Pope Energy

December 23, 2020

Mark D. Marini, Secretary
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D.P.U. 20-75

Pope Energy Comment Letter – (1) Distributed Energy Resource Planning and (2) Assignment and Recovery Cost for the Interconnection of Distributed Generation

Submitted by Doug Pope, President

Dear Secretary Marini:

We appreciate the Department of Public Utilities opening the investigations of distributed energy resource planning and recovery cost for the interconnection of distributed generation through the use of working group sessions as opposed to a litigated tariff. We believe engaging developers, utilities and public policy stakeholders in deliberative discussions of how to facilitate installation of increasing levels of distributed generation will bring a more collaborative and ultimately faster approach to solving the many hurdles ahead of Massachusetts in achieving its GWSA goals.

Executive Summary

Concurrent renewable policy implementation to encourage wind, solar, storage, and other DG, while electrifying the transportation and buildings sectors, requires too many system-wide infrastructure upgrades to force the assignment of cost on one industry sector, which is primarily the solar industry. Interconnection of renewables is a real property entitlement and interconnected projects should pay for all Point of Common Coupling cost and an interconnection fee, but that fee should be actual cost with a not-to-exceed fee. If actual cost is less than the not-to-exceed fee, that will provide market signals for developers to seek out less congested project locations. Coincident installation of solar, storage, and the thermal conversion of the building and transportation sectors to electricity powered by renewables to accomplish 85% net-zero emissions by 2050 is going to take a system-wide restructuring of our distributed generation system. That reconductoring and redesign of the distribution and transmission system is going to create a free-ridership situation that is not recognized by the D.P.U. 20-75 Straw Proposal and will unfairly burden early interconnectors that are dominated by the solar industry. A fixed interconnection fee of fifteen ($0.15) to twenty ($0.20) cents per watt AC plus Point of Common Coupling cost appears from the research and in the field practice to be a reasonable cost to be assigned (see B-6 SEA chart). Responding to the public policy objective of having solar development respond to market forces, an option to explore would be to use the actual cost of interconnection if that cost is less than the capped, not-to-exceed interconnection cost plus all Point of Common Coupling cost.

Using the actual cost of interconnection, in the instances where interconnection is of less cost than the not-to-exceed fixed $0.15 - $0.20 plus PCC cost, would encourage developers to seek lower cost installations and meet public policy objectives.

Market forces are a function of time, information and expenditure of money. Due to fully congested systems, ASO studies and choppy policy implementation, we do not believe market forces exist on the larger-than-500 kW project level. Investment in renewables in Massachusetts, given its successful management of programs in the past, is driven by faith that, on the way to net-zero by 2050, Massachusetts will do the right thing at the end of the day.

The Department in both D.P.U 19-55 and D.P.U. 20-75 is looking for an interim interconnection solution to bridge the regulatory gap in implementing a pressing need for DG interconnection reform. Establishing a fixed fee or an actual cost, plus all Point of Common Coupling Cost not to exceed ($0.15 - $0.20) per watt AC is that method. The assignment of either method is simple. It requires little Department and EDC administration, little developer process education, and it represents the intent of Chapter 75 of the Acts of 2016 to encourage the continued development of solar-renewable generating sources and to create accurate price signals and market-base mechanisms while supporting diverse installation types.

In order to engage in distributed energy resource planning, the Department, EEA, EDCs, ISO-NE, NESCOE, NEPOOL, transmission companies, developers and all other stakeholders need to know what is being built and on what schedule. How many megawatts of solar and wind does Massachusetts intend to install per year to meet 85% net-zero reduction in emissions by 2050? The decisions made in D.P.U. 20-75 will affect the ability of the Commonwealth to execute the electrification of the transportation and buildings sectors to provide the BTU equivalent of fossil fuels with renewable energy.

Long-term capital improvements should not be avoided because of high cost, but rather those costs should be amortized and billable to the ratepayer on a schedule reflecting the useful life of the asset. If a substation or transmission conductor needs to be replaced and the useful life of those pieces of equipment are 36 years and 50 years respectively, then the ratepayer should only be billed for the current portion of that amortization. The financing decisions made in D.P.U. 20-75 will affect all of the Grid Modernization dockets and will inform such decisions to install smart meters and impose time-of-use rates. Funding provided by the EDCs, authorized under tariff to lower the cost of capital to pay for long-term capital improvements with equipment of a long-life cycle, may need to be substituted with tax-exempt debt either used by the EDCs or structured under a facility funded by the delivery of electricity under tariff.

Establishing a Baseline of Solar, Wind and Other DG Capacity to be Installed Annually

NESCOE Vision Statement October 2020:
ISO-NE has noted in its 2020 Regional Electricity Outlook that, "…even with substantial investment made to modernize the transmission system… system upgrades will be needed to accommodate large amounts of diverse clean-energy sources[.]" [1]

(NESCOE) As a region, we cannot effectively plan for integrating clean energy resources and decarbonization of the electricity system required by certain states' laws without having a clear understanding of the investments needed in regional transmission infrastructure. As we work to develop that understanding, we urge ISO-NE to consider the efficient utilization of the current system while planning for its expansion.[2]

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[1] NESCOE, New England States' Vision For A Clean, Affordable, and Reliable 21st Century Regional Electric Grid, Page 3 & 4

[2] NESCOE, New England States' Vision For A Clean, Affordable, and Reliable 21st Century Regional Electric Grid, Page 3 & 4

Gordon van Welie, President and CEO of ISO-NE presenting at the New England Restructuring Roundtable, has for years effectively said to the New England states, “Tell us what you want to do.” The states have responded with finite programs and ISO-NE has responded only anticipating those finite programs. ISO-NE has not looked at the renewable energy laws, regulations and guidelines in the New England states and made projections as to what might happen; it is not their job.

At great expense of creative resources, time and money, National Grid is proposing a Common Upgrade Power Zones (CUPZ) system (B-4 Page 3) that is “incremental” in nature, is “underpinned by the principal that ‘cost causers’ should pay for the cost they create to interconnect”[3], and relies on “CUPZ price signals” (B-4, C. Page 7) on a mostly congested system. Those congested substations are in less expensive rural areas and National Grid recommends shifting development to suburban areas that are more expensive, time-consuming or difficult to develop. While the cost of interconnection is less, development opportunities for larger solar systems are less available and typically cost more to develop. Consistent with working group representations made in D.P.U. 19-55, National Grid’s proposal is a static condition based upon completed interconnection applications. What happens when new applications follow the static condition? The CUPZ plan is oblivious to the reconductoring, protection and voltage support that will be required to power both the transportation and building sector. Why the omission of these important considerations? They were not requested by the Department to respond to those issues. The old and existing model of handling complex issues as discrete topics fails to adequately respond to the dynamics of transitioning the electric, building and transportation sectors to renewables in a regional electric system.

On December 9, 2020, Attorney General Maura Healey’s ratepayer advocates office held a “Teach-in on New England’s Wholesale Power Markets” that “educated ratepayers on the basics of the mechanics of the wholesale energy markets and called on ISO-New England to set market rules that support cleaner energy resources.”[4]

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[3] B-4 National Grid Cost Allocation Proposal D.P.U. 19-55, February 28, 2020

[4] https://www.mass.gov/news/ag-healey-launches-effort-to-empower-massachusetts-ratepayers-to-advocate-for-a-cleaner-energy

Wholesale markets only respond to the supply and demand of volume. ISO-NE will be able to "set market rules that support cleaner energy resources" once the states have identified how much renewable generation will be generated on an annual basis until 2050.

In September of 2019, the Brattle Group published Achieving 80% GHG Reduction in New England by 2050, which calls for 2-5 GW of solar and 2-3 GW of wind to be installed each year on average. At 45% of ISO-NE load, the Massachusetts share of those installed solar and wind resources would be between 900 MW - 2.25 GW of solar and 900 MW - 1.35 GW of wind per year. See Exhibit 1.

The generation and consumption of this level of renewables will shape the discussion of this two-way power flow from distribution to transmission and possibly the export of the same during shoulder-season periods.

Massachusetts should, through the Governor's office, EEA, DOER and DPU, set a fixed amount of solar and wind to be installed per year. Those decisions will inform and shape the resource planning required to meet the emissions reductions already in law.

Gratefully, D.P.U. 20-75 basically says we need to do resource planning and we are looking for input as to how to pay for it, how cost would be recovered by the EDCs and what would be the impact on ratepayers. While D.P.U. 20-75 is a big, innovative policy jump for the Department, it does not measure up to the task before the Commonwealth in reducing emissions by 2050. The work set in motion between 2020 and 2025 will enable the scaling of renewables and the electrification of the building and transportation sectors from by 2025 and onward.

If D.P.U. 20-75 stated that Massachusetts was going to install one gigawatt (1 GW) of solar and one gigawatt (1 GW) of wind per year, accommodate load for 300,000 zero emissions vehicles, (ZEV's) or 15% of registered vehicles by 2025, adding roughly 5% of registered vehicles[5] per year thereafter and converting 10% of all single-family houses and 5% of all commercial buildings to heat pumps by 2025, and converting an additional 5% to each sector per year thereafter, and asked the EDCs for comments as to how the Department should engage in

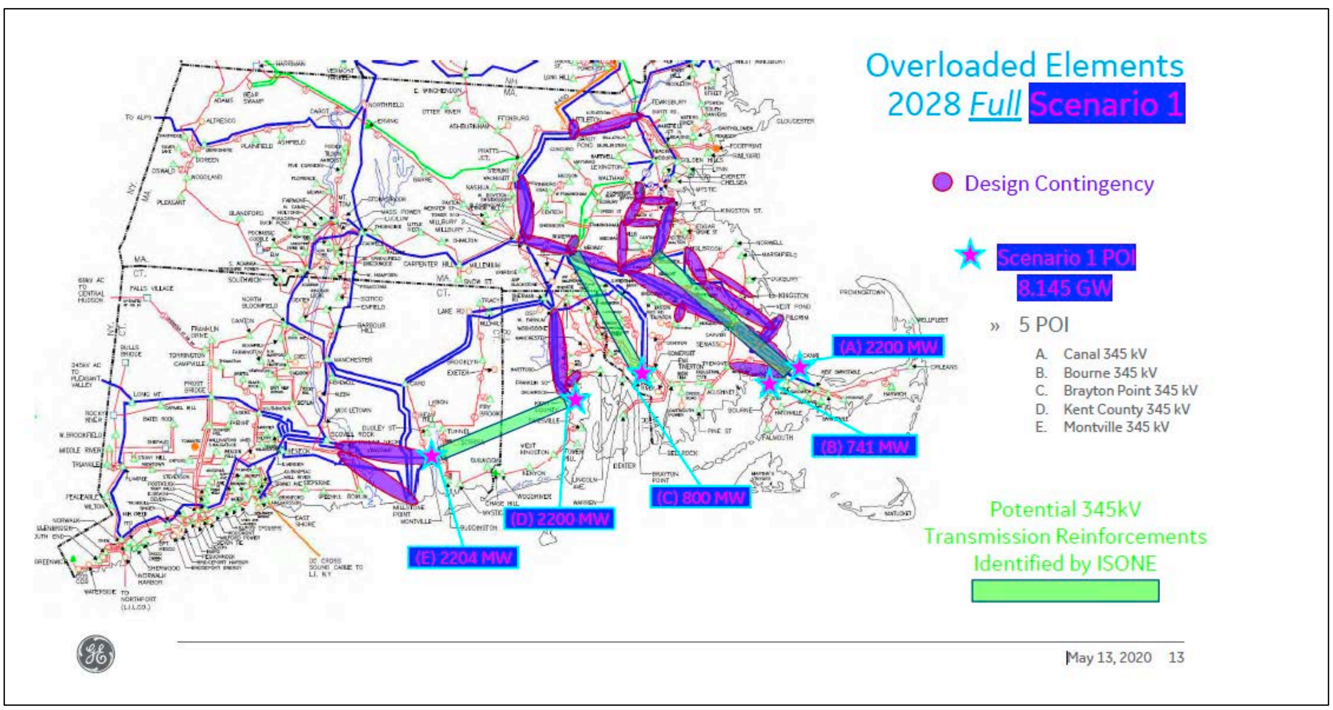
[5] Massachusetts Zero Emission Vehicle Action Plan: A Roadmap to Reach 300,000 Zero Emission Vehicles on Massachusetts Roads by 2025, EEA, August 2015

resource planning and cost recovery, the perspective as to how to approach D.P.U. 20-75 would be totally different. Given the breadth of the inputs, this is why we are recommending either a fixed fee or actual cost of interconnection if lower than a capped, not-to-exceed fixed interconnection fee of fifteen ($0.15) to twenty cents ($0.20) per watt AC.

Solar, Storage, Other DG, Wind, Electric Vehicles, Electrification of the Building Sector Should be an Integrated Solution

In the Offshore Transmission in New England, The Benefits of a Better Planned Grid study as prepared by The Brattle Group for Anbaric on May 2020, subconsultant GE, in their Appendix B (Transmission Security Analysis & Economic Production Cost Simulation), indicate that there will be significant transmission constraints as electricity needs to be pushed north and west.

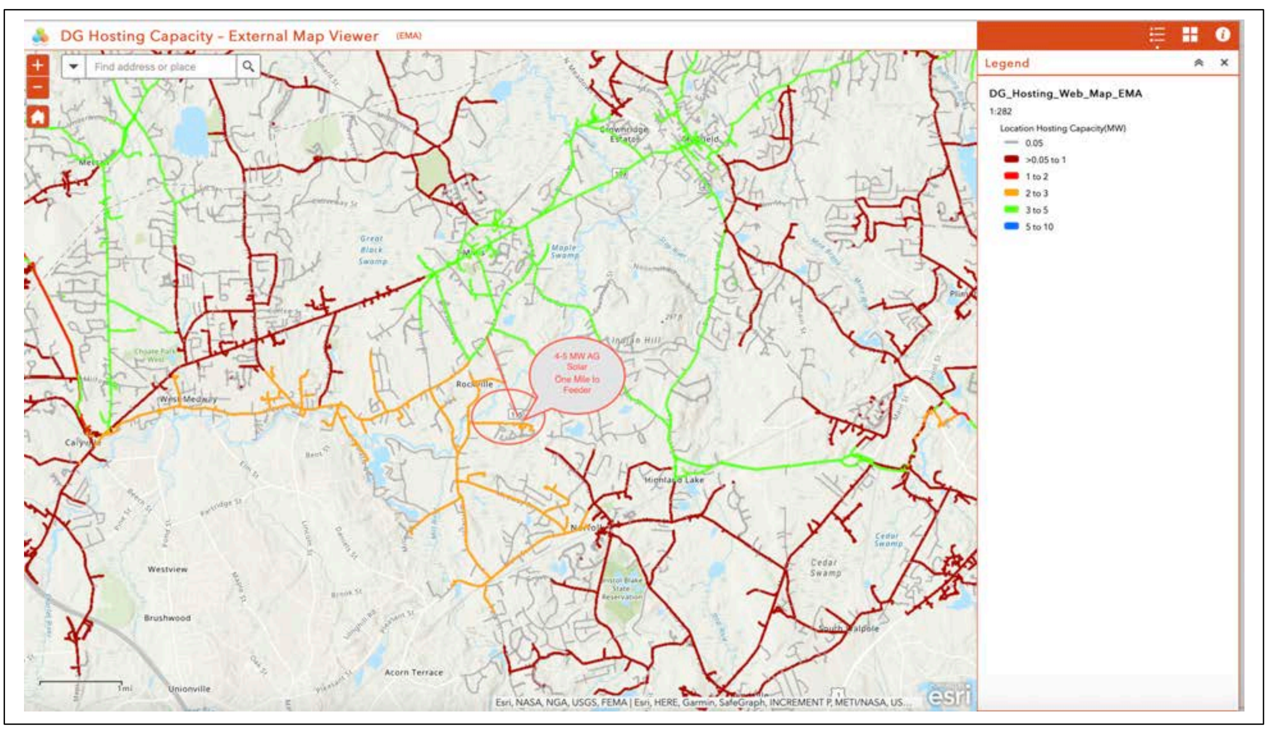
Could this transmission requirement for wind also assist the installation of solar, storage and other DG? Could solar + storage systems store wind energy generated at night and discharge that energy during the early morning hours, particularly during winter? D.P.U. 20-75 needs to have a broader view of integrating renewable generation in the resource planning process.



Could this rebuilt transmission system be used for (paid) export to other states as opposed to curtaining renewable resources?

Real Market Conditions, Market Signals, and Who are the Beneficiaries?

Below is a 4-5 MW Agricultural Solar project in the beginning phases of development in a fairly densely populated community in the Eversource territory superimposed on a utility provided heat map or DG Hosting Capacity Map. This project has not entered the Impact Study phase as of this writing. Given that the feeder shown in green has 3-5 MW in capacity, we expect interconnection cost to be $250,000 for project specific Point of Common Coupling cost, $500,000 to upgrade for one mile, a single-phase feeder to three-phase capable of servicing a 5 MW AC solar + storage generation system and an estimate of $500,000 for circuit and substation protection. That estimate matches up with our fixed fee proposal of $0.20 per watt AC. Since at the time of the pre-application there was only 2,440 kW on the line, there is the possibility that the circuit and substation protection might be less costly, but given the congested nature of all EDC systems, in our view, that likelihood is remote. The upgrade cost could be greatly in excess of our estimate due to all kinds of substation and “transmission-level thermal and stability analysis” conditions. This kind of application may require “telemetry and revenue grade data acquisition.”



Even with a heat map and pre-application, until $37,000 to $50,000 is spent on an Impact Study, market signals are not available and do not present themselves as market makers. Once the solar system is interconnected, there are four streets that now have three-phase power available in a residential area that have been upgraded to service the transition to electric vehicles (EV) as well as for heat pumps and/or geothermal pumps for the residential homes. If the solar project upgrades the circuit protection at the substation, it will now likely provide bidirectional flow of electricity from EV and provide capacity for homes to upgrade to heat pumps for the entire circuit. Who are the beneficiaries now?

Should public policy make residential and small business properties reimburse the solar developer their prorate share of the circuit improvements? No. Expeditious electrification of the transportation and building sector should take precedence. Should they pay an application fee to pay for the cost of the EDC recording the load and application? Yes, a de minimis fee. Should the residential ratepayer pay for a truck roll to change out the feeder to the street? Probably not.

Looking at the DG Hosting Capacity map alone, how many street conductors are going to need to be replaced to accommodate each house lot with an average of two (2) electric vehicles and a house heated and cooled by electricity? How will a large presence of solar + storage + VAR support help the local area grid system?

As each home in that DG Hosting Capacity map over the next 20 years adds a heat pump, that motor will cause a phase shift in power during its operation, generating the need for VAR (Volt-ampere Reactive) or reactive power support. Today's solar inverters, such as those made in Lawrence, Massachusetts, by Yaskawa Solectria, have the capacity to make 125 kW/150 kVA inverters with 25 kVA in reactive power support or 150 kW/166 kVa inverters with 16 kVA in reactive power support.

When inverters are in VAR support, they are not generating solar energy so as indicated by an EDC engineer in the last TSRG meeting on December 8, 2020, compensating solar generators for VAR support has value.

Concurrently occurring interconnection of renewable generation, electrification of the transportation and building sectors including storage in various forms in all sectors creates beneficiaries of ratepayers.

Using the beneficiary-pays principle at the distribution-system level acknowledges that ratepayers within the same EDCs are implicitly or explicitly paying for most interconnection costs through supply costs or state incentives. This fact demonstrates that while the distribution system may not be networked, the costs are shared by all EDC customers. Because costs are shared, a more equitable and efficient cost allocation principle will benefit all ratepayers.[6] (B-1 at 7)

We agree with the AGO report by Strategen Consulting (B-1 at 4) that recognizes an "evolving policy landscape can necessitate new cost allocation considerations."[7] The FERC Order 1000, on transmission planning and cost allocation, similarly found that an evolving policy landscape can necessitate new cost allocation considerations.[8] The Commission also identified that the "risk of the free rider problems … is particularly high for projects that … may have multiple beneficiaries."[9] Not only does the Cost Causation Principle create inequity between DER developers through the free rider problem, but developers' attempts to avoid the free rider problem also inhibit the achievement of policy goals. Developers may delay their projects or defect out of the interconnection queue in hopes that another developer will pay the system modification cost instead. In Massachusetts, this delay can slow the progress of clean energy distributed generation, hinder state policy achievement,[10] and increase the administrative burden of queue management. FERC similarly acknowledged the consequence of slow facility investment"[11]

We agree with AGO's report on Differentiation (B-1 at 7) that different type and size projects may provide different grid and policy benefits and therefore should be treated differently. For example, this may lead to solar or DG projects under 25 kW having a flat fee or less costly interconnection cost. Behind the meter, commercial projects less than one (1 MW) megawatt would have a less costly per watt AC interconnection cost than a one to five (1-5 MW) megawatt project. In all instances, there would be a defined not-to-exceed cost of DG interconnection to the grid, including cost relating to transmission.

[6] Strategen Consulting, February 28, 2020 Prepared For: Massachusetts Attorney General's Office
[7] Strategen Consulting, B-1 at 4 & 5

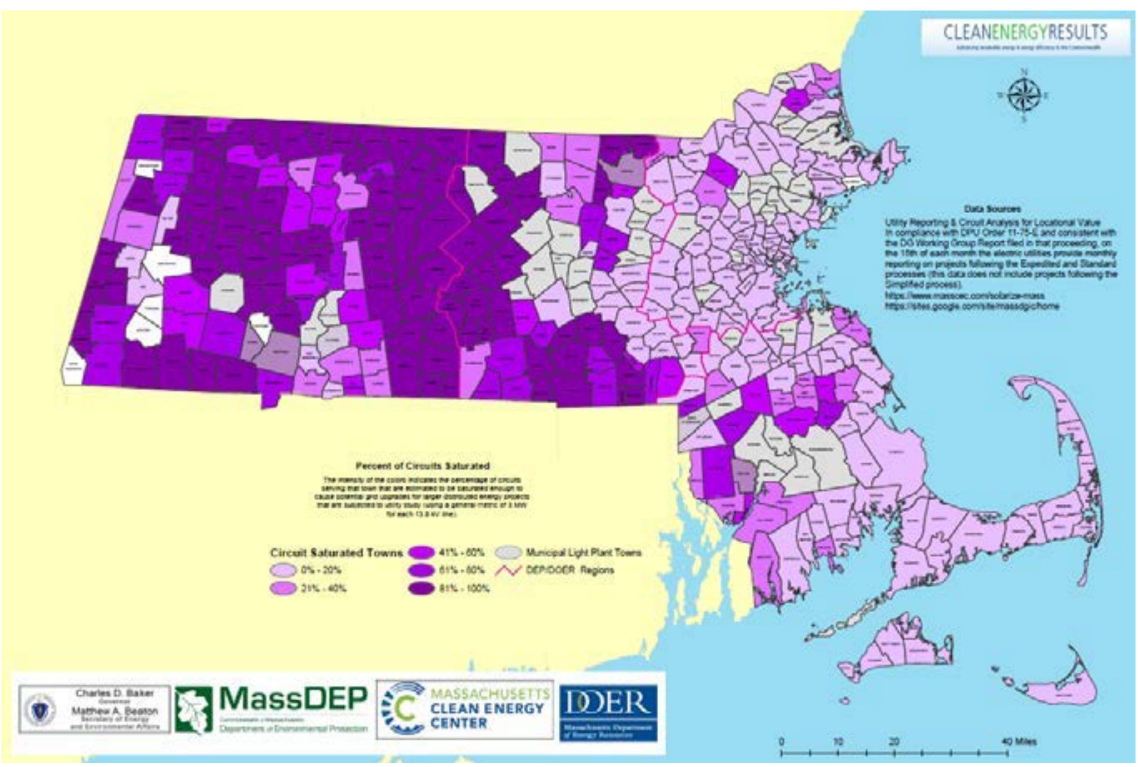
We agree with the AGO's report that curtailment is a means of mitigating large DG interconnection cost (B-1 at 11). It will be a necessary means of grid management in the future, but the curtailment costs need to be defined as a reduction of modeled revenue. Is the curtailment cost one half of one percent? Is it two and half (2.5%) percent of revenue? The SMART program is not a merchant power program. Any curtailment is a deduction from modeled revenue based upon industry standards. Within this curtailment discussion, as the larger transmission issues are addressed, rather than curtail, could renewable generation be exported to neighboring states who have unfulfilled emissions generation needs?

Public Policy and Price Signals on a Congested Grid

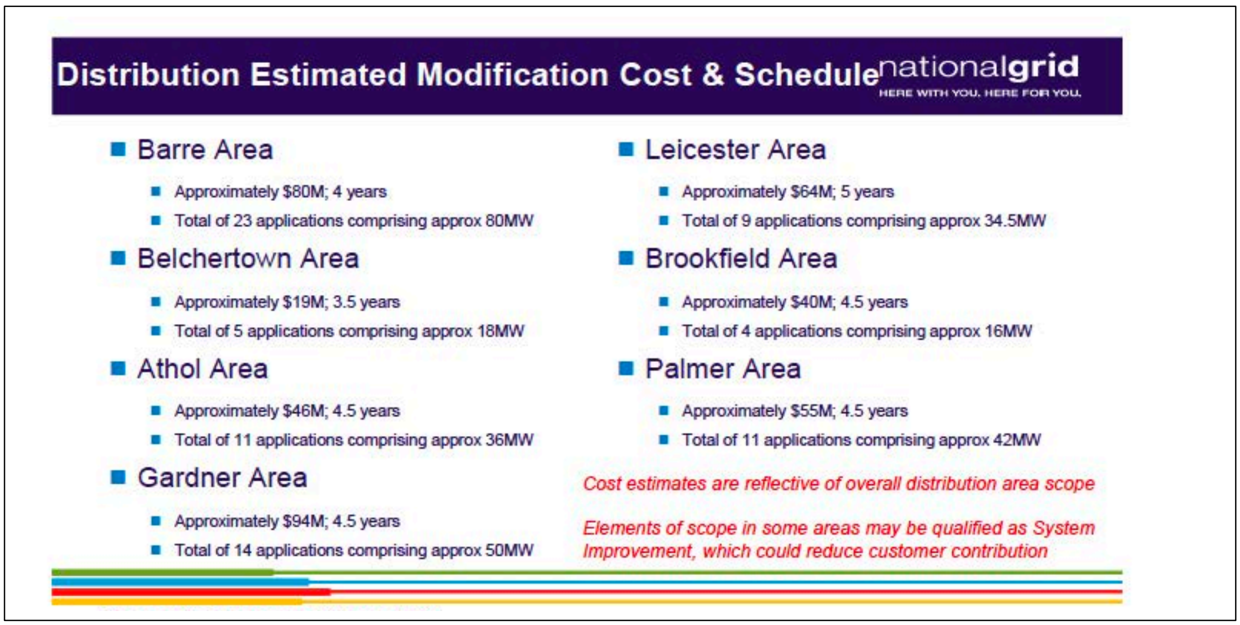
The map below was presented on December 13, 2019, by Commissioner Judith Judson discussing Massachusetts Distributed Energy Future at the Restructuring Roundtable run by Raab Associates. We have reason to believe that this map is even more congested at this writing.

Public policy states that siting of solar projects should respond to market-based price signals to affect the most efficient, least cost, and projects should be located closest to the consumption of electrical load. With a declining revenue SMART tariff, market price signals break down when $27,000 to $50,000 needs to be spent on an Impact Study that takes 5.5 months to 2 years to complete, there is no availability to interconnect, the financial cost is prohibitive, or a developer needs to wait 3-5 years to interconnect.

In Stat. 2016 c. 75 (11), the legislature directed DOER to “develop a statewide incentive program to encourage the continued development of solar renewable energy generating resources by residential, commercial, governmental and industrial electricity customers throughout the commonwealth.”



All stakeholder respondents to D.P.U. 19-55 used some version of the status quo in their approach to addressing the assignment of cost for the interconnection of DG. Below is the Distribution Estimated Modification Cost & Schedule which describes the cost of upgrading substations in congested areas. The average time for interconnection is 4.5 years. The improvements are based upon completed applications. The CUPZ program (B-4 at 3) is “incremental” and based upon completed applications. If significant, transformative changes are not made, Massachusetts efforts to ramp up renewables to meet GWSA targets, the solar industry, other DG technologies and in fact the wind industry will be not further ahead in five or ten years than we are right now.



If additional applications are made to the areas serviced by these substations, the applications will fall to the back of the interconnection queue. What will be their schedule for interconnection? Six years? Eight years? This condition does not represent the intent of Stat. 2016 c. 75 (11) “to encourage the continued development of solar renewable energy generating resources by residential, commercial, governmental and industrial electricity customers throughout the Commonwealth.”

This is why the Department needs to instruct the EDCs to prepare, through a tariff, for the annual installation of 1 GW of solar and wind generation. In so doing, the Department will set the global 30-year decision that will drive all other decisions in grid modernization, DG management, building and transportation sector integration and ensuing market development.

Pope Energy

How to Pay for These 30 to 50-Year Grid Modernization Infrastructure Upgrades

In B-4, Page 16, C., the Company describes a $100 million dollar investment costing the ratepayers $12 million to $14 million per year in reconciled cost. This amounts to a 7.1 to 8.3-year amortization of cost. A similar situation exists in D.P.U 18-150 Performance-Based Ratemaking Proposal, September 30, 2019, in one of the filings by the AGO, a weighted average depreciation rate for general asset is 10.198% per year.

[8]

Weighted Average Depreciation Rate for General Assets, 1996

	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)

That is the equivalent of asking ratepayers that own homes to finance those 30 to 50-year assets over 7 to 10 years. The only way to conduct resource planning and grid modernization is to have long-term assets be amortized separately based upon useful life.

See Line 7 above [Structure and Improvements]. These are the substations, street conductors, poles, towers, transformers, switchgear and the cost of labor and material to install the same.
Examples:
(FERC) Account 356 (Overhead Conductors and Devices) – 55-year service life
Account 362 (Station Equipment) – 45-year service life, Account 364 (Poles, Towers, and Fixtures) – 45-year service life, Account 366 (Underground Conduit) service life of 50 years.[9]

[8] 4-30-2019 Filer: Attorney General, WP-EconomicDepreciationRatesPowerDX(PEG)assuming33 vs 36, General. xls (tab)
[9] D.P.U. 18-150, Pages 295-302

In order to be able to afford the transformative grid modernization required to meet the GWSA obligations, long-term assets need to be billed to ratepayers over the term of the useful service life of the equipment separately and not billed in a weighted-average fashion or socialized with other utility capital expenses. At a minimum, a future rate case would only allow the billing and depreciation of long-term, grid-modernization assets on the schedule of their useful life.

We are not familiar with the cost of capital of a privately held, publicly traded EDC and what rates of return are expected on internal or borrowed funds. We surmise that the cost of capital is between something greater than the dividend rate to stockholders and equal to the return on assets allowed in the tariff. Those interest rates are greater than tax-exempt rates that could be financed through Mass Development.

{For the record, we have had correspondence with Mass Development, and due to the premature nature of this idea, they are in no position to make comment whatsoever. 12-21-2020}

The “public good” financed by Mass Development would be to support lowering the cost for ratepayers to modernize the electric grid to lower emissions from 1990 levels in compliance with the Global Warming Solutions Act and related laws that requires Massachusetts to have 85% net-zero emissions by 2050.

A rate case would be litigated, a Grid Modernization tariff approved that separated long life span assets for longer recovery/depreciation periods that match the actual service life of the asset. The EDC would complete the work with its own funds and, once complete, the EDC would have the debt funded for that portion of completed work on a tax-exempt basis with Mass Development. The structure of the Mass Development loan would be recognized within the rate case and repayment of the loan would be guaranteed through the sale of delivered electricity to ratepayers.

If there are legal barriers, Mass Development borrower entity size limits, SEC or EDC stockholder objections to long-term obligations, then a finance “Facility” could be set up to hold the assets and liabilities and to receive repayment funds for the loan.

The Facility would be a non-profit entity either independently held or held by the EDCs, AGO, DPU, DOER the Secretary of EEA. The purpose of the Facility would be as a financial conduit to hold debt at tax-exempt rates from Mass Development to finance grid modernization assets with a service life of over 30 years. The repayment stream of revenue would be secured by access to a tariff delivering electrical service to ratepayers.

The EDCs under a grid modernization tariff would build out the transmission and distribution grid network to receive the installed capacity 1 GW of solar and wind per year. Upon completion of the work and “acceptance” by D.P.U., the EDCs could then invoice, recover and access the long-term Structure and Improvements portion of the cost from the Facility. Title to the assets pass to the Facility as collateral against debt. In arrears, on a periodic basis (bi-annually?) to be approved in the rate case, the EDCs could invoice for the current portion of Structure and Improvements portion of the work and recover such cost from ratepayers. The payments received from ratepayer is essentially a pass-through to the Facility to pay off the debt to Mass Development.

The Facility has no performance obligations other than to process and pay off debt. In order to receive the Return on Investment allowed by tariff, the EDCs are contractually obligated to warranty, maintain, replace, insure all of the Structure and Improvements assets without exception. With each periodic payment of debt to the Facility, the current portion of the assets and all of the residual value, returns to the EDC balance sheet.

This concept aligns with the beneficiary pays model as the beneficiaries (the ratepayer) are being billed for cost of the Structure and Improvement assets over the service life of the asset.[10]

[10] Strategen Consulting, February 28, 2020 Prepared For: Massachusetts Attorney General’s Office, B-1 at 6

a. ***The Department has identified the following list as solutions that address potential system needs.***
   i. Technologies for Voltage Control on the Distribution System.
   Answer: VAR (Volt-amperes Reactive), Smart Inverters.
   ii and iii:
   Answer: Bulk transmission and distribution equipment should be planned to accommodate the installed capacity 1 GW of solar and wind per year.

b. ***Should transmission studies and cost be included in proactive system planning as it relates to interconnection?***
   Answer: As described in Pages 7, 8 and 9 of this submission, the electrification of the building and transportation sector and powering those resource with renewable energy is too integrated to single out a first and prime movers such as solar, storage or soon to be EV's and heat pumps.

c. ***Should the distribution system assessment identify projects that provide broader benefits beyond enabling the incremental DG Capacity?***
   i. What benefits should be considered?
   Answer: The concurrent development of renewable DG, and the electrification of the building and transportation sectors.
   ii. How should these benefits be quantified?
   Answer: Looking at the DG Capacity Map on Page 7, the Department and EEA should have an expectation that X percentage of households will have EVs and heat pumps in 5,10,15 and 20 years. Since the average rule of thumb for EV consumption is 3 miles per kWh[11], an EV traveling 12,000 miles will use 4,000 kWh per year and an EV traveling 12,000 miles will use 4,000 kWh per year. Two EVs in each household traveling 12,000 miles each per year will require 8,000 kWh in electrical supply per year. Level 2 EV chargers are 240v, 30-50 amps. How will renewable energy be delivered to a neighborhood of households and how will the grid systems in place enable the bidirectional flow of electricity to

[11] https://forums.tesla.com/discussion/82228/average-kwh-per-year-for-12-000-miles-per-year

meet policy goals? The decisions made in D.P.U. 20-75 will enable policy execution in the fast-approaching future. See following page for average car and driving patten charts.

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

Answer: Because the policy objectives to install renewable generation and electrify the transportation and building sectors happen concurrently, a free-ridership condition exist prejudiced against first applicants for interconnection.
We recommend an either a flat fee or actual cost of interconnection if less than the capped, not to exceed cost of $0.15 to $0.20 per watt AC plus the project specific Point of Common Coupling cost.
We propose using the work Sustainable Energy Advantage developed in their engagement with DOER in the early stage of the SMART program shown below.

Cost_Data_Entry_040416, Sustainable Energy Advantage as part of a consulting engagement with DOER.

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

Background-Key Terms | Instructions | Your Contact Information | Capital Costs | Interconnection Costs | Ongoing O&M Costs | Inverter Costs | Financing | 3rd Party v Host Owned

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

a. Simplied Facilities: i,ii, & iii

Answer: We believe that interconnection is a real property entitlement asset and that all interconnection parties should pay a fee to interconnect. At $0.20 per watt AC the cost for a 5 kW system would be $1,000, at $0.10 ($500) and at $0.05, ($250), at $0.03, ($150). While an argument could be made that a transformer cost $45,000 or more and that these DG systems should bear such cost, we return to our assertion that the electrification of the building and transportation sectors will require much more support; in fact, the widespread use of residential solar + storage + smart inverters providing VAR support should be encouraged and ultimately, may yield tremendous grid support benefits. Our recommendation would be a flat fee of $150 for small projects under 10kW and $300 for those projects 10kW to 25kW.

Projects 25kW to 60 kW would pay a flat fee of $0.10 per watt AC.
Projects greater than 60 kW to 500 kW would pay $0.15 per watt AC.

b. Expedited and Standard Facilities

i. Is a minimum Common System Modification Fee appropriate?

Answer:

1. The Department could set a minimum fee of ten ($0.10) cents for projects over 500 kW. This is a starting point to differentiate between project types to target certain sectors that interconnection policy wants to encourage. The ten ($0.10) cent level is also consistent with the SEA Cost_Data_Entry_040416 chart completed on behalf of DOER.

2. The minimum fee is an attempt to strike a balance between policy prerogatives. A minimum fee of $0.10 could be for one set of projects say rooftop, less than 500 kW and another set of projects could be $0.10 per watt AC plus the cost of transformers with another set of projects have a minimum charge of $0.10 plus the cost of transformers and Point of Common Coupling cost. Larger projects could start out with the minimum

interconnection fee of $0.10 per watt AC plus Point of Common Coupling plus a larger system surcharge of $0.05 to $0.10 per watt AC.

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

Answer:

Grid system congestion does not allow market signals to be sent at all. If every Pre-application is returned that has 2440 kW of DG on a 10-12,000 kW circuit (with 7,560-9,560 kW in capacity) and comes back with the notation below, there are no market signals.

"A system impact study will be required for a 5,000-kW solar array at the requested point of interconnection. Islanding, reverse flow, flicker, high voltage under light load and interaction with step downs and OH PTR on the circuit would need to be looked at. A 5,000 kW solar farm interconnection could very well require additional extensive review including possibly transmission-level thermal and stability analysis. An installation of the proposed scale would require remote telemetry and revenue grade data acquisition."

Given the primary responsibility of the EDC is to maintain system reliability, the above-mentioned conditions are prudent. To expect market conditions on an existing system that is already overburdened, plus SMART capacity, plus 2030 DG interconnected goals to think market conditions exist is aspirational at best.

In order to make payment for an Interconnect Application fee of $7,500 plus an Impact Study fee of $37,000 - $50,000, the DG developer must have land control which has its own expense of project origination and legal expense. In addition, the developer must engage a licensed engineer to prepare drawings for submittal to the utility. Now a ratepayer landowner, farmer, business owner or corporation and solar developer has expectations that the laws and regulations to encourage renewable energy generation that are in place are going to produce a productive outcome.

The only way market signals are able to have an effect on the siting of DG, is to have a pre-application processed in two weeks actually mean something; a definitive Yes or No on an increasing number of circuits on all sizes of projects before the landowner/farmer/corporation ratepayer and developer become invested in the process in time, expense and expectations. If the number of circuits available are in decline or are 3.5 to 5 years out before interconnection, the market signal disappears.

The real market signals have been sent by the legislature in the Global Warming Solutions Act (St.2008, c.298); Act Relative to Solar Energy (St. 2016, c. 75); Renewable Portfolio Standard (G.L. c.25A, & 11F; 225: C.M.R. 14.00, et seq.); Net Energy Metering (G.L. c. 164, & 138-140); Clean Energy Standard (310 C.M.R. 7.75); Clean Peak Standard (G.L. c. 25A, & 17 (a);225 C.M.R. 21.00, et seq.)[12].

The D.P.U. 20-75 straw proposal only expands considerations on the status quo; it does not ask the EDCs for solutions to meet the intent of the legislature because it has not set annual renewable energy installation targets.

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

Answer: Fees would be paid to the EDCs, reconciled against total circuit, substation and transmission upgrades cost. All other upgrade costs would be rate based under a tariff that amortizes long-term cost against the equipment's useful service life.

ii Is a fixed Common System Modification Fee appropriate? If so,

1. **Provide a proposed method for establishing such a fee.**

Answer: Given that market signals do not effectively exist due to the aforementioned complexity and that interconnection is an income-producing real estate entitlement asset that, in our belief, all interconnected DG parties should contribute to the interconnected grid cost in some fashion, we believe the Fixed Fee for Interconnection is the best method to implement employ. The Fixed Fee is simple to implement immediately, its method of establishment is transparent, it requires little management, administration and education of and by the Department, the EDCs, developers and the consuming public.

[12] Strategen Consulting, February 28, 2020 Prepared For: Massachusetts Attorney General's Office, B-1 at 5

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

Answer: Interconnecting energy storage, electric vehicles, upgrading to heat pumps, and distributed energy resources like solar are all economic models. If the cost is too high or revenue too low, then the public policy objectives set forth by the legislature will not be implemented.

The Cost_Data_Entry_040416 by SEA on Page 17 engaged on behalf of DOER, observes experienced interconnection cost by solar developers. Those costs were used in some fashion by DOER in modeling compensation for the SMART program that had a cap of $0.17 per kWh.

Solar developers and all DG, transportation and building sector participants interconnecting to a renewable grid need both time and price certainty to efficiently execute public policy.

We contacted small residential solar installers, commercial 60 kW – 500 kW solar installers, and used our own experience and that of other solar developers in larger solar projects to inform our proposal in D.P.U 19-55. The small residential solar installers had tremendous difficulty in securing work due to the last ratepayer in the neighborhood was now required to bear all of the upgrade cost of a congested transformer or circuit. The commercial 60 kW – 500 kW solar installer suffered from uncertain interconnection cost, long interconnection lead times, long post mechanical completion connections and interconnection cost over $0.20 per watt AC.

Larger projects have experienced the full gamut of difficulties from long periods of times to receive and ISA, to ISA taking years in queue positions just to get the Impact Study process started, to ASO study delays to post mechanical completion delays in interconnection. Our lowest ISA cost was $0.10 per watt AC including Point of Common Coupling Cost and our highest ISA cost as $0.41 per watt AC including PPC cost and had some cost shared with another project on the same circuit. At time of Pre-application and commencement of the Impact Study we had no certain visibility as to the certainty of cost. With the $0.10 per watt AC ISA, we just got lucky. The $0.41 per watt AC could only be financed because the site work cost was so low on this project. Solar developers of all sizes need dependability of cost and time. A Flat Fee for interconnection provides that clear path for project viability.

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

Answer: A Fixed Fee by its very nature establishes clear cost signals and provides cost certainty. More importantly, all solar developers, energy storage, electric vehicle, and other DG developers and installers can represent to their customers, farmers, landowners, corporate customers, non-profits and cities and towns that the proforma estimate is accurate within definable exceptions.

On more than one occasion, we have had the "big" meeting with a well-known corporate entity only to have to qualify our presentation by saying we are unable to accurately project the viability of the project because at the time of presentation we did not know when the next solar program would be promulgated, how much the interconnection cost would be, how long the interconnection process would be or what Block the project would be assigned. If the Department desires to meet a specific installation rate of any kind of renewable technology, the process must be simplified.

Limiting Ratepayer Cost: Integral to the success of becoming 85% net-zero emissions by 2050 is the involvement and participation of every ratepayer in the Commonwealth in the transition to renewable technologies. Whether it is the farmer receiving land rent, the fisherman lowering his/her refrigeration cost, building owners renting roof space for solar, EV owners no longer having internal combustion repairs, oil and fuel bills, homeowners no longer having commodity fluctuations in fuel pricing and burner repairs, or real estate owners not having to clean and replace assets due to lack of soot and pollutants, the sooner the Department creates the conditions for more expeditious installation of renewable, the lower the cost will be for ratepayers. Huge corporations with large physical plants and massive BTU requirements also have huge human resource investments in personnel. If the health and welfare of their employees are better, attracting and retaining valuable talent also increases competitive value to their corporations. The cost of electricity will go up, but to realize ratepayer value, the Department needs to enable the transition to renewables by removing the thermal load impediment to the transmission system and the voltage control at the substation levels.

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

Answer: Fees would be paid to the EDCs, reconciled against total circuit, substation and transmission upgrades cost. All other upgrade costs would be rate based under a tariff that amortizes long-term cost against the equipment's useful service life.

1. **As part of your explanation indicate whether a maximum price for Common System Modification Fees is appropriate.**
   Answer: Recognizing product differentiation, the maximum fee for residential, small commercial, 60 kW - 500 kW or 1 MW may be different from larger up to 5 MW systems. But in no instances should the maximum fee exceed $0.20 per watt AC.

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

Answer: The Cost_Data_Entry_040416 by SEA on Page 17 engaged on behalf of DOER, observes experienced interconnection cost by solar developers. Those costs were used in some fashion by DOER in modeling compensation for the SMART program that had a cap of $0.17 per kWh.

All interconnections of renewable DG technologies including solar are economic models. Typical solar project development cost with SMART revenue mirroring basic service rates, $0.20 per watt AC is the maximum a project can afford. Even at those rates, adders are required to make a project financially viable.

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

Answer: Nameplate.

Export capacity will depend upon the deployment of technology, innovation and capital. Do not discourage innovation as it will benefit the ratepayer. Keep it simple, less is often better.

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

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

Answer: Reconciled cost roll up in the same account(s) as the locationally based upgraded feeder, substation component, or transmission upgrade. If the Flat Fee, Minimum Fee or Maximum Fee pays for all of the upgraded cost, then there should be a record of such occurrence.

The ratepayer pays for everything either through a SMART, Clean Peak, D.P.U. 20-75 or Grid Mod tariff. The concept that a dedication of funds should be apportioned for a specific purpose when 85% net-zero emissions by 2050 are before the ratepayer is a superfluous exercise.

It is important to note that interconnection upgrades paid by developers in the SMART tariff are paid using (illustratively) 60% LTV, 15 to 20-year debt at 5.25% interest, with investors IRR at 9.5%[13] as opposed to the tax-exempt rates previously proposed.

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

Answer: Yes.

(3) Refer to Vote and Order, Section III, Proposals For Implementation in the Short Term. Please discuss the effectiveness of these proposals, specifically:

a. Attorney General's Power Control Limiting Program (Att. B-1, Att.)

Comment: We believe the AGO Power Control Limiting Program is viable, if economic curtailments are modeled within certain financial parameters. The SMART program is not a merchant generation program with merchant risk. Curtailment beyond certain economic limits would add uncertainty to finance modeling. Incidental frequency or over voltage curtailments

[13] Rhode Island REG Program, 2021 Ceiling Price Recommendations to DG Board, Sustainable Energy Advantage October 26, 2020 Page 26

would not add uncertainty but shoulder season curtailments for hours at a time for six months would definitely add uncertainty which would affect project financing, severely affecting project viability. If curtailments were limited to say 0.005%, 1% or 2.5% of total revenue, those limits would be modeled as a reduction in project revenue for 20 years, which is the length of the SMART program.

i. **Would eligibility for the Program be for (a) New Interconnecting Customers or (b) new and existing Interconnecting Customers**?

Answer: (a) New only.

There might be an OPT in provision for existing systems, but to curtail revenue impacts the existing executed ISA, SMART SOQ and financing for operational systems that have already paid the ISA upgrade fees. We agree that there are existing inequities in the system where the first interconnected project "responding to market signals" may achieve a lower ISA cost, but it is more important for Massachusetts not to contractually change the rules on executed obligations and commitments.

ii Identify equipment and software necessary for implementation of the (Curtailment) Program and which equipment and software would be installed (a) at the Interconnecting Customer and (b) at the Distribution Company.

Answer: When we requested technical assistance from our solar engineers, the P.E. responded in the following fashion.

"Without any additional information about this curtailment process, I can only speak in generalities. Yes, the technology exists to have inverters curtailed (rather than a recloser simply turning a PV system on or off) but it is not currently an industry standard scheme.

Most inverters do have the ability to accept MODBUS communication from an external custom RTAC programmed to interface between the inverter and an external SCADA system. This RTAC will have the ability to write a particular value to the inverter's MODBUS registers as dictated by the external system, perhaps as mandated by the utility, telling the inverters to produce a set amount of power."

Our translation: Yes, the technology exists, but it is going to take some work to create a working standard that meets the technical requirements of the EDC's, the policy objectives of the Department and the economic concerns of developers. The TSRG would be a good place to start to work out these details.

iii Identify any amendments or attachments to the ISA that would be necessary to implement the Program.

Answer: The ISA would have to refer to a D.P.U tariff, describe curtailment for transparency purposes

We appreciate the Department taking the time to review our comments.

Best Regards,

Doug Pope
President

Exhibit 1

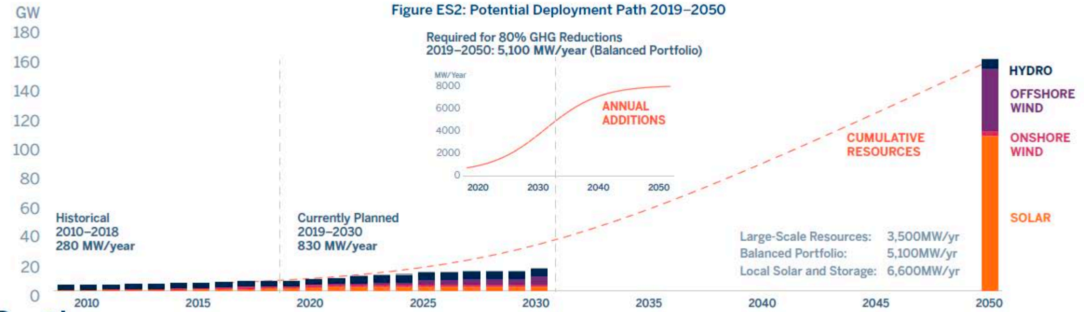
Brattle Group, Achieving 80% GHG Reduction in New England by 2050, September 2019

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

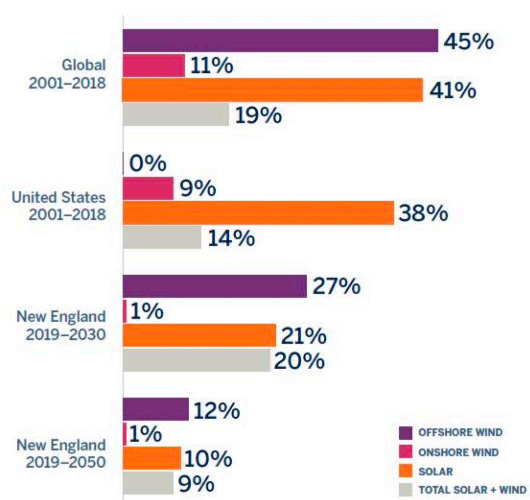
Figure ES2: Potential Deployment Path 2019–2050



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



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