5-year construction build cycle for substation and transmission upgrades. Geographically, this congestion footprint represents more than half of all the land in Massachusetts.[1] Using the existing knowledge gained over the years of interconnecting DG, the existing interconnection queue, future system planning must start with improvements required today and planned through 2040. This will be known as **Phase II**. **Phase I will be an interim program** to bridge the next five years that will be required to bring solar installations of all sizes and other DG to commercial operation.

In **Phase II,** removing the transmission and substation-to-substation thermal, voltage and reverse power flow constraints with **20-year rated assets would enable** the concurrent installation of solar, other DG and the electrification of the building and transportation sector which is forecasted to double or triple existing Massachusetts electricity consumption.

[1] https://sites.google.com/site/massdgic/home/interconnection MassDGIC: Interconnection in Massachusetts

The annual 10-year assessment as advocated by the Department, would then be dealing with the concurrent, dynamic power flow conditions of the growing adoption of 750,000 EVs, 1 million heat pumps in buildings and increasing levels of solar + storage in the residential, commercial rooftop and larger up to 5 MW utility scale type projects. Impact studies would still be required but Area Studies and Transmission Studies would not be required, because the bulk impediment to interconnection would be removed.

Phase I – An Urgent Challenge

The urgency of the challenge requires an interim step in the distribution planning process envisioned by MA D.P.U. 20-75.

To meet Stat. 2016 c. 75 § 11 and the additional 5% emissions reductions added on by the legislature in *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (2021) to the Interim 2030 Clean Energy and Climate Plan and representations of EEA, the Department, within the constraints of reliability, needs to direct the EDCs to deliver in 6 months, the best plan to enable the continued backlog of completed applications and anticipated applications through 2025. This process will be **Phase I**.

We urge the Department to consider:[2]

1. Leveraging existing and ongoing regional and local transmission studies, distribution area studies, and interconnection studies to assist in enabling interconnection of all size projects in Phase I.

2. An in-depth evaluation of existing capital plans that would enable additional renewable capacity in Phase I through 2025.

Learning From Experience in New York:

In New York the Public Utilities Commission ("New York Commission) initiated "*Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act" (issued and effective May 14, 2020).* In the order the New York Commission directed the New York utilities to identify the level of infrastructure required to meet CLCPA targets. Specifically, the "Utility Study" required the evaluation of the following:

1. Evaluate the local transmission and distribution system of the individual service territories, to understand where capacity "headroom" exists on the existing system;
2. Identify existing constraints or bottlenecks that limit energy deliverability;

[2] Phase I concept assistance and all of the New York experience provided by Kathryn Cox-Arslan of Borrego Solar Systems.

3. Consider synergies with traditional Capital Expenditure projects - drivers of synergies could include aging infrastructure, reliability, resilience, market efficiency, and operational flexibility;

4. Identify least cost upgrade projects to increase the capacity of the existing system;
5. Identify potential new or emerging solutions that can accompany or complement traditional upgrades;
6. Identify potential new projects which would increase capacity on the local transmission and distribution system to allow for interconnection of new renewable generation resources; and
7. Identify the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points.

Of particular note in the final plans issued on November 2, 2020, in the “Utility Transmission and Distribution Investment Working Group Report” issued on November 2, 2020, was the identification of Phase 1 projects that included circuit rebuilds at higher operating voltages, replacement of existing transformers with higher capability equipment, addition or capability upgrades of Phase Angle Regulators (PARs) or series reactors, each of which help control and balance flow on the power system, and replacement of limiting equipment that restricts overall transfer capability.

On February 11, 2021, the New York Commission issued an order finding:
“...based on the Report, the comments, and Staff’s input, that Phase 1 projects present an important opportunity to support CLCPA objectives. Therefore, the Commission directs the Joint Utilities to proceed with development of the Phase 1 LT&D projects which have been incorporated into the Utilities’ capital planning processes and rate plans. To the extent proposed projects are not included in rate plans, they shall be included, with supporting information, in the Joint Utilities’ next rate filings. If projects are needed to meet CLCPA deadlines sooner than can be achieved through a utility’s next rate filing, the utility may file a separate petition, as previously discussed. However, the utility should consider whether projects can be reprioritized within its current budgets before filing a petition for additional cost recovery.”

The acceleration of infrastructure modifications that would have otherwise been performed for reliability or safety compliance represent a significant step in identifying additional clean energy capacity benefits. This may be a valuable interim but foundational step that allows for near to mid-term progress towards our MA climate goals; and can advance prior to the EEA’s initiation of the decarbonization roadmap.

Ten-Year Forecasts Are Self Limiting:

The Eversource proposal submitted on April 23, 2021, under Non-Wires Alternative Framework, Version 2.0 written by Gerhard Walker, Attachment 2, Page 5, Systems Forecast, Lines 104-112, describes the difficulty of having only a 10-year forecasting horizon.

SYSTEM FORECAST HORIZON

The System Forecast Horizon describes the timeline over which the EDC can forecast load and generation growth on their system. The NWA Framework assumes a 10-year System Forecast Horizon. Within that 10-year horizon the utility can provide a load growth and DER adoption forecast which allows determination of the expected system peaks. Capacity deficits can only be determined within that 10-year forecasting horizon. As a result, traditional and DER investments can only be made within those ten years. The NWA Framework does not concern itself with the forecasting methodologies but takes a completed forecast as an input for each of the ten (10) years.

The System Forecast Horizon is set at the Base Year + 10 years. The Base Year describes the last year with a complete annual timeseries data set using 15-min interval data.

Once outside of the Phase I interim solution, a 10-year forecasting horizon will result in the ratepayers paying two to three times to revisit the same substations, feeders between substations, transmission lines and connections every ten years, possibly stranding assets because they should have been larger upon initial installation. It would be more efficient to install major infrastructure once for 20 years and make adjustments in the final ten years after 2040 once the EDCs have had 20 years of significant, concurrent installation of DG, 1.5 million EVs and 2 million heat pumps. Those 40-year assets will be amortized and billed to the ratepayer on a 40-year schedule, thereby not becoming involved with ratepayers paying full value for assets not currently utilized.

To continue to allow constraints on substations and their interaction with transmission will be to accept the current choppy 1- to 5-year interconnection process as acceptable, which it is not; Massachusetts will never hit its emission reduction goals if this condition persists.

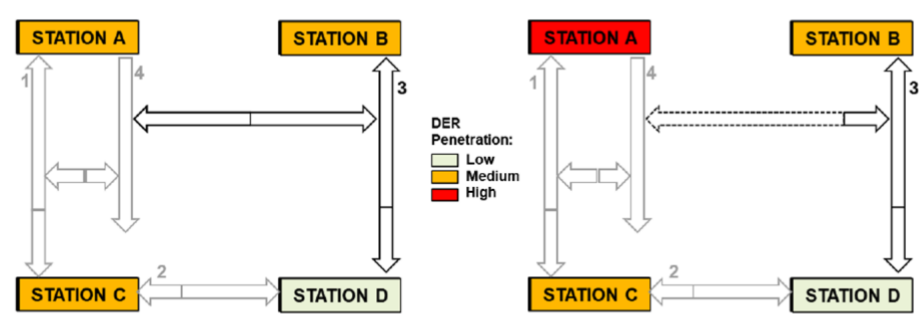


Figure 3. Operational Challenges at Distribution Feeder Level

42, Eighth Street, Suite 4413, Boston, MA 02129
1-617-337-0199, doug.pope@popeenergy.com www.PopeEnergy.com

To relieve choppy policy implementation and ineffective achievement of emission reductions installations, 20-year investments must be made at the substations, between substations and as those substations connect to transmission. Undoubtedly, this will cause transmission upgrades as well. With this 20-year 2050 Decarbonization Roadmap capacity established, the annual 10-year rolling assessment will be dealing with feeder, instrumentation, protection, VAR, security and related issues regarding the concurrent installation of DG, storage, EVs and heat pumps. The cost of the 20-year 2050 Roadmap capacity infrastructure will be rate-based and should be amortized over 40 years.

Eversource, in their previous submittal on D.P.U. 20-75, EDC-5, refers to a **"regulatory asset**" being set up to deal with FERC compliance. On Attachment 2 of the Eversource System Planning Memorandum, line 514, Eversource has stated that their nominal discount rate is 3.37%[3] based upon the Amended AESC 2018 report by Synapse Energy Economics.[4] Our point here is not to discuss the mechanics of interest, but rather, could this **"regulatory asset"** also be used as a conduit to qualify for tax-exempt debt to benefit ratepayers? The Department, the ratepayer advocate, EEA, DOER and other policy makers make decisions on cost; our position is to keep 30-year 2050 Decarbonization obligations as low as possible, while enabling the concurrent emission reductions resources of solar and other DG, EVs and heat pumps.

System Planning and Modeling:

In all of the EDC filings relative to D.P.U. 19-55 and D.P.U. 20-75, in response to this Hearing Officer Memorandum due May 28, 2021, this is the first time that the EDCs have included, with any significance, reference to the *Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (2021) and the Interim 2030 Clean Energy Climate Plan and related emission reduction obligations.

On June 15, 2018, National Grid published their Northeast 80x50 Pathway which is a "paper that presents National Grid's integrated blueprint for New York and New England to reduce greenhouse gas emissions deeply below 1990 levels."

Despite acknowledging the responsibility of complying with existing regulations and legislation, National Grid has based all of their planning processes and recommendations in D.P.U. 19-55 and D.P.U. 20-75 upon **completed applications** which means up to date ISA payments no matter how long group or ASO studies take to complete.

Despite the acknowledgement of *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (2021), Eversource remains committed to **completed applications** in its interconnection queue.

- "Business-as-usual process for developing the 10-year forecast and peak demand. This is based directly on the prevailing DG interconnection queue and load growth queue that has existing work order factoring in average attrition rates. This will provide an adequate planning goal for years 1-3 since

[3] Eversource, D.P.U. 20-75 System Planning Memorandum,
[4] https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf , Page 345

the new business load and DER are well defined, but not as well defined after year 4."

- "Accounting for region specific economy, policy, and technology changes. This scenario reflects what local and/or state policies will consider ambitious but achievable goals. Additionally, DER adoption and new business loads are forecasted based upon previous historical growth over 10 years at the local level. In general, this Scenario provides adequate planning goals for years 4-10."[5]

Measuring solar PV interconnection demand based upon completed applications on a congested system with large portions of an EDC's territory is modeled after the existing, old and constraining cost causation model. The interconnection of solar PV and other DG needs to be modeled upon targets that should be **enabled** to meet emission reductions requirements. The EDCs need to be directed to install a certain number of MW per year. In Undersecretary Judy Chang's remarks,[6] she mentioned 500 MW of solar would need to be procured per year with yet another 2 GW of solar that had yet to be defined that needed to be installed by 2030 to meet the 45% emissions reductions, not the 50% as required by the legislature. The above totals do not include the balance of the 1,600 MW in the SMART program that have not been built. The Brattle Group report indicates that a minimum of 1 GW of solar needs to be installed per year to meet the 2050 emission reduction requirements.

The EDCs, particularly Eversource, have spent significant time describing modeling considerations. The modeling conclusion made by the EDCs may end up preferring to install a 20-year capacity integrated substation/transmission system upgrade which we call Phase II, **enabling** not only solar and other DG but the electrification of the transportation and building sectors.

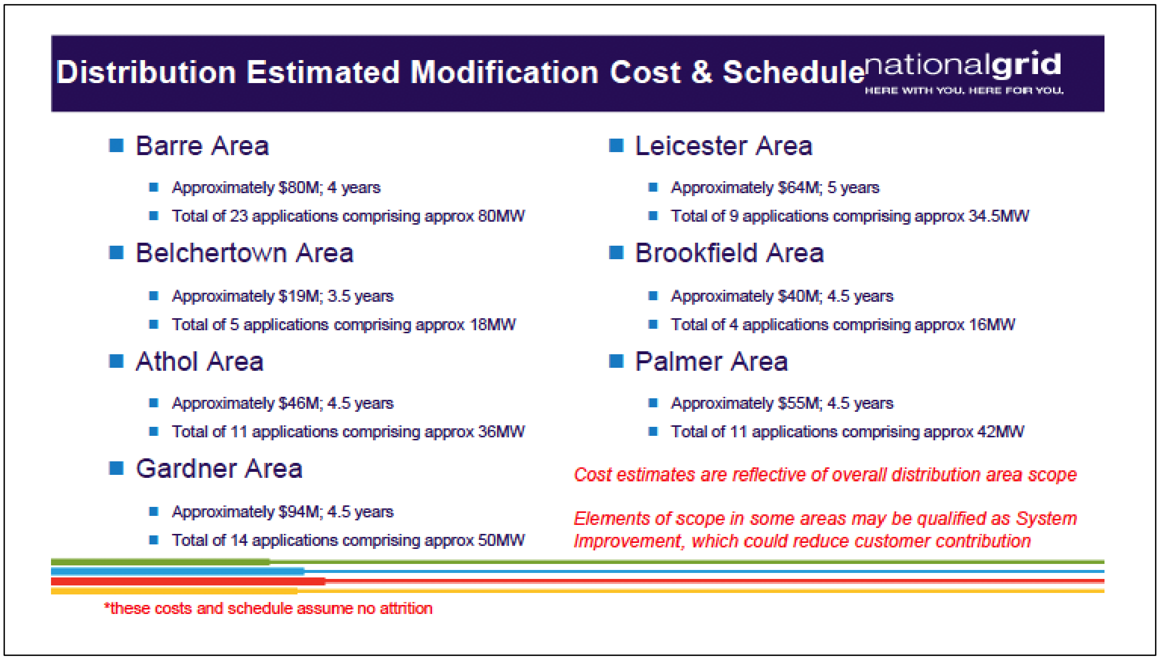
The modeling of projected demand by the EDCs will be completed with cutting edge modeling software and capable staff. But the individual feeders will be subject to varying degrees of accuracy as the occurrence of DG, EVs and heat pumps on the system will not be uniform, nor meet the neat requirements of a model. The system planning will be made for the benefit of shared beneficiaries in the generation, transportation and building sectors as require by legislation.

If the Department maintains its insistence on a 10-year rolling planning assessment, most of Massachusetts will be congested until 2025, capacity will open up for 2-3 years and be constrained again in 2028 and beyond, until new capacity is installed. Lessons will not have been learned and not much will have changed since 2010, despite having a 50% emissions reduction requirement enacted into law. See below National Grid's yet-to-be updated substation upgrade schedule and MassDGIC Interconnection Circuit Saturation Totals map as illustrations as to how pervasive the congestion problem is currently in Massachusetts. A **Phase I** solution must be demanded of the EDCs by the Department.

---

[5] Eversource, D.P.U. 20-75 System Planning Memorandum, 4.5.2

[6] Clean Energy and Climate Plan for 2030, Judy Chang Undersecretary of Energy, EEA March 9, 2021, Page 8 (Zoom type webinar)

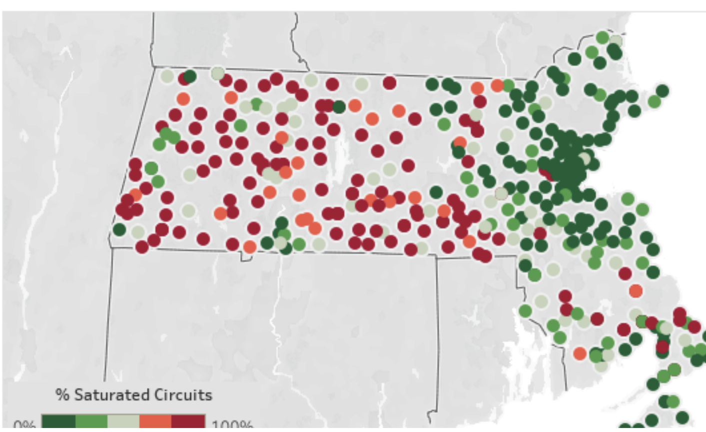


MassDGIC: Interconnection in Massachusetts, Circuit Saturation Totals Map [7]

Circuit Saturation Totals

	% of Circuits		Number of Circuits	
Utility	Not Saturated	Saturated	Not Saturated	Saturated
Fitchburg	100.00%		37	
National Grid	63.54%	36.46%	805	462
NSTAR	79.69%	20.31%	922	235
WMECO	45.91%	54.09%	101	119
Grand Total	69.56%	30.44%	1,865	816

Circuit Saturation by Town



Filter for utility and town below, or by clicking on a town on the map:

Utility
(All)

Town
(All)

---

[7] https://sites.google.com/site/massdgic/home/interconnection MassDGIC: Interconnection in Massachusetts

As the Department considers the management aspects of the proposals provided by National Grid and Eversource, think of the management structure that will be involved to manage a constrained interconnection queue. Think of the time of both the EDCs and the DG community in dealing with a convoluted system that is designed to hold back demand that is required by legislation.

If the interconnection cost for DG is on a defined $/ kW basis, there will be no investment in a constraining, bureaucratic process paid by the ratepayer; ratepayer funds will go to reducing emissions. Impact Studies will still be required, the queue will be managed on a first-come, first-served basis, and cost will be defined. Phase I will provide a pathway for emission reduction through 2025 and Phase II will provide a pathway for unimpeded concurrent installation of renewable generation and the electrification of the building and transportation sectors.

There needs to be a fire-in-the-belly kind of urgency in developing **Phase I** solutions. If a Class 5 hurricane had a direct hit on eastern Massachusetts and flying debris wiped out all the substations and transmission lines, what plans are in place to get the most productive state per capita back in business?[8] The Department needs to depart from a business-as-usual timeframe work to delivering effective solutions in Phase I.

Phase I and **Phase II** will have ratepayer impacts. The legislature is forcing transformative change, but that change is not without benefits. According to the Energy Pathways Report, "*wind and solar generation, (are) the least-cost forms of electricity supply*"[9] and the Economic and Health Impacts Report, Page 5, states the following:

*"Maximizing in-state spending while minimizing total cost result in stronger economic performance across employment, income and output indicators. For example, the least-cost pathways (All Options, Regional Coordination, and DER Breakthrough**) all experience returns in terms of economic output that are greater than three dollars per dollar spent** – levels that are higher than direct investment in impacted industries because such investment reduces the need for, and total cost of, energy imports. Approximately 472,000 job-years[1] are created by investment in the benchmark decarbonization pathway (All Options) over the course of 30 years, translating to an average of 15,000 jobs annually.[10]*

Stakeholders represented by the Associated Industries of Massachusetts (AIM) and like retail and manufacturing sectors will rightly question making 20-year investments in transformative infrastructure improvements ahead of current requirements. However, the best way for AIM and like commercial, industrial and manufacturing stakeholders to lower their electricity bills and mitigate 2030 CECP and 2050 Decarbonization emissions

---

[8] https://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_GDP_per_capita

[9] Energy Pathways to Deep Decarbonization, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, December 2020, Page 52

[10] Economic and Health Impacts Report, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, December 2020, first bullet, Page 5

reductions requirements is to actively participate in renewable generation directly through behind the meter installations, rooftop leases or Community Solar participation.

The best way for the Department to address the requirements of these stakeholders is to enable the timely and unimpeded execution of contracts to acquire use of technologies that reduce emissions in the generation, transportation and building sectors.

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

Response: Yes. On May 13, 2021 at 5:39 PM, EEA Secretary Kathleen Theoharides sent an email to all 2030 CECP Commentors and Stakeholders stating that EEA, in accordance with the requirements of *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (2021), the emission limits, sublimits, and carbon sequestration baseline and goals will be finalized by July 1, 2022 and will have the force of law.[11]

Given that D.P.U. 19-55 intended to expedite a decision-making process relative to interconnection to keep solar projects from falling out of the queue and that the Department and all stakeholders have to wait another 13 months for policy direction from EEA, the Department should, as allowed by department in the Commonwealth, declare **emergency regulations** to be promulgated to last for 25 months and set interconnection fees at a $/kW rate in accordance with the fee schedule listed below.

This will allow EEA, as required by the legislature, to finish the final version of the 2030 Clean Energy and Climate Plan, with three months' time for the EDCs to make adjustments to their capital plans in conformance with the 2025 and 2030 CECP and nine months for the Department, to adjudicate if necessary, a tariff for D.P.U. 20-75. Upon issuance of the 2025 and 2030 CECP in July of 2022, which will have the force of law,[12] the Department will be in a better position to evaluate the impacts of the pathways to a 50% reduction from 1990 emissions levels by 2030.

We believe that the Department should instruct the EDCs to plan on system planning for 500 MW of DG per year until 2025 and gaining 100 MW per year until 2030 when 1 GW of DG will be installed per year until 2040. See the Brattle Group Executive Summary in Exhibit 1. These installation rates are also consistent with our Comment Letter on the Interim 2030 CECP available here.[13]

The interconnection of solar and other DG has costs, and those costs have been captured by National Grid data collection of the average cost of interconnection mentioned above and the SMART investigation conducted by SEA on behalf of DOER, see attached Exhibit 2; the ratepayer advocate has ample evidence that the ratepayer

[11] EEA Presentation 2050 Roadmap Building Solutions to Address Climate Change in the Commonwealth, April 1, 2020 siting Kane vs. DEP, Page 5

[12] EEA Presentation 2050 Roadmap Building Solutions to Address Climate Change in the Commonwealth, April 1, 2020 siting Kane vs. DEP, Page 5

[13] https://www.popeenergy.com/wp-content/uploads/2021/05/POPE_ENERGY_COMMENT_LETTER_2030_CECP_3-22-2021_final.pdf

42, Eighth Street, Suite 4413, Boston, MA 02129
1-617-337-0199, doug.pope@popeenergy.com www.PopeEnergy.com

interest are reasonably protected by the application of these fees for interconnection of solar and other DG emission reduction resources.

As indicated in our comment letter of April 13, 2021, and on May 21, 2021, we agree with National Grid's findings in their response to EDC-3 Page 2 of 3 that states that the average interconnection fee is between $133/kW and $226/kW.

National Grid's findings in this instance validate both the reality on the ground and the efficacy of solar policy that has enabled solar PV for the commercial operation as an emission reduction resource.

Accordingly, consistent with our advocacy in comment letters in D.P.U. 19-55 and D.P.U. 20-75 for project differentiation, we propose the following interconnection fee including point of common coupling cost where the fee is cumulative based on total AC capacity size.

- 5 cents/watt for the first 60 kW AC
- 15 cents/watt for the capacity over 60 and up to 500 kW AC
- 20 cents/watt for the capacity over 500 and up to 1 MW AC
- 21 cents/watt for the capacity over 1 MW and up to 2 MW AC
- 22 cents/watt for the capacity over 2 MW and up to 3 MW AC
- 23 cents/watt for the capacity over 3 MW and up to 4 MW AC
- 24 cents/watt for the capacity over 4 MW and up to 5 MW AC

Longer Term Amortization of Infrastructure Cost:

We are aware that in a Rate Case, longer-term assets are depreciated on a longer schedule. However, the costs of those longer-term assets are aggregated with lesser term assets resulting in an illustrative 10.198% depreciation rate as indicated on Exhibit 3.

There is a trend that seems to exist in practice, and it is confirmed with the Non-Wires Alternative presentation with Eversource under Financial Planning Horizon, Page 5 of pdf Page 89, Line 120, that describes their approach to use the **Shortest Expected Lifespan** as a financial methodology. This make sense when one is depreciating an energy storage system but not a 40- to 60-year transformer.

It is our contention that policy makers are making long-term decisions based upon accelerated costs that do not reflect the useful life of those equipment assets. Hence, we are requesting that the Department hold these transformative infrastructure equipment investments with useful lifespans of greater than 40 years in a separate tariff schedule to inform policy makers of property apportioned cost.

In Summary in D.P.U. 20-75:

1. Promulgate Emergency Regulations for 25 months to allow EEA to issue the final 2025 and 2030 CECP which will further inform the Department.
2. Assign $/ kW cost to interconnect based upon the cumulative schedule above.

3. Instruct the EDCs in their planning to size their systems to 500 MW per year until 2025 adding 100 MW per year until 2030 whereupon 1 GW per year shall be installed until 2040 while waiting for the 2030 CECP to be published.
4. Instruct the EDCs to develop solutions to continue to interconnect DG for **Phase 1** through 2025.
5. Instruct the EDCs to develop solutions for **Phase II** through 2040.
6. Examine the use of 40-year useful life of 2050 Decarbonization equipment assets and separating those assets on a separate tariff.
7. Examine the creation of a regulatory asset to comply with FERC and possibly as a financing conduit for tax-exempt finance debt to benefit ratepayers.
8. Examine the use of tax-exempt debt as means of financing equipment assets that benefit the common good.

We appreciate the fact that the Department has previously said it was not prepared to entertain the larger rate basing of required infrastructure improvements. The Act passed by the legislature this year has advanced the rate-basing issue front and center in a fashion that substantial progress will not be made without addressing the issue affirmatively.

Best Regards,

Doug Pope
President

Exhibit 1

Brattle Group, Achieving 80% GHG Reduction in New England by 2050, September 2019

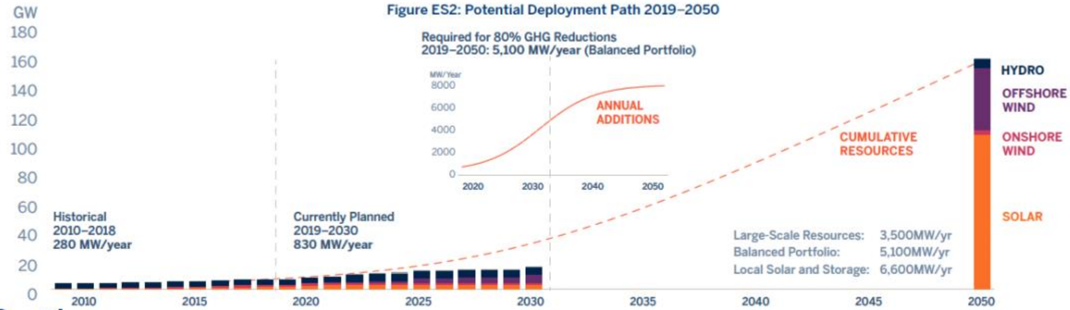
EXECUTIVE SUMMARY

However, adding 800 MW per year through 2050 is not nearly enough. In fact, as shown in Figure ES1, between 2019 and 2050, between 3.5 GW and 6.6 GW of renewable capacity, including 2–5 GW of solar and 2–3 GW of wind, will need to be added each year on average.

Put differently, **New England will need to accelerate annual deployments 4- to 8-fold compared to what is planned for the coming decade.** While that sounds daunting, such ramp-ups are not unprecedented.

As a matter of fact, the acceleration New England needs is in line — if not slower — than the ramp up that wind and solar technologies have seen over the past 20 years. Over that time, annual wind installations globally have grown by over 11% per year on average, and solar PV by close to 41%. By contrast, to reach the 2050 targets in New England, annual installations of renewable projects would need to grow by about 9% per year. The ramp up does not have to happen on day one. Rather, the focus will need to be on mechanisms to keep the collective foot

Figure ES2: Potential Deployment Path 2019–2050



Brattle

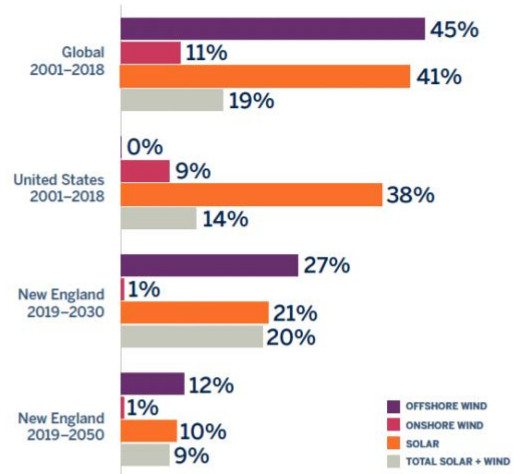
v

EXECUTIVE SUMMARY

on the clean energy accelerator until annual installations approach a level that sustains an entirely new and significant industry based on renewable energy in the future. Assuming that future growth of energy demand beyond 2050 will be modest and a typical renewable energy project will last 25–30 years, New England would need to replace about 4–5% of our facilities every year, or 7–8 GW of capacity each year, after 2050.

The bottom line is that if New England wants to make good on their greenhouse gas emissions reduction goals, they will need to keep their foot on the clean electricity development accelerator over the next critical decades to 2050. The current pace of adding more solar PV, onshore and offshore wind, battery storage, etc., is simply insufficient. However, if New England keeps growing these new industries at roughly the current rate, the region may have a chance to achieve the commitments made to decarbonize our economies by 2050 and do its part to reduce the risks of catastrophic climate change. And, in the process, it will create a substantial and sustainable new green economy.

Figure ES3: Rate of Growth of Annual Additions



Brattle

vi

Exhibit 2

Cost_Data_Entry_040416, Sustainable Energy Advantage as part of a consulting engagement with DOER that was conducted in the feasibility study to establish a tariff for the SMART program. The data below was considered part of the economic feasibility to enable a starting point for the SMART program.

Interconnection Costs ($/W DC)

Interconnection costs include costs relating to connecting to the grid, such as construction of transmission lines, permitting costs with the utility, and start-up costs. This category will also include the cost of a new substation, if necessary.

For each of the project size/type categories below, we provide our initial estimate ("SEA Starting Point") of the typical MA interconnection costs per Watt DC as a reference. Please provide your typical range of costs for each bin by filling in the "Low End of Range" and "High End of Range." For bins which you cannot provide cost data, please write "N/A."

*Project Type Assumptions: **Brownfield/Landfill:** Assume projects < 250 kW would be Rooftop Solar.*

MA Interconnection Costs - $/W DC (2015-2016)

Project Type	<25 kW			25-250 kW			250 kW-1 MW			>1 MW			Range (Low to High)		
	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range
Ground-Mount Solar	N/A	NA	NA	N/A	$0.13	$0.25	$0.11	$0.13	$0.25	$0.11	$0.18	$0.25	**$0.11 - $0.11**	**$0.13 - $0.18**	**$0.25 - $0.25**
Brownfield Solar	N/A	NA	NA	N/A	NA	NA	$0.11	NA	NA	$0.11	NA	NA	**$0.11 - $0.11**	**$0.00 - $0.00**	**$0.00 - $0.00**
Community Shared Solar	N/A	NA	NA	N/A	$0.13	$0.25	$0.11	0.13	0.25	$0.11	0.18	0.25	**$0.11 - $0.11**	**$0.13 - $0.18**	**$0.25 - $0.25**
Landfill Solar	N/A	NA	NA	N/A	$0.13	$0.25	$0.11	$0.13	$0.25	$0.11	$0.18	$0.25	**$0.11 - $0.11**	**$0.13 - $0.18**	**$0.25 - $0.25**
Solar Canopy	N/A	NA	NA	$0.17	0.13	0.25	$0.11	$0.13	$0.25	$0.11	$0.18	$0.25	**$0.11 - $0.17**	**$0.13 - $0.18**	**$0.25 - $0.25**
Rooftop Solar	$0.00	NA	NA	$0.17	$0.13	$0.25	$0.11	$0.13	$0.25	$0.11	0.18	0.25	**$0.00 - $0.17**	**$0.13 - $0.18**	**$0.25 - $0.25**
Low Income Solar	$0.00	NA	NA	$0.17	0.13	0.25	$0.11	0.13	0.25	$0.11	0.18	0.25	**$0.00 - $0.17**	**$0.13 - $0.18**	**$0.25 - $0.25**

It is our assertion that the Department will continue to struggle to find a scientific apportionment of cost for solar and other DG, beyond the table of interconnection cost listed above, due to the aggressive 50% reduction of emissions by 2030 demanded by the legislature and concurrent beneficiaries in the transportation, building and renewable generation sectors.

In the public forum of the TSRG, on May 20, 2021, on a RingCentral meeting, the difficulty in establishing a scientific basis for apportionment of cost was described by the Shahir-Eversource comment in the chat at 03:37 PM. “Distribution System is so dynamic that it is extremely difficult to match exactly what you see in the Software.” So, modeling of coincident emission reduction beneficiaries will be nearly impossible; hence the assignment of reasonable cost on a $/kW basis.

The policy that the Department should establish is that solar PV and other DG are assigned a reasonable cost of $/kW to interconnect, and all other DG and transmission cost are rate-based on a 40-year amortization schedule. The substation-to-substation infrastructure and supporting transmission system should be installed based upon the emissions reduction requirements for the next twenty years. Amortizing those cost over 40 years will not unnecessarily burden ratepayers for requirements that exist in current legislation and will need to be installed anyway. We continue to assert that these improvements should be financed with tax-exempt debt, particularly with today’s low rates. Illustratively, an AA-Rated Muni Bond for 30 years is 1.75% versus the 3.37% or higher offered by the EDCs.

Exhibit 3

Below is a filing by the AGO in D.P.U. 18-150 Performance-Based Ratemaking Proposal, September 30, 2019. The depreciation rate is 10.198% per year while Line 7 is 2.5% per year.

Weighted Average Depreciation Rate for General Assets, 1996

Row	General Assets (In Thousands of Dollars)	Value [1]	% of Total Value	% of Net Value	Lifetime [2]	Declining Balance [2]	Depreciation Rate
6	Land and Land Rights	$489,443	1.96%		NA		
7	Structure and Improvements	$7,085,330	28.35%	34.20%	36	0.89	2.5%
8	Office Furniture and Equipment	$3,744,952	14.99%	18.08%	14	1.65	11.8%
9	Transportation Equipment	$2,436,285	9.75%	11.76%	9	1.73	19.2%
10	Stores Equipment	$182,280	0.73%	0.88%	16	1.72	10.7%
11	Tools, Shop and Garage Equipment	$1,006,533	4.03%	4.86%	16	1.72	10.7%
12	Laboratory Equipment	$800,097	3.20%	3.86%	12	1.62	13.5%
13	Power Operated Equipment	$589,718	2.36%	2.85%	16	1.72	10.7%
14	Communication Equipment	$4,871,143	19.49%	23.51%	11	1.65	15.0%
15	Miscellaneous Equipment	$371,834	1.49%		NA		
16	Other Tangible Property	$3,412,124	13.65%		NA		
17							
18	**Total Value**	**$24,989,739**	100.00%	100.00%	**20**		**10.198%**
19	Unknown Life	$4,273,401					
20	Net Value	$20,716,338					
21	Percent Unknown	17%					

[1] Source: EIA, Financial Statistics of Major Investor-Owned Electric Utilities, 1996

[2] Source: Department of Commerce, "The Measurement of Depreciation in the National Income and Product Accounts", Survey of Current Business (July 1997)