

Electric Power Sector

INTRODUCTION

New England's power system and wholesale electricity markets are highly complex systems that require coordination between power production and delivery for the purpose of supplying power to Connecticut customers. Frequently referred to as the electric grid, the electric power system is comprised of three key elements: generation, transmission, and distribution. In addition, sophisticated information systems monitor and coordinate electricity production and delivery. This regional system includes approximately 350 generators, 31,000 megawatts of generation capacity, 600 megawatts of demand response, and 1,700 megawatts of energy efficiency.¹ The regional transmission system includes 8,600 miles of high-voltage transmission lines, and 13 transmission ties to neighboring power systems (New York and Canada). Much has changed in the region's electric system since electric restructuring in the late 1990's-2000, as market fundamentals and state public policies have shifted. The regional market includes three markets: (1) Energy: daily market for electricity, (2) Capacity: annual forward auction for long-term resource availability, with an obligation for one year or seven years for new resources, and (3) Ancillary services: daily market for real-time reliability services.²

Historically, the power grid represented one directional power flow from a central station power plant to consumers. Across New England and in Connecticut, state policies are promoting renewable resource development – both grid-connected and smaller-scale “behind the meter” installations – that collectively are creating a “hybrid-grid” that integrates both central station and distributed generation. Additionally, the shift from coal and oil to natural gas and clean energy resources has reduced greenhouse gas (GHG) emissions from the electric supply sector over the past 15 years. The transformation already underway provides some perspective on what the grid of the future might look like. This chapter begins to articulate Connecticut's future vision of the evolving grid.

Connecticut's grid of the future must achieve the broad goals of delivering cheaper, cleaner and more reliable electricity. It will need to integrate both central station and distributed generation, and incorporate technologies such as energy storage and demand response. The system will need to continue to support system resiliency and enable additional deployment and interconnection of microgrid systems. Increased deployment of technologies such as energy storage will usher in increased levels of flexibility to grid operations and encourage cost savings, especially during

¹ State of the Grid: 2016, ISO-NE, January 26, 2016.

² *Ibid.*

times of peak electrical demand. A secure network and an information backbone that is resilient to cyber assaults must support the grid of the future. It will need to enable a seamless integration of a variety of resources, connect with advanced technologies that are flexible in nature, and be capable of achieving increased reliability and customer response. In the near future, there will be an increasing demand for electricity to replace fossil fuel energy for transportation and buildings in order to meet the need for steep reductions in economy-wide greenhouse gas (GHG) emissions. Achieving this vision of the grid of the future will be challenging, and will require additional planning, deployment and changes to both institutional and regulatory frameworks.

Several drivers are likely to change the dominant features of the power grid in the years ahead:

- Connecticut's Global Warming Solutions Act (GWSA) sets a goal of reducing greenhouse gas emissions by 80 percent below 2001 levels by 2050.
- Electric sales in the short to medium-term, will remain constant, or decrease.
- Renewables will gain steadily in their share of generation, and environmental standards will require power generation to become less carbon intensive.
- New distributed generation (DG) technologies will emerge, such as smart grids and "intelligent" demand side technologies with two-way communication that enable peak shaving or load shifting.

UPDATE ON 2013 CES RECOMMENDATIONS

The 2013 CES advanced ten key recommendations within the electricity sector. Many of these recommendations focused on the creation of new programs for renewables, innovative approaches to financing developed in partnership with the Connecticut Green Bank, and the advancement of reliability and resiliency efforts to harden and protect Connecticut’s critical energy infrastructure. Collectively, DEEP along with many key partners have made considerable progress in advancing these key energy policy initiatives. A summary of the State’s efforts are summarized below:

1. ENGAGE VIGOROUSLY IN REGIONAL AND FEDERAL REGULATORY PROCESSES	
Recommendation Summary: DEEP’s Bureau of Energy & Technology Policy should increase its engagement with other states and regional organizations to help shape policy at FERC and ISO-NE.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> DEEP has increased engagement with other states and regional organizations through regular meetings with ISO-NE, NESCOE, OCC, AGO, and PURA to shape the state’s energy policies within the regional context.
2. WORK WITH MUNICIPALITIES TO EXPAND PROGRAMS AND POLICIES THAT DRIVE DOWN THE COST OF IN-STATE RENEWABLE RESOURCES	
RECOMMENDATION SUMMARY The State should take steps to ensure that the average installed cost of solar PV falls below residential rates and streamline permitting, siting, and other requirements to help reduce the “soft costs” of solar PV installations.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> Data³ from the Green Bank demonstrates that the cost of rooftop solar has declined and the Green Bank has seen success with its Solarize Connecticut campaign.
3. EVALUATE OPTIONS FOR WASTE-TO-ENERGY IN CONNECTICUT	
RECOMMENDATION SUMMARY DEEP should monitor waste-to-energy facilities as long-term power purchase agreements end and operating costs increase.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> DEEP has monitored the state of waste-to-energy facilities. H.B. 7036 in the 2017 session increases the Class II RPS requirements to 4 percent and only qualifies waste-to-energy facilities permitted by DEEP as Class II.
4. EXPAND VIRTUAL NET METERING OPPORTUNITIES TO PROMOTE DEPLOYMENT OF LARGE-SCALE RENEWABLE SYSTEMS	
RECOMMENDATION SUMMARY The State should expand existing virtual net metering provisions to include agricultural hosts as well as government entities and lift the cap to \$10M.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> Virtual net metering has been expanded to include agricultural hosts and has seen active participation. The cap was increased to \$10M, then increased an additional \$6M for municipalities in 2016 and \$3M for agricultural in 2017.

³ Data can be found in the Appendix.

5. STRENGTHEN THE REGIONAL CARBON DIOXIDE CAP AS CALLED FOR BY THE RGGI PROGRAM REVIEW	
RECOMMENDATION SUMMARY Connecticut should implement changes in RGGI Program Review and lower the regional carbon dioxide cap to ensure RGGI continues to incentivize better environmental outcomes.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> 2016 RGGI Program Review is still ongoing. Expectation is an extension of the annual cap decline.
6. DEVELOP SUB METERING PROTOCOLS TO PROMOTE THE USE OF RENEWABLE ENERGY AND COMBINED HEAT AND POWER IN MULTI-TENANT BUILDINGS	
RECOMMENDATION SUMMARY PURA should establish rules to enable submetering generally with appropriate consumer protections.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> PURA has established standards for submetering at multi-tenant buildings using renewable energy.
7. DEVELOP AND DEPLOY MICROGRIDS TO SUPPORT CRITICAL SERVICES AND ENSURE PUBLIC SAFETY DURING ELECTRICITY OUTAGE CRISES	
RECOMMENDATION SUMMARY DEEP should continue pursuing microgrid opportunities and work with the General Assembly to provide for flexibility in the program.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> DEEP developed a microgrid program will result in the deployment of up to 20 microgrids. Five microgrids are operational and five are in the development stage. The program is open to new applications and DEEP is now authorized to fund clean distributed generation and energy storage in its microgrid grant program.
8. IMPLEMENT THE RELIABILITY RECOMMENDATIONS OF THE TWO STORM PANEL	
RECOMMENDATION SUMMARY The State should implement the reliability recommendation of the Two Storm Panel relevant to DEEP, PURA, the Department of Transportation, the Siting Council, and other agencies.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> Many of the vegetation management recommendations of the Two Storm Panel have been implemented.
9. CHARGE PURA WITH CYBER SECURITY REVIEW OF STATE’S PUBLIC UTILITIES AND WATER COMPANIES	
RECOMMENDATION SUMMARY PURA should work with other relevant state agencies to review the state’s electric, gas, and water company abilities to deter interruption of service.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> PURA held a series of collaborative meetings on cybersecurity and established a cybersecurity oversight program
10. TRANSITION CURRENT STANDARD SERVICE CUSTOMERS TO THE COMPETITIVE SUPPLIER MARKETPLACE	
RECOMMENDATION SUMMARY DEEP and PURA should make tranches with the remaining standard service customers to make them available in the competitive supplier market.	KEY ACHIEVEMENTS <ul style="list-style-type: none"> The idea of dividing standard service customers into tranches for competitive electric suppliers was not supported by the General Assembly and thus did not go forward.

Current State

The Independent System Operator, ISO New England, Inc. (ISO-NE), operates the region's electric power system, administers the region's competitive wholesale markets and oversees the planning process for the regional power system. The Federal Energy Regulatory Commission, or FERC, is an independent federal agency that regulates the interstate transmission of electricity and natural gas. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects. The Connecticut Public Utilities Regulatory Authority (PURA) regulates the electric distribution system in Connecticut.

Shifting Towards Natural Gas as the Primary Fuel for Electric Generation

The most pronounced change in the regional electric power system since electric restructuring occurred has been a shift in the fuel mix, or the type of fuels used to generate electricity in New England. Over the last fifteen years, natural gas has replaced coal and oil as the dominant fuel source in New England. After deregulation, merchant investment in new, highly efficient combined cycle gas generation increased significantly.

The use of natural gas to generate electricity in the New England region has grown from 15 percent in 2000 to 49 percent today. At the same time, oil and coal have declined from 22 percent and 18 percent in 2000 to 2 percent and 4 percent respectively in 2016. In addition, nuclear power has been an important contributor to electric generation and has remained relatively constant at approximately 30 percent.⁴

Ensuring resource adequacy and reliability, the intent of the ISO-NE forward capacity market is to encourage the development of new resources to meet the demand for electricity in New England. However, 80 percent of new capacity since 1997 runs on natural gas and nearly 65 percent of all proposed new generation will use natural gas.

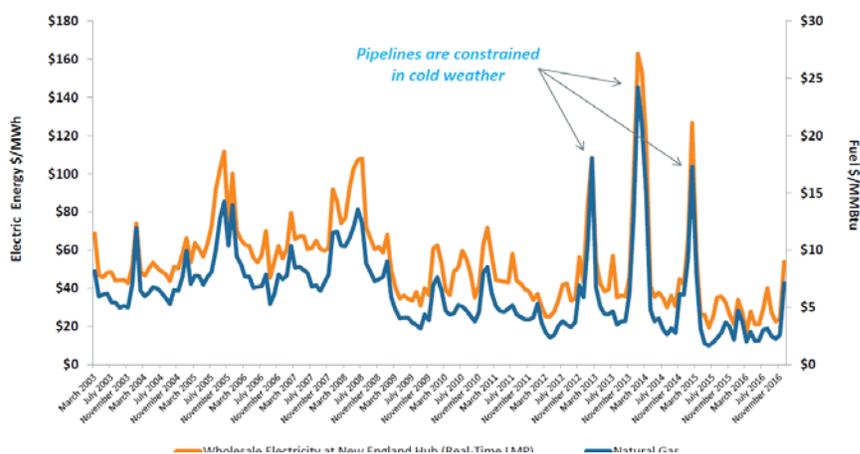
The demand for natural gas is rising, yet gas pipelines are constrained during high demand periods, particularly during the winter months. These conditions create grid reliability concerns and price volatility during cold winter months. Renewable generation represents a small but growing amount of new generation.⁵

⁴ The December 2014 retirement of the 600, MW Vermont Yankee Plant reduced nuclear generation's share from 34 percent to 30 percent.

⁵ See ISO-NE Presentation dated January 30, 2017, State of the Grid: 2017, ISO on Background, slide 9, *available at* https://www.iso-ne.com/static-assets/documents/2017/01/20170130_stateofgrid2017_presentation_pr.pdf

As shown in Figure E1, wholesale electricity prices in New England are closely correlated with the price of delivered natural gas. Natural gas units are now so predominant that bids into the ISO-NE energy market set the wholesale energy price in approximately 75 percent of the hours of the day.⁶

FIGURE E1: Monthly Average Natural Gas and Wholesale Electricity Prices in New England



Source: ISO-New England Regional Electricity Outlook, 2017

Low energy prices driven by low gas prices and the addition of more renewable generation is putting financial pressure on coal, oil, biomass, refuse and nuclear base load generators. Due to age and declining revenues, some generators have already retired and others may find it necessary to retire in the future. Over 5,000 MW of additional oil and coal capacity are at risk for retirement in coming years, and uncertainty surrounds the future of 3,300 MW at the region's remaining nuclear plants.⁷ The older units are less flexible than the newer natural gas units, taking up to 24 hours to reach their full production capabilities, making them less appealing to the ISO for dispatch. This combination of factors has led to the retirement of several generating units including Norwalk, Bridgeport Unit 2, Mount Tom and Salem Harbor and most recently, Brayton Point. The last remaining coal unit in Connecticut, Bridgeport Unit 3, is expected to retire in 2021.⁸ In addition to the retired coal and oil units, several of the nuclear power plants in ISO-NE have closed (Vermont Yankee in 2015) or are closing soon (Pilgrim in 2019).

⁶ Wholesale energy prices are set by the marginal cost of the most expensive resource needed to supply the demand. This cost is calculated every five minutes. 2015 ISO-NE Electric Generator Air Emissions Report.

⁷ ISO-NE, Regional Electricity Outlook, Retirements of Non-Gas-Fired Power Plants.

⁸ Whether Bridgeport Unit 3 retires in 2021 will be determined in FCA 12, which will take place in February 2018.

Cleaner Generation Fleet is Yielding Environmental Benefits

Natural gas-fired power plants have largely displaced older coal- and oil-fired facilities in terms of electricity production. This shift to a cleaner fuel mix has resulted in a decline of pollutants such as CO₂, NO_x and SO₂. According to ISO-NE's 2016 Air Emissions report, between 2001 and 2014, CO₂ emissions from generation in New England dropped by 26 percent, NO_x declined by 66 percent and SO₂ declined by 94 percent. However, in 2015 following the retirement of the Vermont Yankee nuclear plant, New England saw a rise in CO₂ emissions of 2.5 percent over 2014 emissions.⁹

TABLE E1A: Reductions in Aggregate Emissions (ktons/year)

Year	NO _x	SO ₂	CO ₂
2001	59.73	200.01	52,991
2014	20.49	11.68	39,317
% Reduction, 1999-2014	-66%	-95%	-26%

TABLE E1B: Reductions in Average Emission Rates (lb/MWh)

Year	NO _x	SO ₂	CO ₂
1999	1.36	4.52	1,009
2014	.38	11.68	39,317
% Reduction, 1999-2014	-72%	-95%	-28%

Source: 2014 ISO-NE Electric Generator Air Emissions Report, January 2016

Connecticut is a leader in taking steps to reduce the greenhouse gas emissions related to electric generation. In 2008, Connecticut became one of nine states to implement the Regional Greenhouse Gas Initiative (RGGI), the first mandatory carbon dioxide cap and trade program in the United States. In addition, Connecticut's 2008 Global Warming Solutions Act (GWSA) sets a goal of reducing greenhouse gas emissions by 80 percent below 2001 levels by 2050.¹⁰ While seeking to develop the renewable energy market and reduce the negative environmental impacts of traditional electric generation, the State has also set very aggressive targets for deploying renewable generation. Connecticut's Renewable Portfolio Standard (RPS) requires that 20 percent of generation serving state customers be from Class I renewable energy sources by 2020.¹¹

⁹ 2015 ISO-NE Electric Generator Air Emissions Report.

¹⁰ Conn. Gen. Stat. § 22a-200a.

¹¹ Conn. Gen. Stat. § 16-245a.

Renewable Generation Grows as Costs Decline

Renewable generation has increased significantly in New England over the past 10 years. Much of this increase is due to Renewable Portfolio Standard (RPS) requirements in Connecticut and in surrounding states. A considerable amount of the generation has come from out-of-state grid-connected projects such as wind and biomass, but there has been a large increase in smaller behind the meter fuel cell and rooftop solar projects over the past few years. Connecticut's net metering, virtual net metering and low-emission renewable energy credit (LREC) and zero-emission renewable energy credit (ZREC) incentives have spurred growth in these behind the meter projects. Connecticut has also increasingly used large-scale procurement to help new renewables come online in the region. Over the years, Connecticut has seen the cost of clean energy renewables decline.

Renewable Portfolio Standard

Following the 2013 CES, Public Act 13-303 and Public Act 15-107 provided Connecticut with broad statutory authority to procure grid scale clean energy. The combination of policies and procurement authority has supported additional deployment of renewables, both grid scale and behind the meter. Connecticut and other New England states have led the region with a suite of programs to substantially increase new renewable development in the region. The foundation for the state's renewable deployment efforts is the state's RPS, which was enacted as part of the state's electric restructuring legislation in 1998. As one of the State's primary policy mechanisms to encourage the development and continued operation of renewable generation in New England, an RPS creates a financial incentive for developers to develop renewable energy projects by requiring electricity suppliers to purchase set quantities of renewable energy over time. The RPS thereby guarantees a market and potential stream of revenue for renewable generators based on the type of resource and whether it qualifies as Class I, Class II, or Class III in the statute.

TABLE E2: Connecticut RPS Requirements, (percent of CT total electric use)

Year	Class I	Class II (or Class I additional)	Class III	Total
2013	10%	3%	4%	17%
2014	11%	3%	4%	18%
2015	12.5%	3%	4%	19.5%
2016	14%	3%	4%	21%
2017	15.5%	3%	4%	22.5%
2018	17%	3%	4%	24%
2019	19.5%	3%	4%	26.5%

2020	20%	3%	4%	27%
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Class I Requirements

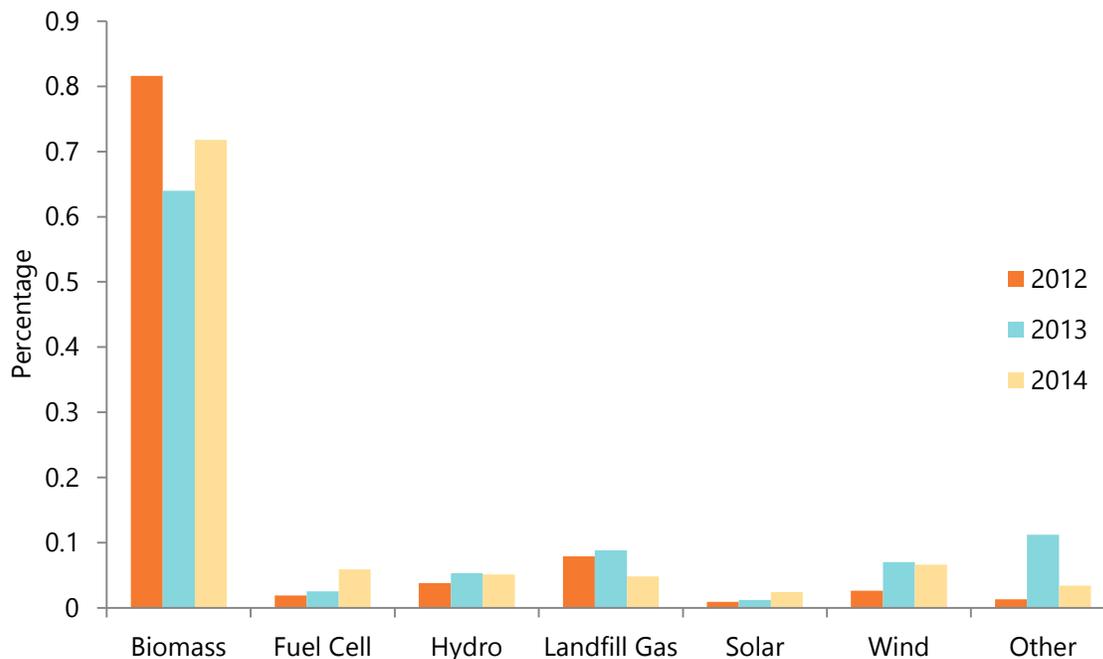
As shown in Table E2 above, Connecticut’s current Class I RPS requirement is 15.5 percent in 2017 and increases each year reaching 20 percent in 2020, and remains at 20 percent thereafter. Resources eligible for Class I include both zero carbon resources, such as solar and wind, as well as low-carbon resources, such as fuel cells, landfill methane gas, and biomass that meet certain emissions requirements. Class I renewable energy credits (RECs) have the highest potential value.¹² The purchase price for Class I RECs to meet the Connecticut RPS is effectively capped at \$55 per megawatt-hour, which is the statutorily established value of the Alternative Compliance Payment (ACP) that electricity suppliers may elect to pay in lieu of purchasing RECs.

The supply of Class I resources has kept pace with the growth in regional demand to date – through State programs, procurements and legacy generation – providing adequate RECs for Connecticut to meet its Class I RPS requirements each year. Most recent analyses indicate that there should be adequate Class I resources available to meet Connecticut’s Class I RPS goals in 2020.

Although Connecticut purchases many RECs for solar, wind, and other renewables through its procurements and statewide programs, the RECs that are generated and delivered to the EDCs through these programs are generally re-sold into the regional RPS market. It is the obligation of the EDCs through standard service and retail suppliers to meet the RPS requirements. Due to differences in eligibility requirements and ACP levels between states, Connecticut met the majority of Class I RPS requirement with biomass RECs. In 2014, Connecticut met 76 percent of Class I RPS requirement with biomass and landfill gas RECs (see Figure E2).

¹² One REC is created for every one megawatt of renewable energy generation, which enables the state to track RPS compliance. A REC is a tradeable commodity that allows an entity to hold the legal rights to the environmental benefits associated with renewable energy generation.

FIGURE E2: Connecticut RPS Class I Fuel Source, 2012-2014



Class II and Class III Requirements

Class II and Class III percentages have remained constant at 3 percent and 4 percent respectively. Refuse facilities, biomass and small hydro facilities that do not meet the Class I eligibility requirements generally are eligible for Class II. Class III resources are limited to combined heat and power and electric efficiency projects that do not receive any ratepayer funding. The Class II ACP was constant at \$55/MWh, while the ACP for Class III is \$31/MWh.

Recent legislation restructures the Class II tier of the RPS.¹³ Class II RECs will be limited to only waste to energy facilities that support Connecticut’s waste management goals to ensure we have sufficient in-state capacity to handle our waste production. In addition, the Class II REC requirement will increase from 3 percent to about 4 percent beginning in compliance year 2018 to support approximately 150 MW of trash to energy facilities located in Connecticut. Further, the ACP will be set at \$25/MWh in 2018. This will increase the value of Class II RECs providing needed support to waste to energy facilities in Connecticut. The cost to support the Class II RPS requirement of 4 percent at \$25/MWh is approximately \$27.5 million annually.

¹³ Connecticut General Assembly, Public Act 17-144, *An Act Promoting the Use of Fuel Cells for Electric Distribution System Benefits and Reliability* (2017).

RPS Regional Context

Connecticut's RPS policies must be viewed in a regional context. Electricity providers can satisfy their RPS requirements with RECs purchased from projects located in the ISO-NE control area or with energy imported into ISO-NE from an adjacent control area.

While the geographic eligibility rules are the same across New England, each state's RPS has different eligibility criteria, percentage requirements, and ACP prices. For example, unlike other states, Connecticut considers fuel cells and certain biomass facilities Class I resources and has a lower ACP for Class I. These differences among state's RPS design have important consequences for the type—and price—of renewable generation that electricity providers will buy to comply with Connecticut's RPS. Since the ACP is higher in those states, Connecticut is often the last to receive multi-state qualified RECs such as solar and wind when demand exceeds supply because those resources often get paid a higher price in other states.

Participating in a regional market for RPS compliance fosters lower cost compliance through greater competition and enables Connecticut to access low-cost renewable generation from areas with significant renewable resource potential. At the same time, limiting the RPS market to the same geographic boundaries as our regional electricity market ensures that the renewable generation supported through the RPS will compete with and potentially displace polluting fossil-fired generation in the regional electricity market, ensuring the benefits of lower energy prices, job creation, improved air quality, and economic activity are localized.

REC Price Trends

REC values are determined by the supply and demand for each class of resources. Currently there is a surplus supply of Class I so the price of RECs have declined from near the ACP of \$55/MWh in the beginning of 2016 to around \$30/MWh in the spring of 2017. Class II RECs sell for less than \$1/MWh, due to the excess supply in New England. Class III REC prices increased in 2015 and are now selling for approximately \$25/MWh due to Public Act 11-80 removing ratepayer funded efficiency programs from qualification as Class III.

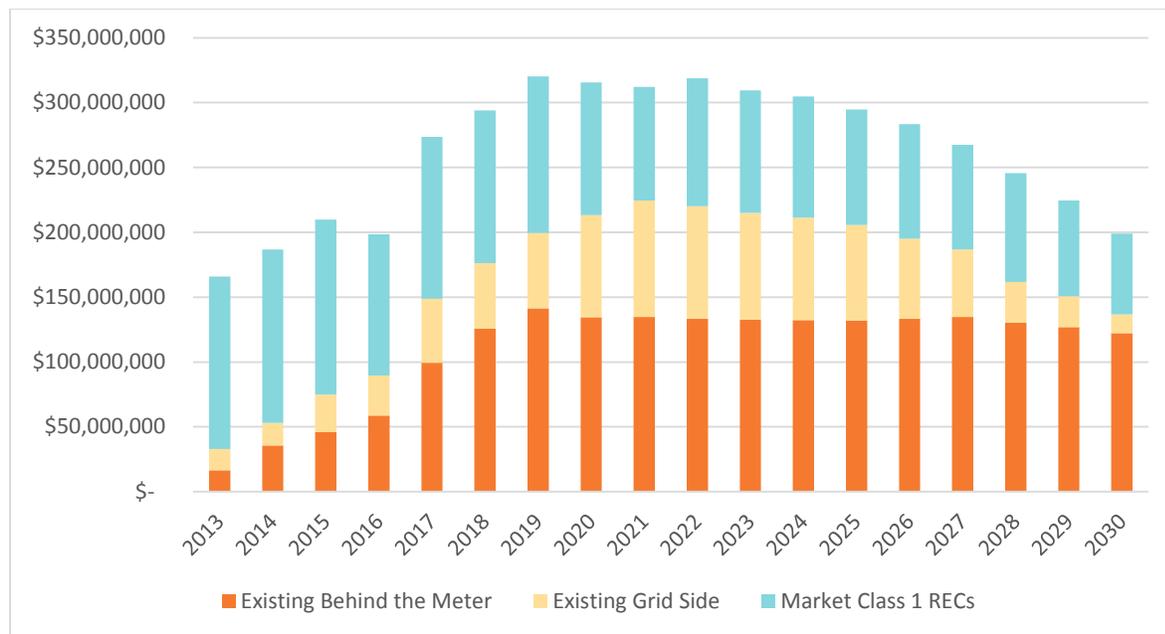
When first conceived, RECs were meant to be the primary means to finance renewable generation. In theory, REC revenue plus energy revenues would provide the total revenues necessary to finance renewable projects. However, these markets are volatile and may not be adequate to fund the full cost of renewable generation. Long-term contracts for energy and RECs have taken over as the way to finance new grid scale renewable projects. State incentive programs and net metering have been the primary way to fund behind the meter projects. The RPS still creates our renewable resource goals and is an effective method to identify, track, and trade attributes.

Renewable Portfolio Standard Costs

The Class I RPS standard is 15.5 percent of load in 2017. DEEP estimates that the annual cost of meeting our Class I RPS requirements is approximately \$250 million over the cost of producing the equivalent energy from conventional fossil resources in 2017. This estimate includes the costs associated with both the grid scale renewable procurements and Connecticut's behind the meter programs – the zero emission and low emission renewable energy credit program (ZREC/LREC) and the residential solar incentive program (RSIP) and solar home renewable energy credit program (SHREC), plus the net metering or virtual net metering costs associated with resources in those programs. The ongoing annual costs will continue to increase as new projects become operational and the RPS requirements continue to increase (see Figure E3 for the Net Annual Cost of the RPS). The cost is expected to increase to approximately \$300 million in the years ahead as the RPS goal increases to 20 percent in 2020 and new projects funded through our state programs and procurements become operational.¹⁴

¹⁴ The estimate of the net cost of the RPS does not include additional new grid or behind the meter programs; it only includes existing or approved programs/projects. The net cost for residential behind the meter projects was calculated by using the total cost of the projected electric rate (adjusting for the customer service charge), state subsidies, REC costs. For C/I behind the meter programs, net energy billing rates were forecasted using the annual growth rates in the 2017 AEO forecasts for electricity prices and only the volumetric charges were used to calculate the cost of the RPS; demand based charges were excluded from these estimates. For grid scale programs, DEEP utilized the total cost of the PPA, levelized utility cost (if the project was directly constructed by the EDC), additional REC costs, and discounted the projected cost of wholesale energy (i.e., the locational marginal price). These assumptions allowed DEEP to fairly account for the costs that the ratepayer would have incurred regardless of purchasing cleaner generation and properly estimate the actual cost of Connecticut's clean energy programs. See Appendix for further explanation of how the Cost of the RPS was calculated.

FIGURE E3: Net Annual Cost of RPS, 2013-2030, Class I Resources



Renewable Generation from Connecticut Sponsored Programs

The amount of renewable generation located in Connecticut has increased significantly since 2013 and will continue to increase in the years ahead. In recent years, there is a growing desire to support local, in-state clean energy resources over out-of-state resources as a way to further in-state job growth, improve system reliability, and to displace local fossil fuel generation.

The chart below shows the expected generation from all Class I renewable generation funded through Connecticut programs and procurements through 2035. The long-term contracts under these programs ensure there are no shortages in the regional RPS market, even though the EDCs may not necessarily retire the RECs from these programs specifically to meet their RPS obligations. The colored bars represent the RECs produced from contracted projects compared to projects supported as part of our current RPS market to meet the requirements of 20 percent by 2020 and beyond. Once the long-term contracts expire, these renewables are still eligible to participate in the regional REC market.

As demonstrated in Figure E4, in 2013, Class I generation from programs directly sponsored by Connecticut represented about 1.2 percent of Connecticut’s annual electric load. Most recently in 2016, projects directly sponsored by Connecticut represented about 3.6 percent of load, with 1.6 percent from behind the meter resources and the remaining 2.0 percent from grid scale. When all projects from Public Act 15-107, LREC/ZREC, and RSIP and SHREC become operational, the expected Class I generation from Connecticut sponsored programs represents approximately 12 percent of load in 2020. When comparing in-state Connecticut sponsored projects, most of the

Class I generation comes from behind the meter projects, which will represent around 5 percent of load for most of the forecast period and in-state grid scale projects will represent about 2 to 3 percent of load. Out-of-state Connecticut sponsored projects will hover around 3 to 4 percent of load throughout the forecast period as they become operational in the next few years.

The installed capacity of in-state behind the meter solar has grown to 280 MW (approximately 1.5 percent of load or 410,000 MWh) through 2016.¹⁵ DEEP expects the installed capacity of solar to grow to 650 to 700 MW (approximately 3.8 percent of load or 1.06 million MWh)¹⁶ by 2020, which would include projects already approved or additional capacity that has been authorized.¹⁷ With additional funds from LREC/ZREC that have not yet been exhausted, the amount of solar generation that comes from behind the meter facilities could grow to as much as 750 to 800 MW by 2021 (approximately 4.5 percent of load or 1.24 million MWh).¹⁸ In addition, DEEP recently selected projects that will be located in Connecticut, including 12 grid connected solar projects totaling 201 MW and one wind project of 3.5 MW.

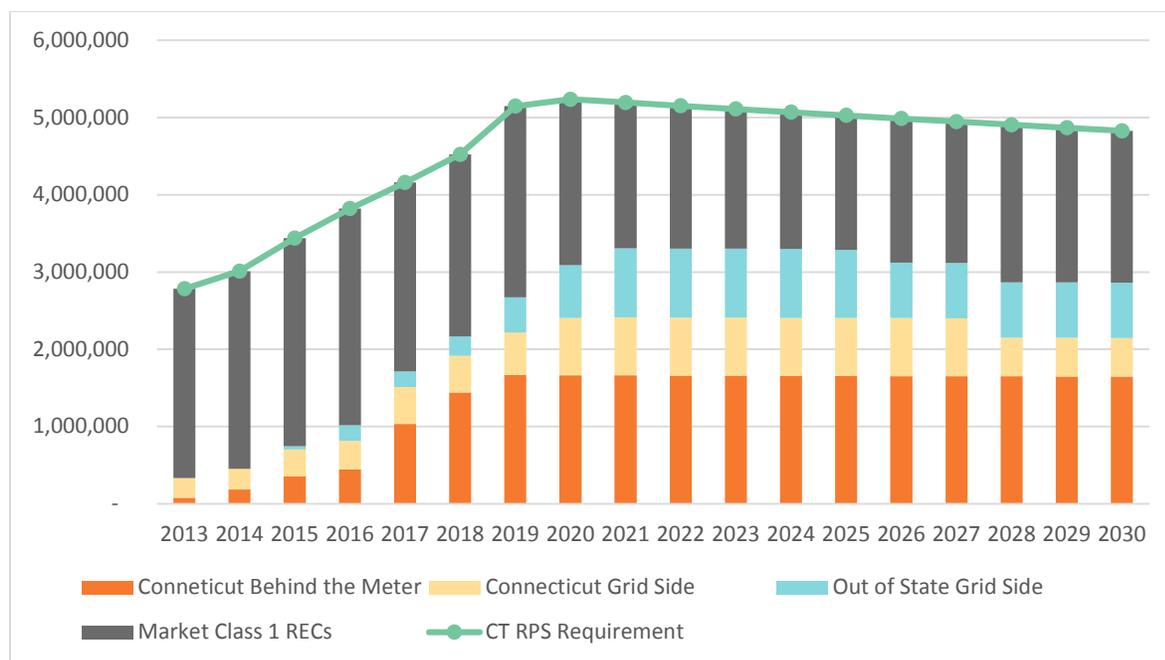
¹⁵ Based on 15 percent capacity factor for Residential (160 MW) and 19 percent capacity factor for C/I projects (120 MW).

¹⁶ Based on 15 percent capacity factor for Residential (300 MW) and 19 percent capacity factor for C/I projects (400 MW).

¹⁷ DGFWDG Final 2016 PV Forecast.

¹⁸ Based on 15 percent capacity factor for Residential (300 MW) and 19 percent capacity factor for C/I projects (500 MW).

FIGURE E4: In-State v. Out-of-State Production from Connecticut Programs and Contribution to Regional Market Relative to Current CT Class I RPS Requirements (MWHs)



Grid Scale Renewables – Competitive Procurements

The cost for renewable generation technologies continues to decline. In general, grid-connected renewable projects provide similar benefits at a lower cost to ratepayers compared to behind the meter projects. DEEP has issued multiple solicitations for grid connected clean energy generation and selected the following resources:

TABLE E3: DEEP Grid-Connected Procurement Authority for Clean Energy Generation

Successive competitive procurements for renewable energy projects have resulted in significantly declining renewable energy generation prices for the selected winning projects. For instance, in 2011, under Section 127 of Connecticut Public Act 11-80, 10 megawatts of renewable generation was added to the state’s renewable energy portfolio, with an average price of 22.2 cents/kWh for the two selected solar projects. Subsequently in 2013, under Section 6 of Connecticut Public Act 13-303, the EDCs contractually procured an additional 20 megawatts of solar generation, which resulted in a selected bid price of approximately 12 cents/kWh. The most recent grid connected solar and wind projects selected in the Three State and Small Scale Clean Energy requests for proposals (RFPs) resulted in a selected bid price of approximately 9 cents/kWh on a levelized basis

Authority	Eligible Resources	Procurement Authorization (% load)	Approximate Authority Remaining (% load)
Section 6 of P.A. 13-303	Class I renewables	4%	2.6%
Section 7 of P.A. 13-303	Class I renewables, large-scale hydropower	5%	5%
Section 8 of P.A. 13-303	Run-of-the-river hydropower, landfill methane gas, biomass, fuel cell, offshore wind, anaerobic digestion, energy storage	4%	3.27%
Public Act 15-107	Passive demand response, Class I renewables (including Class I balanced with hydropower), Class III sources, large-scale hydropower, natural gas capacity, LNG	10%	6.81%
June Special Session Public Act 17-3	Eligible nuclear power, hydropower, zero-emission Class I renewables, energy storage	43.6%	43.6%
TOTAL		66.6%	61.28%

over the 20-year life of the projects.¹⁹ These grid scale procurements demonstrate that larger volumes of renewable energy can be procured at lower rates when obtained through competitive solicitations. In addition, the recent Small Scale Procurement demonstrates that small solar grid scale projects can be developed in Connecticut under 10 cents/kWh on a levelized basis.

TABLE E4: DEEP Solicited Grid-Connected Clean Energy Generation

Authority	Resource(s) and MW Selected
Project 150	Biomass – 30 MW Fuel Cell – 63 MW
Section 127 of P.A. 11-80	Solar – 12.2 MW Wind – 5 MW Fuel Cell – 12.8 MW (5.6 MW operational)
Section 6 of P.A. 13-303	Solar – 20 MW (2013); 240 MW (2016) Wind – 250 MW (2013); ²⁰ 154.8 MW (2016) ²¹
Section 8 of P.A. 13-303	Biomass – 29.6 MW
Public Act 15-107	Solar – 324.5 MW Wind – 43.5 MW Passive Demand Response – 34 MW

¹⁹ Levelized means the net cost to install the technology is spread out over the expected output of the system, which is typically 20 years.

²⁰ This facility was procured by DEEP in a 2013 solicitation but will not come online under DEEP’s procurement authority because of interconnection issues.

²¹ Connecticut procured these facilities through the Three State RFP and will be splitting the output from these projects with Massachusetts.

Connecticut's utilization of long-term contracts or power purchase agreements (PPAs) as a mechanism to secure development and delivery of renewable power has been an issue for generators as well as ISO-NE, which considers such contracts to be out-of-market subsidies. Connecticut has successfully defended these contracts against legal challenges claiming these long-term contracts are not appropriate in unregulated generation markets.²² Although the federal court upheld the legality of Connecticut's programs, DEEP is engaged in a regional stakeholder process to see if other mechanisms and regional market rules can be developed to accommodate the desired growth in renewable generation through other mechanisms.

Grid Scale Renewable Siting

While the costs of grid connected clean energy resources have declined, siting larger scale wind and solar projects has raised challenges in balancing the deployment of renewable resources with potential environmental impacts to prime and important farmlands, core forests, protected and endangered species and other environmental/land use considerations. Interconnection and delivery can also be expensive and difficult. Much of the wind potential is offshore or is in northern New England in areas that do not have adequate transmission facilities to move the power to load centers in southern New England.

In its Three State and Small Scale RFPs pursuant to Sections 6 and 7 of Public Act 13-303 and Public Act 15-107, DEEP collaborated agency-wide to assess the environmental impacts of all proposals submitted. DEEP evaluated the environmental siting impacts as part of the qualitative evaluation of bids which accounted for 25% of the total score. The majority of DEEP's scoring, 75%, in its selection process was the quantitative evaluation, which is primarily the price of bids. DEEP made pricing an important factor of the RFPs because the major purpose of P.A. 15-107 was to address electricity price spikes during the winter and related winter reliability.

In response to DEEP's selection decision in its Three State and Small Scale RFPs, the Council on Environmental Quality released a report with recommendations for better siting of renewable energy facilities to limit impacts on prime and important agricultural and core forests.²³ On January 10, 2017, DEEP and the Connecticut Department of Agriculture co-convened a workshop on the siting of utility-scale clean energy projects as part of its 2016 Comprehensive Energy Strategy proceeding. One major theme resulting from the workshop is that large tracts of flat, cleared land, which often includes farmland, is the most attractive siting location from a developer's perspective because it is the most inexpensive and easiest to develop. However, the state of Connecticut has invested significant time and expense to protect and preserve prime

²² *Allco Finance Ltd. v. Klee*, 861 Fed. 3rd (2d Cir. 2017).

²³ Connecticut Council on Environmental Quality, "Energy Sprawl in Connecticut: Why Farmland and Forests are Being Developed for Electricity Production; Recommendations for Better Siting" (Feb. 3, 2017).

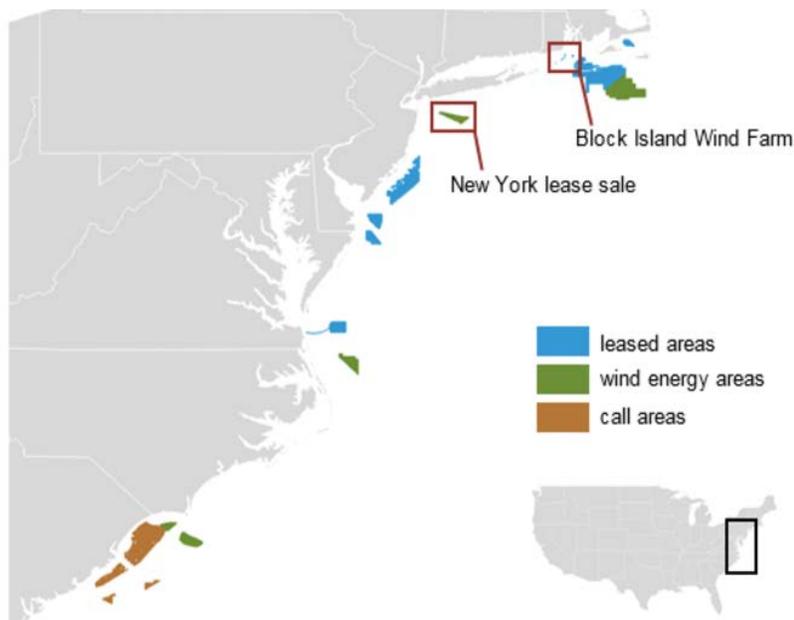
farmland. There needs to be a balance of energy priorities and preservation priorities, while also recognizing the opportunity that clean energy can provide to farmers who may use a portion of their farmland to site renewables and help fund farm operations on the remaining land. In the 2017 session of the General Assembly, both the Energy & Technology and Environment Committees raised bills to address the issue around the siting of renewables, which ranged from requiring DEEP to convene an advisory board to establish a renewable siting plan, to effectively banning the siting of solar PV on prime farmland.²⁴ The General Assembly passed Public Act 17-218, which requires DEEP to consider certain environmental impacts related to siting in future solicitation and requires the Connecticut Siting Council to consider similar environmental and agricultural land use impacts in its proceedings.

Offshore Wind

Offshore wind can result in grid scale renewable energy without the renewable siting concerns raised in DEEP's recent grid scale solicitations. The federal government issues leases for offshore wind energy projects as state jurisdiction only extends three nautical miles from the coast. Federal jurisdiction, known as the exclusive economic zone, extends 200 nautical miles from the coast and is managed by the Bureau of Ocean Energy Management (BOEM). As of June 2017, BOEM has issued 11 leases for offshore wind development, including sites off the coast of Rhode Island, Massachusetts, New York, and New Jersey.

²⁴ S.B. 943, *An Act Concerning the Installation of Certain Solar Facilities on Productive Farmland* (2017); H.B. 6547, *An Act Concerning A Connecticut Green Plan and Land Resource and Use Inventory for Energy Infrastructure* (2017).

FIGURE E5: Federal Offshore Wind Leasing Areas along the U.S. Atlantic Coast



Source: U.S. Energy Information Administration, based on Bureau of Ocean Energy Management

Rhode Island has experience navigating the first offshore wind project in the U.S., though a number of other states have also been actively promoting offshore wind development. New York’s Governor Cuomo has proposed developing 2,400 MW of offshore wind by 2030. The New York State Energy Research and Development Authority (NYSERDA) released its Offshore Wind Master Plan in 2017 that outlines guidelines and recommendations for developers, and plans to solicit bids in 2018.

In Massachusetts, the state legislature passed legislation in 2016 for electric utilities to procure up to 1,600 MW of offshore wind energy by 2027. Electric utilities in Massachusetts released a solicitation for 400 MW of offshore wind in June 2017, and expect to announce bid winner(s) in May 2018. Other states are allowed to contract for additional capacity as part of the solicitation, as long as Massachusetts ratepayers are not negatively affected. The Massachusetts Clean Energy Center has also conducted several offshore wind studies that provide relevant insights for neighboring states. With the enactment of Public Act 17-144, DEEP issued a notice of proceeding on November 8, 2017 that it intends to issue a draft RFP by December 15, 2017 for clean energy resources, including offshore wind. PA 17-144 gives DEEP the authority to procure a variety of energy resources, including up to 3 percent of load from offshore wind.

Regional Market Rules Governing Renewables

Existing competitive wholesale energy markets are not currently designed to achieve state policies, particularly environmental policies. Because of this market deficiency, state legislatures have implemented legislation that requires the direct purchase of renewable energy and RECs to encourage renewable generation retention and development.²⁵ Generators have raised concerns that these contracts make renewable generation more competitive, thus reducing markets prices and potentially pushing out those generators reliant on market revenues. ISO-NE and FERC have grown concerned that the states are interfering with the market by providing “out-of-market subsidies’ through long term contracts and have instituted rules that “mitigate” the effects of these contracts. This mitigation has created a tension between state law and policy, on the one hand, and the “idealized vision of markets free from influence of public policies” held by market proponents.²⁶ This tension has created uncertainty in the markets and significant litigation. In an attempt to resolve the tension and provide for a more certain future, the stakeholders have embarked on a process known as Integrating Markets and Public Policy (IMAPP). Similarly, FERC conducted a technical conference on May 1 and 2 to receive input on this issue, not only in New England but in the other eastern regional transmission organizations of New York ISO and PJM Interconnection.

The IMAPP process to date has encompassed eight meetings in which stakeholders have put forward several ideas. The ideas that have been put forward in IMAPP can be characterized into two major categories: those that are intended to achieve state policies, and those that are intended to accommodate state policies. ISO-NE has also brought forward a proposal known as Competitive Auctions with Subsidized Policy Resources (CASPR). The basic concept of CASPR is that generation resources that receive state contracts and are mitigated by ISO-NE will be able to take the place of retiring resources or other new resources in a secondary auction. Unfortunately, the CASPR proposal currently removes a market rule exemption from mitigation of up to 200 MW per year of renewable resources (excluding most hydro resources). In addition to other concerns, Connecticut strongly objects to the removal of the 200 MW exemption in the ISO-NE proposal. Connecticut, however, continues to work through the stakeholder process to see if the CASPR proposal, and other proposals, can better achieve an effective market that accommodates state policies. Connecticut has made clear that any market rule change that does not allow the states to achieve state policies will ultimately be unsuccessful. Connecticut believes that the market and state policies can coexist and we are committed to the process of finding the best path forward to achieve this goal.

²⁵ Public Act 13-303, Public Act 15-107; 83A, C, and D of the Massachusetts Green Communities Act, and Chapter 31 of Title 39 of the General Laws of Rhode Island.

²⁶ FERC Docket No. EL16-92 (2017) Bay, *concurring*.

Behind the Meter Renewables

Behind the meter clean energy resources, refers to generation that is installed by customers to supply power to their homes or businesses. From the perspective of the regional grid, behind the meter projects reduce the electric load of the area where the clean energy facility is located.²⁷ Connecticut has several programs to support deployment of local clean energy by purchasing the RECs associated with behind the meter systems. These programs include LREC/ZREC for commercial and industrial installations under 2 MW and 1 MW, respectively, and RSIP and SHREC for residential installations. These programs are discussed in more detail below.

DEEP recognizes the benefits that behind the meter renewables provide to the electric grid, including but not limited to reducing system line losses, potentially delaying the need for transmission and distribution infrastructure, reducing electric bills for participating customers, increasing resiliency and energy security, contributing to economic development in Connecticut, and potentially encouraging positive land-use.

Net Metering

Net metering is a tariff (or compensation structure) available to electric customers who install renewable power generation on their own premises, frequently referred to as “behind the meter” generation because the generator is located behind the utility’s meter for the house. Class I renewable energy facilities that have a nameplate capacity of 2 megawatts or less are eligible for the tariff. Net metering has been a key incentive in promoting the installation and deployment of Class I behind the meter distributed generation in Connecticut.²⁸

Net metering and virtual net metering are administered by the utilities under a PURA approved tariff rather than separate contracts for each project. The tariff structure minimizes the administrative burden because there is no procurement and signing up for a tariff is straightforward for the utility and the generator. Prices adjust automatically when retail rates change.

In accordance with Section 16-243h of the General Statutes, net metering allows customers with behind the meter renewable energy facilities such as rooftop solar to offset each kWh they use

²⁷ In net metering, the building where the generation is located is credited for the reduced load, while in virtual net metering, a building located in a separate location from the generation is credited for the reduced load.

²⁸ Net metering began in Connecticut in the 1980s. At that time it was primarily for small combined heat and power systems fueled by natural gas. These tariffs are still available today. The size of the system was limited to 50kW and netting is done on a monthly basis. Excess generation was, and is currently, paid at the average monthly wholesale generation rate. In 2000, net energy billing was modified and a new tariff was opened for Class I resources under Connecticut’s RPS.

on their electric bill with energy generated by their renewable energy facility. The customer is credited on the electric bill from the EDC by subtracting or “netting” the onsite electricity generation against their electricity consumed in any given month at the full applicable retail rate of electric service, minus the customer service charge that the customer pays for the electricity they purchase from the EDC. This offset or credit of generation allows customers that install a behind the meter generation to reduce their electric bills. This offset or credit changes every year due to changes in electric supply and delivery rates. For example, in 2016 the offset and credit was approximately 17.5 cents/kwh for residential customers. However, in 2015 the offset and credit was approximately 21.3 cents/kwh.

Commercial and industrial (C/I) customers are also allowed to offset all volumetric charges, but not customer charges or demand based charges. Demand-based charges generally make up a large portion of C/I electric bills. Because net energy billing only allows netting of volumetric charges, C/I customers are compensated less for their behind the meter generation on a cents/kWh basis than residential customers. For example in 2016, on average, C/I customers were allowed to offset 10.77 cents/kwh through net energy billing. The generation portion of that offset was about 9.15 cents/kwh and the delivery component was about 1.62 cents/kwh.

A net metering banking period is permitted for one year. If a customer’s generation exceeds their consumption in any given month during the annual period, the credits are rolled over into the following month. Any excess credits at the end of the year are compensated at the avoided cost of wholesale power (equivalent to approximately 3.6 cents/kWh in 2016).²⁹ Under net energy billing, the tariff compensates the customer for the energy, but not the renewable attributes, which are generally sold into the regional market. Unlike other states, such as Massachusetts, there is currently no cap on the amount (MW or percent load) of Class I resources eligible for net metering in Connecticut.

Virtual Net Metering

In 2011, the legislature enacted virtual net metering. Virtual net metering is limited to specific customer classes: agricultural, state, and municipal customers. Virtual net metering allows multiple customers to net their electric consumption against the generation from a Class I generation facility. The participating customers do not have to be physically connected to the renewable resource. The program initially provided aggregate credits of up to \$10 million annually split among the three classes, with no individual class receiving more than 40 percent of the total dollar

²⁹ <https://www.eversource.com/Content/docs/default-source/ct---pdfs/rider-n-historic-cash-out-prices.pdf>. The significantly lower price paid for excess credits incentivizes the sizing of the generation facility to be roughly the same as the location’s demand.

allocated. Subsequent pieces of legislation provided for an additional \$6 million for municipal customers and \$3 million for agricultural customers.³⁰ Virtual net metering has already reached its cap for municipal customers and therefore no additional municipal projects can participate in the program.

Net Metering and Virtual Net Metering: Direct Ratepayer Costs and Benefits

The direct cost and benefits of net metering and virtual net metering from a ratepayer perspective are not easily understood and can vary widely based on the customer's rate and service territory. As discussed below, the value of the credits can also vary significantly for essentially the same generation, depending on whether a customer is eligible for net metering or virtual net metering. In addition, since electric rates and rate structure varies between customer classes and utilities, the savings that customers receive from the generation can vary between the EDCs and the rate class of the customer. For example, residential rates are higher than commercial and industrial rates, and therefore, residential customers are able to offset higher charges, and effectively are paid more for their solar generation than C/I customers. In addition, C/I rates include demand based charges, which are set by a customer's maximum demand in a month or year. These are harder to avoid because a customer's maximum demand can occur at any given time. So if a C/I customer who uses self-generation (i.e., PV, fuel cell, etc.) has a maximum demand outside of the PV system's production period, then that customer will incur the same demand charges, regardless of the amount of PV generation. This is due to customers only being allowed to offset volumetric charges, not demand based charges. Rates are also generally higher for United Illuminating (UI) customers than Eversource. UI residential customers, therefore, are effectively paid more than Eversource customers are for the same generation.

Net metering and virtual net metering rates are also very uncertain over the life of the project since they are based on retail rates that are subject to changes in rate design. These variations in pricing have nothing to do with the costs or benefits of the generation, which is more related to when and where the energy is delivered and the avoided cost, i.e., the costs of distribution and transmission investments foregone as a result of adding a distributed generation resource. When and where generation is delivered are key factors in energy pricing in wholesale markets and power purchase agreements with wholesale generators; however, these factors have little if any impact on the price paid for generation under current net energy billing arrangements.

³⁰ Public Act 16-216, An Act Concerning Authorizations Relating to Virtual Net Metering. Public Act 17-218, An Act Concerning the Installation of Certain Solar Facilities on Productive Farmlands, Incentives for the Use of Anaerobic Digesters by Agricultural Customer Hosts, Applications Concerning the Use of Kelp in Certain Biofuels and the Permitting of Waste Conversion Facilities.

In addition, most behind the meter projects in Connecticut participate in REC monetization programs offered by the Green Bank or LREC/ZREC, where participants receive additional revenue for selling the RECs to the utilities (which is ultimately paid for by all ratepayers). These incentives lower the cost to participants, but are a cost to all other ratepayers that must fund these incentives. When the total cost of net metering and these incentives are included, the ratepayer total cost of behind the meter renewable programs is over 20 cents/kWh today and will increase in the future as electric rates increase.

In addition, most behind the meter generation requires additional subsidies from the Green Bank or LREC/ZREC programs in order to be built. The budgets for the LREC/ZREC, RSIP, and SHREC programs that purchase the RECs of the system therefore provide a limitation on the number of behind the meter projects that are developed each year.

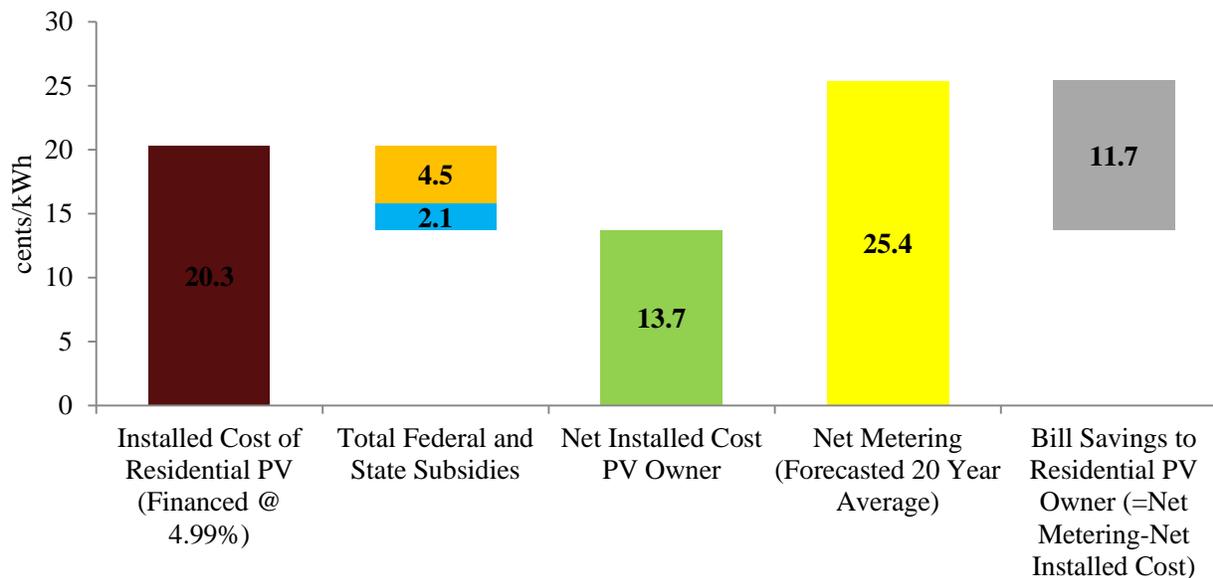
Direct Costs and Benefits of Net Metering

In 2016, the total installed cost of a 8.6 kW residential rooftop solar system was approximately 20.3 cents/kWh on a levelized basis over 20 years. This installed cost figure also accounts for any interest costs that the PV customer would incur from financing their PV system through a loan. The net cost for a customer purchasing a rooftop solar system is approximately 13.7 cents/kWh after federal tax incentives and state subsidies (i.e. Green Bank subsidy).³¹ Over a 20 year period, the customer is expected to offset the generation they use with production from their solar facility at the full retail electric rate of 25.4 cents/kWh, resulting in a net savings of about 11.7 cents/kWh or about \$82/month.³² However, there may be additional O&M expenses and equipment replacement costs that rooftop solar customers may experience over time, which are not accounted for in this example.

³¹ The combined value of the Federal and State subsidies is approximately 6.5 cents/kWh.

³² Interrogatory response from the Connecticut Green Bank. Costs were provided in nominal dollars. Financing costs were calculated at a 4.99%.

FIGURE E6: Cost of Solar, from PV Homeowners Perspectives³³

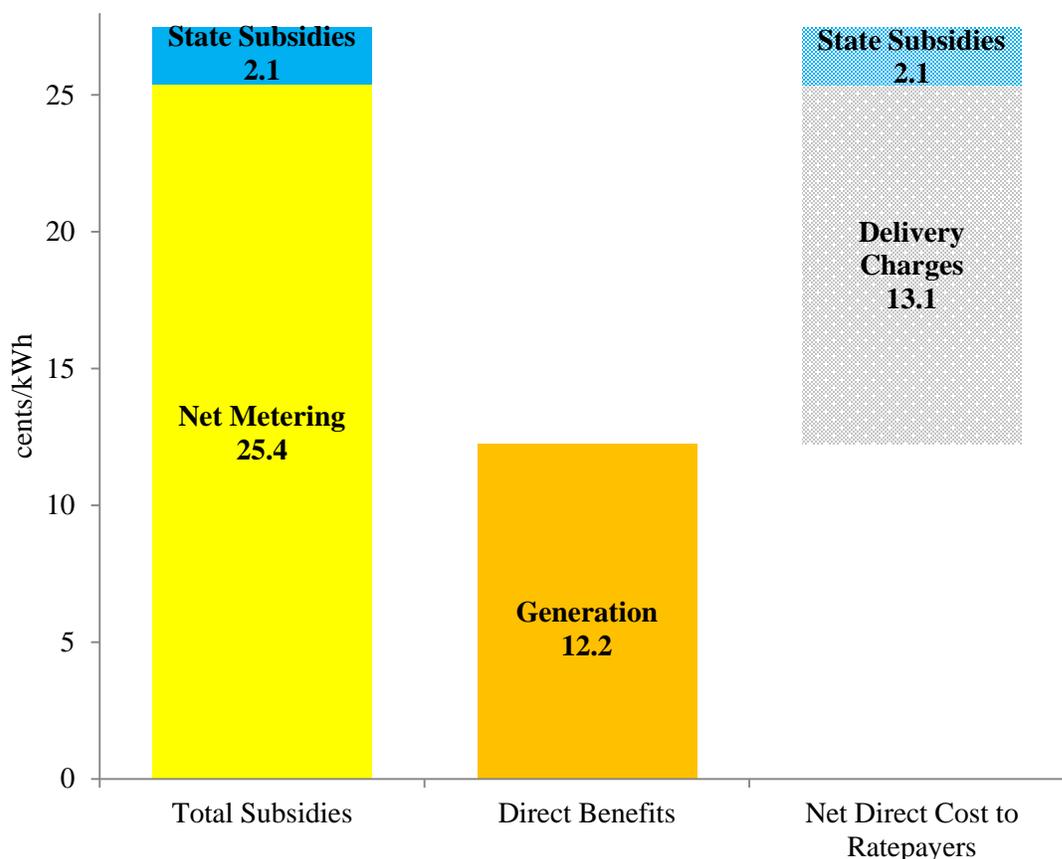


The offset in retail rates results in significant bill savings to participants. These savings to the participating customer that result from net energy billing provide a substantial return for the participating customer. Through net energy billing, this return is paid through electric bill savings rather than a direct payment. These bill savings in the form of reduced electricity bills, however, are a real cost of rooftop solar that all other ratepayers must pay. When designing programs, policy makers consider the costs of programs, such as net metering, from the perspective of all ratepayers, not just the program participants. The total cost to Connecticut ratepayers for residential rooftop solar is 27.2 cents/kWh. This is the cost of net energy billing, or 25.4 cents/kWh (the retail residential electricity rate), plus Green Bank incentives, or 2.1 cents/kWh³⁴, to encourage solar development. In contrast, grid scale solar now costs less than 10 cents/kWh on a levelized basis in nominal dollars. The benefits of behind the meter purchases accrue to solar owners more than non-participant ratepayers, while the grid scale projects and distributed generation provide benefits to all ratepayers.

³³ This scenario is based on an average PV homeowner-purchased system in 2016, and not on a leased system. Installed cost is levelized at 20 years and 5% discount rate is applied. Net metering rate is a forecasted amount over 20 years.

³⁴ State incentives are the RSIP subsidy levelized over 20 years. This subsidy is offered directly by the Green Bank.

FIGURE E7: Direct Costs and Benefits of Behind the Meter Solar from Residential Electric Ratepayer Perspective (20 Year Levelized Cost, Nominal\$)³⁵



As demonstrated in Figure E7 above, the net cost to ratepayers of 15.2 cents/kWh is the cost above the forecasted avoided costs of traditional fossil generation and costs of some distribution and transmission costs that are not avoided by net metering ratepayers. This cost must be collected from other ratepayers and therefore raises electric rates in the long term. The direct benefits to ratepayers in Figure E7 are the avoided costs, which are the quantifiable monetary benefits that a net metering ratepayer provides to all ratepayers.

First, a behind the meter facility provides electric generation to the grid, which avoids the need to generate power from another generation facility. Thus, compensating a net metering ratepayer

³⁵ DEEP’s estimates are based on 20-year levelized values. DEEP evaluated CL&P and UI’s historical generation rates when compared to the total electric rate for residential customers. DEEP determined that the generation portion of the bill accounted for about 53 percent of the total electric rate. DEEP further estimated that the net metering rate was about 21.3 cent/kwh on average during the forecast period. DEEP applied the 53 percent coefficient to the forecasted net metering rate to determine the avoided generation costs over a 20-year period. Delivery charges are assumed to be composed of various charges including, T&D, C&LM, SBC, Renewables, FMCC-Delivery, etc.

for this avoided generation energy and capacity does not impose additional costs on the remaining ratepayers (e.g. utilities would need to buy power anyway).

Second, the net metering customer may provide some transmission and distribution (T&D) benefits to all ratepayers because the electricity is generated close to where it is consumed and thus does not need to travel long distances. However, not all T&D costs are avoided by the behind the meter generation because the net metered ratepayer must still have power from the grid delivered for its electric usage, meaning a net metered ratepayer incurs some T&D costs. Most T&D costs are collected from customers through volumetric kWh charges. Under the current net metering structure, distributed generation customers can completely offset these volumetric charges. This means that the net metering ratepayer may not pay for any T&D costs, although they continue to be connected to the grid and rely on the grid when their behind the meter system is not producing electricity.³⁶ In addition to generation and potential T&D benefits, behind the meter distributed generation may also reduce prices in the energy and capacity markets. This is called Demand Reduction Induced Price Effects or "DRIPE".

The costs collected through the systems benefits charge (SBC) and the non-bypassable federally mandated congestion charge (FMCC) are not related to consumption, but they are recovered from residential customers through volumetric charges. A net metering customer would be able to offset these costs as well. However, most of the T&D costs as well the sources of other SBC and FMCC charges are not actually avoided by the generation of individual net metered renewable energy, meaning the costs remain and must be recovered from remaining non-participant ratepayers. Consequently, the unavoided costs are shifted to ratepayers, raising electric rates over time. As demonstrated in Figure 7 above, the net cost of a residential net metering facility to all ratepayers is approximately 15.2 cents/kWh, which is made up of the unavoided T&D, SBC, and FMCC charges of 13.1 cents/kWh plus the cost of 2.1 cents/kWh ratepayer funded state subsidy.

Since the compensation rates through net energy billing are directly tied to retail electric rates, over time, higher electric rates translate into higher compensation levels for customers installing behind the meter systems. Higher credits for net metering over time is counter to the declining cost of most renewable generation that is declining each year. Therefore this link to retail rates could result in excess earnings for net metering customers and higher rates than necessary for remaining ratepayers in the future.

³⁶ Residential customer rates are based mostly on volumetric charges, which are allowed to be offset through net energy billing. However, in the case of C/I customers, a large portion of their electricity costs are composed of demand based charges which cannot be directly offset through net energy billing, but only through a reduction in their maximum demand, which can be achieved by self-generating power at the moment when the existing maximum customer demand is occurring.

Direct Costs and Benefits of Virtual Net Metering:

While net metering and virtual net metering have a similar billing structure, the pricing for virtual net metering differs from net metering because it limits how customer credits can be allocated to a customer's bill. Virtual net metering credits can apply to 100 percent of generation charges but are limited to apply to 40 percent of T&D charges. System benefit charges and NBFMCC charges cannot be offset under virtual net metering. These limitations reduce the possible credits for virtual net metering customers compared to those eligible for net metering.

In addition, the cash out for excess generation at the end of the banking year differs between net metering and virtual net metering. Under virtual net metering, excess generation is credited to the host account at the retail Standard Offer generation rate. In contrast, under net metering, excess generation is credited at the ISO-NE wholesale energy rate.

Behind the Meter Renewables - Residential

Residential Solar Investment Program (RSIP) & the Solar Home Renewable Energy Credit (SHREC)

Connecticut offers several options for residential homeowners to purchase a solar system or lease it from the developer. Generally, when a customer purchases the system, the entire cost of the system is paid up front, either out of pocket from the homeowner or through a financing arrangement. Many vendors also allow customers to lease the system and make a fixed monthly payment to the developer. The developer then installs the solar system on the customer's house. The customer receives credit for each kWh that is produced from the solar system, which offsets kWh's the customer uses when the system is not producing any energy and reduces the customer's electric bill. The savings from lower electric bills provide the incentive for customers to purchase the solar system. In general, leased systems require a smaller upfront investment, and correspondingly result in lower savings.

The Connecticut Green Bank (CTGB) implemented the Residential Solar Investment Program (RSIP) in 2012, which made solar PV technology more accessible and affordable to households through innovative incentives and financing. As part of its commitment to the residential sector through the RSIP, the CTGB has deployed a website that allows homeowners interested in installing solar PV systems to compare installation prices among contractors who participate in the program. Through 2016, the RSIP has facilitated the installation of more than 20,000 installations consisting of approximately 160 MW of residential solar capacity in Connecticut. With the passage of Public Act 15-197, An Act Concerning the Encouragement of Local Economic Development and Access to Residential Renewable Energy, the CTGB is authorized to offer residential rooftop solar incentives for up to 300 MW through 2021 known as the Solar Home Renewable Energy Credit (SHREC) program.

Shared Clean Energy Facility Pilot Program

Many homes across Connecticut are not suitable for solar because of the orientation of their home or shading. Others are not eligible because they are renters which may prohibit them from installing solar. Shared clean energy programs (often called “community solar”) are intended to provide customers access to the benefits of clean energy that they would otherwise not have. Shared clean energy programs provide these customers an opportunity to generate clean renewable power to meet their electric needs and lower their electric bills, which is particularly important for low and moderate income customers for whom energy costs (or energy burden) are a significant percentage of their monthly expenses.

Passage of Public Act 15-113, An Act Establishing a Shared Clean Energy Facility Pilot Program provided the statutory framework for shared clean energy programs in Connecticut. DEEP has been working on developing a pilot program since the summer of 2015. This program encourages both facility purchase and lease arrangements. The only cost structure difference between the pilot program and traditional net metering and virtual net metering is that rather than crediting production on a kWh basis, the developers receive compensation for the generation produced on a cents/kWh basis each year of the contract based on their bid proposal. This provides more transparency into the cost of the program and greater certainty to both the developer and participating customers as to the amount of the credit. Fixed purchase rates are more transparent than kWh credits because the value of the credit is known and will not change due to changes to electric rates or rate structure.

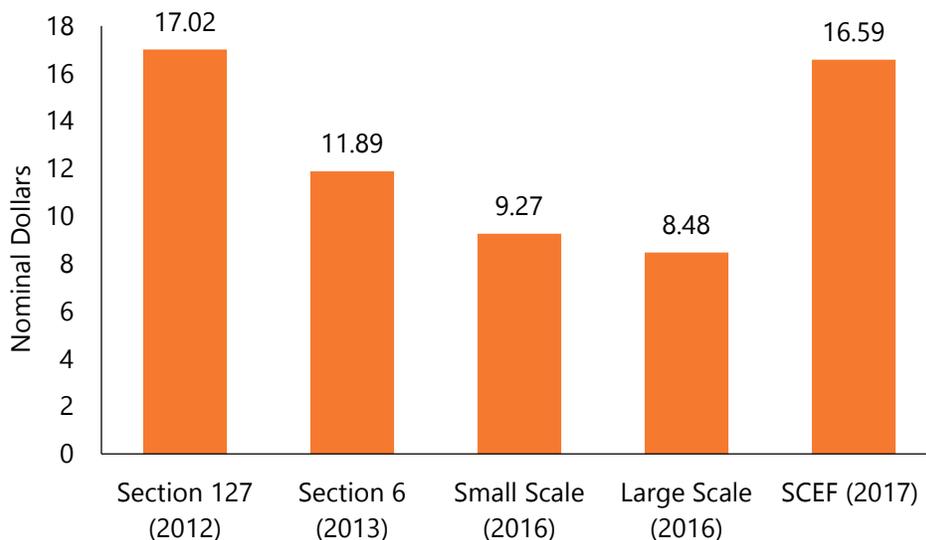
Community solar projects are configured in a manner similar to virtual net metering projects. Both have a centralized renewable generation facility with remote accounts that receive credit based on production. While community solar operates the same as virtual net metering, the relationship between the facility, host and accounts differs. In the existing virtual net metering program, the facility is located on a host’s property, or a property leased by the host, and all of the accounts are related to the host. For example, a municipality may locate a solar project at the high school then designate other town buildings as the beneficial accounts. Similarly, a farmer may locate a project on their farm then designate several other farm buildings that are separately metered as the beneficial accounts. In contrast, community solar may be located anywhere, the host need not have an electric load to offset, and subscribing customers generally do not have to have any relationship with the host or each other. However, community solar customers that purchase the solar panels through an upfront payment or a fixed price lease arrangement would help finance the facility. These customers directly contribute to the development of a renewable energy project and receive a payment or credit on their electric bill similar to those customers purchasing rooftop systems.

In February 2017, after a disappointing response to the initial SCEF RFP, DEEP re-issued the RFP to incorporate several changes. These included: a price cap, restrictions on siting, limitations on the percentage of subscriptions for commercial and industrial customers, minimum percentages of low and moderate income (LMI) customers, and a move toward an EDC-managed credit structure for the program.

DEEP received nine bids for community solar projects from four developers in response to the re-issued RFP. None of the proposals required an upfront financial payment or other meaningful financial participation by the customers. Participating customers will simply receive a credit for up to 2 cents/kWh or more for their portion of the production from the facility. However, the winning bids in the improved re-issued RFP did come in under the target price, achieved significant levels of participation by LMI customers, and were sited on brownfields or similar underutilized lands that were not prime farmland or core forest.

On June 2017, DEEP selected three projects to move forward, totaling 3.62 MW in Eversource territory and 1.6 MW in UI territory. The average price of the selected projects is 16.59 cents/kWh.

FIGURE E8: Cost of Clean Energy Programs, SCEF and Grid Scale (nominal dollars)



Source: DEEP analysis

Behind the Meter Renewables – Commercial

Public Act 11-80 established the LREC and ZREC programs. These programs, launched in the summer of 2012, provide an incentive to commercial and industrial companies to develop behind the meter clean energy projects by monetizing project RECs. The EDCs enter into long-term

contracts with those developers to purchase the renewable energy credits produced from such generation (not energy or capacity from these facilities).

There are two auctions based on project sizes and technology types. The ZREC program allowed for \$720 million in total spending in auctions held over six years for renewable energy credits from zero-emission Class I renewable energy resources such as solar, wind, and small hydro) beginning in 2012. Beginning in 2012, EDCs must enter into \$8 million worth of long-term (15-year) contracts annually for six years. The final competitive auction for this program was initiated in April 2017 and was completed in June. However, passage of Public Act 17-144 extended the ZREC program for one year for up to \$4 million worth of long-term contracts.

The LREC program allowed for \$300 million in total payments for renewable energy credits from low-emission Class I resources such as fuel cells, biomass, and landfill gas that meet certain emissions standards. The LREC program requires the EDCs to enter into \$4 million worth of 15-year contracts annually for LRECs for five years, beginning in 2012. The LREC program, originally authorized until 2016, was extended for one additional year by the General Assembly with the passage of Public Act 16-196, An Act Concerning the Use of Microgrid Grants and Loans for Certain Distributed Energy Generation Projects and Long-Term Contracts for Certain Class I Generation Projects. Public Act 16-196 split the \$8 million allocated to the final year of ZREC equally between the LREC and ZREC programs. Public Act 17-144 extended the LREC program for one year for up to \$4 million worth of long-term contracts.

To date, the LREC/ZREC program has contracted for RECs totaling approximately 332 MW of capacity. Most of the contracted RECs (about 295 MW) are from solar capacity. The second largest are fuel cell projects, where the LDCs have contracted for a REC equivalent of 35 MW of fuel cell capacity. However, because fuel cells operate at about a 95% capacity factor the 35 MW translates to about 291,270 MWh/yr while the 295 MW of solar at a 15% capacity factor translates to about 387,630 MWh/yr. Solicitations for Year 1 through Year 5 have spent approximately \$759 million, which leaves approximately \$261 million remaining for additional contract awards in 2017.³⁷

ZREC projects are larger than residential solar projects. Since the inception of the LREC/ZREC program, the average size of a small ZREC project ranged from 39 to 51 kW, the average size of a medium ZREC project ranges from 170 kW to 210 kW. The average size of a large ZREC project ranges from 536 kW to 749 kW. Active LREC projects have an average size that ranges from 442 KW to 1,523. These projects generally are for commercial, industrial or municipal customers, in comparison to an average project size of approximately 7.5 kW for a residential solar PV

³⁷ DEEP data inquiry from EDCs

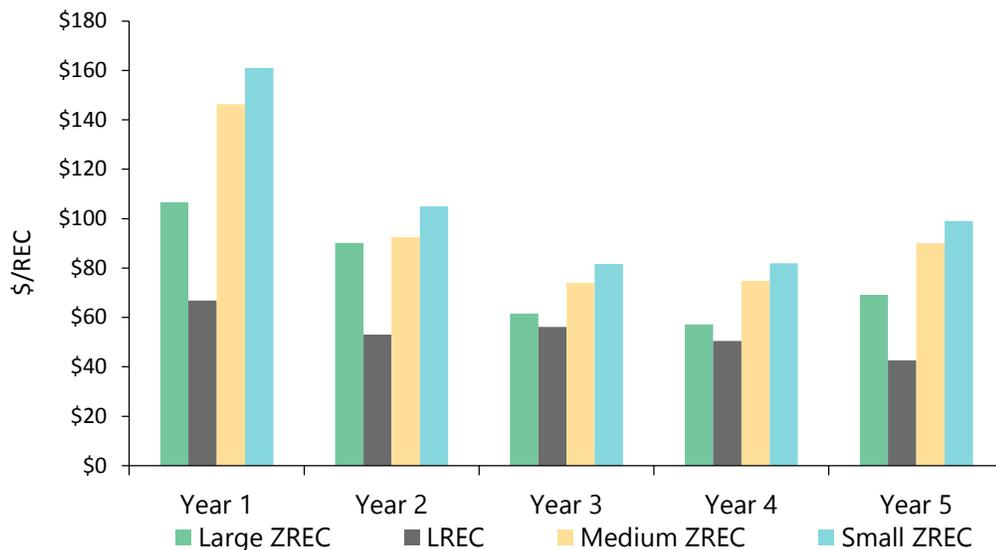
installation. ZREC projects are mostly solar, but other technologies like run-of-river hydropower facilities also participate in the program.

TABLE E5: Average Size of LREC/ZREC Projects (kW)

	Year 1	Year 2	Year 3	Year 4	Year 5
LREC	565	442	793	1,523	673
Large ZREC	536	550	786	749	749
Medium ZREC	170	181	184	180	210
Small ZREC	39	43	51	47	

The LREC/ZREC auction and competitive procurement process has brought down the cost of

FIGURE E9: Weighted Average REC Prices for Active LREC/ZREC Contracts



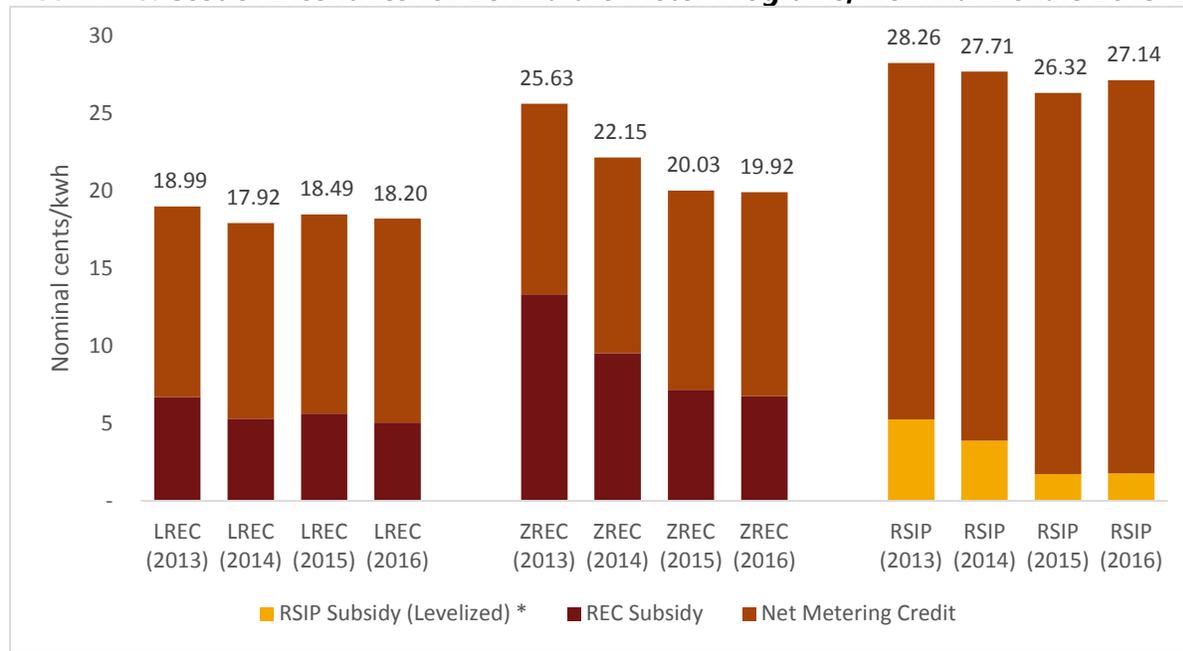
**One REC equals One Megawatt Hour of Energy*

RECs in the LREC/ZREC program. As noted in Figure E9, the Year five ZREC prices are approximately 35 percent to 39 percent lower than in Year 1. Year five LREC prices are approximately 36 percent lower than in Year 1.

The cost of the RECs, however, is only part of the overall cost of these projects. These projects may also qualify for net metering or virtual net metering. If LREC/ZREC bidders qualify for net metering, they can offset any volumetric charges, which increases the amount of revenues received for generation. Most projects in these programs use traditional net metering. Therefore, the gross cost of the program would be the LREC/ZREC costs, plus the cost of net metering.

When the costs of net metering and the ZREC are combined, DEEP estimates the gross costs of the program from projects participating in the first four years of procurements ZREC program to be 25.63 cents/kWh, 22.15 cents/kWh, 20.03 cents/kWh, and 19.62 cents/kWh respectively. With respect to LREC projects, the combined net metering and REC cost would be about 18.2 cents/kWh for projects chosen in Year 4.³⁸ These figures represent the gross costs of these projects that are paid for by all ratepayers; however, the impact on rates is less when accounting for avoided costs, such as avoided generation, distribution, transmission, capacity, etc.

FIGURE E10: Cost of Incentives for Behind the Meter Programs, Nominal Dollars 2013-2016



Comparing the Costs of Class I Renewable Programs

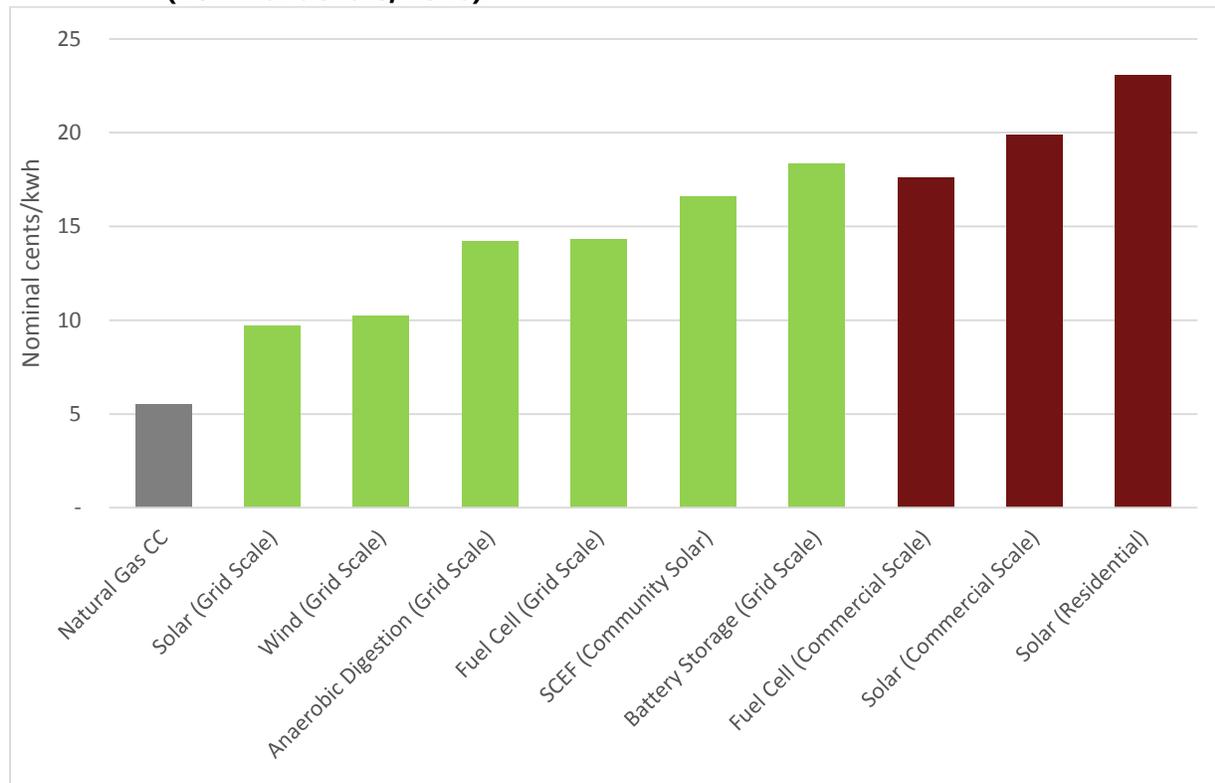
DEEP has compiled pricing information for Connecticut’s behind the meter (i.e. RSIP and LREC/ZREC) and grid scale clean energy programs. The 2016 pricing information in Figure E11 shows the total levelized costs of behind the meter programs presented alongside the total levelized costs of the projects selected in DEEP’s grid scale procurements.³⁹ Grid connected Class I renewable generation technologies are generally less expensive than behind the meter projects and are compensated based on fixed contracts with prices based on the results of a competitive procurement. As shown in Figure E11, in recent procurements grid scale Class I generation costs for wind and solar was less than 10 cents/kWh on a levelized basis over 20 years. Behind the meter

³⁸ The forecasted net metering rates were observed over a 15 year period. However, the forecasted net metering rates under RSIP was observed over a 20 year period.

³⁹ All resources (except Natural Gas CC), are based on the lowest 50 percent of the bid prices submitted in the Large and Small Scale Procurement. Individual prices were adjusted using a weighted average for each generation resource. Fuel Cell (Commercial Scale) and Solar (Commercial Scale) are the projected average gross net metering cost for 2016 thru 2030 plus the corresponding REC price for Year 5 of the LREC/ZREC program.

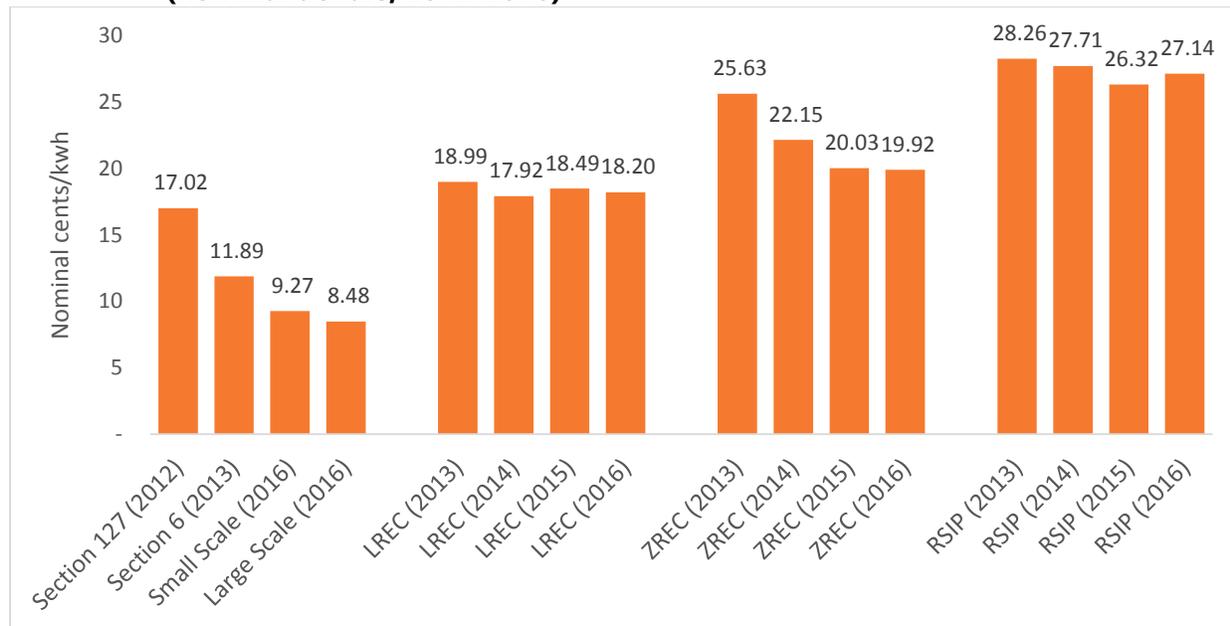
projects, on the other hand, can cost over 20 cents/kWh when both the ZREC/LREC and the cost of net energy billing is considered. The total costs for Class I generation of other technologies (i.e. anaerobic digestion, fuel cell, battery storage) were higher than grid scale solar and wind but still lower than behind the meter programs.

FIGURE E11: Total Levelized Cost of Clean Energy Technologies Compared to Natural Gas (nominal dollars, 2016)



The average cost of renewable deployment across Connecticut programs, administered by DEEP, has declined in the recent years. This decline in cost is most dramatic for grid scale solar and wind projects. In the procurements conducted under Section 127 of Public Act 11-80, DEEP evaluated small grid scale solar projects with a levelized cost of approximately 20 cents/kWh or more. Just five years later the cost of many grid scale solar projects in the Public Act 15-107 procurements were less than 10 cents/kWh in nominal dollars on a levelized basis for the 20 year life of the contracts. The cost of behind the meter projects has also declined, but not to the same extent as grid scale projects. The ZREC/LREC prices have declined, but this is offset by higher retail electric rates. When the cost of net metering is included, the overall reduction for behind the meter programs is not as significant as for grid scale projects.

FIGURE E12: Declining Cost of Clean Energy Programs, Behind the Meter and Grid Side (nominal dollars, 2012-2016)



The results of DEEP’s recent competitive procurements under Public Act 15-107 show that the cost of grid side solar and wind has dramatically declined over the past few years to levelized prices below 10 cents/kWh. The results indicate that grid-connected projects are often much more cost-effective and can deliver the benefits of renewable power at a lower cost to ratepayers than behind the meter projects. The grid scale costs in Figure E12 are the actual prices in long-term contracts to have clean energy delivered into the region on behalf of all Connecticut ratepayers. Small grid side solar and wind in the range of 2MW to 20 MW offered prices similar to much larger grid scale projects. DEEP’s experience with renewable solicitations suggests that an open, competitive and transparent process incentivizes competitive bids and hence drives down the cost of the projects.

Although the behind the meter programs have not seen the declining compensation rates of the grid-connected projects, these programs have several non-price advantages that make investment in these programs worthwhile. Behind the meter programs like LREC/ZREC and RSIP provide many benefits, including but not limited to: (1) helping high energy use customers, like commercial and industrial customers, reduce their grid electric use, thus benefitting the system overall by reducing peak demand; (2) developing clean energy resources that are easier and less controversial to site; (3) providing faster development than grid scale projects; and (4) promoting job growth in Connecticut.

Waste Management Goals and the RPS

Prior to 2017, Class II renewable energy sources included energy derived from resource recovery facilities, biomass facilities that began operation before July 1, 1998 with certain emission levels, and run-of-the-river hydropower up to 5 MW that began operations prior to July 1, 2003. The Class II requirement was initially set at 3 percent and remains constant through 2020. There are currently 123 generating plants across New England that meet the Class II requirement, with a total capacity of 665 MW. More projects could qualify, but do not apply for eligibility because of the low Class II REC prices in Connecticut. The 123 Class II sources include 99 hydropower facilities, 17 resource recovery facilities, and 8 biomass plants. As of 2014, the latest compliance period for the RPS, approximately 857,000 or 89 percent of RECs, used for Class II compliance were produced from generators located in Connecticut.

The supply of Class II resources significantly exceeded the RPS requirements prior to the 2017 legislative session. Given the state's electric demand in 2016, the Class II RPS requirement could be satisfied by approximately 825,000 RECs. This surplus has driven down prices of Class II RECs to less than \$1/MWh. DEEP estimates the cost of Class II RECs to be less than \$1 million in 2016. Due to these very low price of Class II RECs, the revenues provided did very little to support existing Class II facilities or encourage the development of new Class II projects.

Connecticut's five active waste-to-energy facilities provide 144 MW of capacity to the grid, as well as a source of fuel diversity. These waste to energy facilities are an integral part of the state's waste management system, providing over 80 percent of disposal capacity for Connecticut municipal solid waste (MSW). Management of waste via waste-to-energy facilities provides greenhouse gas benefits when compared with landfilling. Maintaining Connecticut's waste-to-energy facilities is necessary until modern waste-conversion processes become viable alternatives.

Connecticut has set an ambitious goal to divert 60 percent of waste from disposal by 2024. Achieving this goal will require both the development of modern waste conversion technologies such as anaerobic digestion, and the installation of advanced sorting equipment at existing waste-to-energy facilities to recover recyclable material from MSW prior to combustion.

DEEP has undertaken an analysis of the waste disposal needs and options in Connecticut as part of the Comprehensive Materials Management Strategy to develop an approach to managing materials that is economically viable and advances the state's economic and environmental goals. DEEP believes that a modest level of support is needed to ensure the continued operation of these facilities that are necessary to meet the state's energy and materials management goals. This support was enacted with the passage of Public Act 17-144, An Act Promoting the Use of Fuel Cells for Electric Distribution System Benefits and Reliability and Amending Various Energy-

Related Programs and Requirements. This bill modifies the Class II eligibility requirements to only include waste to energy facilities that support Connecticut's waste management goals, increases the Class II REC requirement from 3 percent to 4 percent, and changes the ACP to \$25/MWh. This change could result in up to \$27.5 million annually supporting the waste to energy facilities that further our waste management goals.

Biosolids

Similar to the waste to energy sector which integrates the Solid Waste Management planning with the CES energy goals, DEEP also intends to further explore opportunities to integrate biosolids management (sewage sludge) with CES goals. Biosolids are an abundant source of renewable energy. In Connecticut, biosolids are managed through anaerobic digestion and incineration. Either option can be used for distributed electricity generation and/or process & space heating, increasing the energy efficiency of the management facility.

Under current policy, electricity generated using the byproducts from anaerobic digestion of biosolids is eligible for Class I RECS, which provides a revenue stream to incent expanded use of biosolids, which are an abundant source of renewable energy. Additionally, generating electricity by burning the gaseous byproducts of biosolid anaerobic digestion emits less air pollution than incineration. However, there have been few such projects deployed in Connecticut.

The overwhelming majority of biosolids generated in Connecticut are managed through incineration. The state currently depends on five regional (in-state) sludge incineration facilities to meet its current biosolids management needs. The process of incineration generates a significant amount of heat that currently exhausts through smokestacks. If captured and used cost effectively, some of this waste heat could be used for distributed electrical generation, which may create grid reliability benefits for rate payers. In fact, the MDC facility in Hartford generates electricity for use at the plant using waste heat from its biosolids incinerator. Alternatively, the waste heat could be used within the facility or nearby buildings to offset burning fossil fuels for space and process heating, increasing the efficiency of the plant and reducing emissions of air pollution and greenhouse gases from burning fossil fuels.

At present, cost effective management of the state's biosolids relies on operation of the existing incinerators until such time when anaerobic digestion and other means of sludge management mature. In the very near term, the facilities that operate biosolids incinerators will likely need to make significant capital improvements in order to comply with Clean Air Act and Clean Water Act requirements. There may be opportunities, during the implementation of these necessary improvements, to retrofit existing incinerators to generate electricity, process heat, or both. "It is consistent with the goals of this CES to support opportunities to retrofit anaerobic digestion and municipal solid waste incinerators to generate electricity or process heat or both. To advance this

conversation, DEEP intends to hold a technical session with the five regional sewage sludge incinerators.

The Role of Combined Heat and Power and Energy Efficiency in Connecticut’s Class III RPS

Connecticut’s Class III market is comprised of efficiency and energy produced by combined heat and power facilities. The Class III requirement started at 1 percent in 2007, and increased by 1 percent each year until reaching 4 percent in 2010, at which point it remains constant through 2020. Class III RECs have a statutory price floor of 1 cent/kWh and a ceiling of 3.1 cents/kWh, which was implemented in a PURA decision.⁴⁰

Table 6 below shows the Class III requirements and the qualifying Class III RECs between 2007 and 2010. As seen in Table 6, the supply of Class III resources were significantly greater than the requirements. This imbalance resulted in many Class III RECs selling at the price floor of 1 cent/kWh and many not selling at all. DEEP estimated that it cost approximately \$12.8 million to meet the Class III RPS requirement in 2012.⁴¹

Oversupply in the Class III markets resulted largely from continued growth in utility energy efficiency programs, which affected third party conservation efforts. There have been no third party conservation providers selling Class III RECs. Low REC prices also affected CHP units. Prices at the floor level provided little support for existing CHP units and did not encourage new development.

TABLE E6: Summary of Historical Class III Requirement and Qualifying Resource Output⁴²

Year	Class III Supply			Class III Demand (MWh)
	CHP (MWh)	C&LM (MWh)	Total (MWh)	
2007	0	437,854	437,854	338,736
2008	124,331	783,560	907,891	656,600
2009	528,219	1,002,482	1,530,701	951,790
2010	645,978	1,236,626	1,882,604	1,280,838

Source: CLASS III supply as reported in NEPOOL Generation Information System (GIS). Class III demand calculated based on existing RPS targets increasing from 1% in 2007 to 4% by 2010.

The 2013 RPS Study recommended changes to the Class III eligibility requirements by removing conservation funded by Connecticut ratepayers from eligibility.⁴³ In 2013, Public Act 13-303 was

⁴⁰ Conn. Gen. Stat. § 16-243t(a). PURA Docket No. 05-07-19RE02.

⁴¹ IRP p. 18-19.

⁴² IRP p. 18-19.

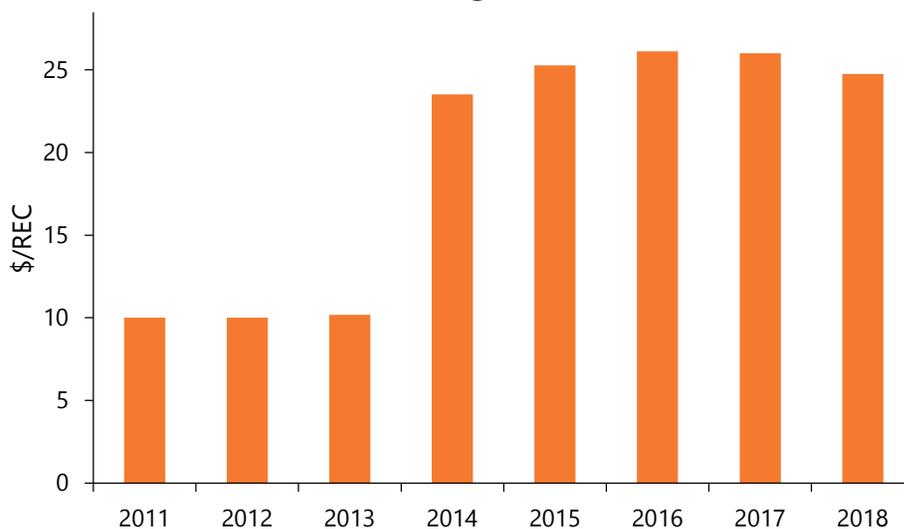
⁴³ DEEP, “Restructuring Connecticut’s Renewable Portfolio Standard” (Apr. 26, 2013).

enacted that changed the eligibility and removed ratepayer funded C&LM from Class III. This change rebalanced the supply and demand for Class III and REC prices increased to approximately \$25 MWH.

The changes enacted in 2013 provided a key incentive for the development of CHP and in 2017 all the Class III REC's were supplied by CHP. DEEP now estimates the cost of Class III to be approximately \$27.5 million in 2017. This could increase slightly in the years ahead if Class III REC prices increase further. Higher Class III REC prices increase revenues for existing CHP units and provide a greater incentive for new CHP and third party conservation development. The total maximum cost of Class III would be approximately \$34.1 million if the entire 4 percent requirement was met at the ceiling price of 3.1 cents/kWh.

Several incentives are currently available to encourage the development of CHP in Connecticut. Behind the meter CHP helps customers reduce their electric costs, heating, and hot water costs. In addition to Class III RECs, CHP is eligible for net energy billing, a waiver on their electric demand ratchets and a discount on natural gas prices. Given these incentives and the higher prices for Class III RECs, DEEP believes that there are adequate incentives in place for CHP at this time.

FIGURE E13: Connecticut Average Class III REC Prices, 2012-2018



Source: SEA analysis, "Renewable Energy 101 Training" slide deck

DEEP will continue to monitor the RPS markets, and if third party conservation and CHP grows to a point where the existing 4 percent requirement is projected to be filled, DEEP will consider

whether the requirement should be increased and present its recommendation to the General Assembly.

Challenging Conditions Nationally for Nuclear Generation

Nuclear power plants operate around the clock as base load generation, which means they have high capacity factors. At the same time, these units cannot ramp up and down, meaning they must be either running at or near full capacity or not at all. These units help diversify the fuel mix as a large non-fossil resource. However, issues remain with regard to security and safety, the short and long-term storage of nuclear waste, and the cost to maintain and operate these facilities, which often have large cooling water intake structures. Nuclear plants have high fixed costs, and relatively low fuel and other variable costs. These plants, like all unregulated generation facilities in New England, must recover their costs from revenues they obtain in the ISO-NE energy, capacity and ancillary service markets or through contracts with electric generation service suppliers. Low natural gas prices make cost recovery more difficult, particularly for high capacity factor units like nuclear because they are dependent on energy market revenues rather than capacity market revenues.⁴⁴ In the near term, nuclear plant daily energy prices are expected to remain low based on forecasted gas prices and additions of more zero marginal cost renewable generation to the system.⁴⁵

As of 2016, the total nuclear generation capacity in New England was 4,196 MW. Connecticut currently has two operational nuclear electric generating units (Millstone Unit 2 and Unit 3) contributing 2,088 MW of summer capacity, approximately 27.6 percent of the State's peak generating capacity. In terms of energy output, the Millstone facility is the largest generating facility in Connecticut and is equal to approximately 50 percent of the power consumed in the state.⁴⁶ In addition to the nuclear power plants in Connecticut, there are two remaining nuclear generation facilities in New England, Seabrook 1 (1,245 MW) and Pilgrim (677 MW), although Pilgrim is scheduled to retire in 2019. Nuclear generation accounted for approximately 12 percent of the generation capacity in New England in 2014 and 34 percent of the energy generated. Electricity generated from nuclear facilities do not emit SO_x, NO_x, or CO₂ and are thus the largest source of emission free electric generation in New England.⁴⁷

⁴⁴ EIA data, available at <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

⁴⁵ EIA Annual Energy Outlook 2017, available at <https://www.eia.gov/outlooks/aeo/>

⁴⁶ Connecticut's demand is about 30 million MWh/yr. Millstone's generation is about 15-16 million MWh/yr.

⁴⁷ Nuclear plants use nuclear fission (a reaction in which uranium atoms split apart) to produce heat, which in turn generates steam, and the steam pressure operates the turbines that spin the generators. Since no step in the process involves combustion (burning), nuclear plants produce electricity with zero air emissions. Pollutants emitted by fossil-fueled plants are avoided, such as sulfur dioxide (SO_x), nitrogen oxides (NO_x), mercury, and carbon monoxide. (SO_x and

Nationally, the low cost of natural gas is a primary contributor to nuclear plant retirements before the end of their useful lives.⁴⁸ This trend has called into question the economic viability of the remaining nuclear units. DEEP has not seen any evidence of an imminent retirement; both Millstone units cleared the most recent ISO-NE forward capacity auction (FCA 11), obligating them to operate through May 31, 2021 or find other generators to take on their obligation. Additionally, Millstone did not submit a retirement or delist bid for either unit in advance of FCA 12, which it would have had to do by March 24, 2017 if it were considering retiring either unit before May 31, 2022. Estimating a plant's going forward costs and profitability is difficult in a deregulated market if plant owners choose not to disclose it, since that type of information is not ordinarily available to state regulators.

Early retirement of Millstone Units 2 and 3 – i.e., well before their license dates of 2035 and 2045 respectively – would result in a considerable loss of generation capacity in Connecticut. The ISO-NE capacity market - if it operates as planned and capacity prices are high enough to attract sufficient capital investment to build new generation - would deliver new generation to replace Millstone. However, that replacement generation would likely be natural gas fired generation without firm fuel supply. Building 2,000 MW of new natural gas capacity on an expedited timeframe to replace a Millstone's output would drive up capacity and energy prices, resulting in higher electric rates in Connecticut. The replacement of nuclear with natural gas also would reduce regional fuel diversity, and materially exacerbate the winter reliability problem. Additionally, New England's electricity sector CO₂ emissions would increase by an estimated 8 million tons per year or approximately 27 percent in annual emissions. Increasing GHG emissions resulting from the early retirement of Milestone and its replacement by natural gas would make compliance with Connecticut's GWSA carbon reduction mandates more challenging, and increase the costs of CO₂ allowances in the RGGI market.

Millstone's 2,000 MW would not be immediately replaceable with regional or in-state Class I renewable generation. As a practical matter, it would take years to develop and site in-state or out-of-state clean energy resources. To replace Millstone's 2,000 MW at a 90% capacity factor would require approximately 1,500 wind generators that are 3.5 MW each, or 12,000 MW of solar, which translates to approximately 30,000-60,000 acres at grid scale (over 2 MW), or 2 million homes with average sized rooftop systems. These renewable systems would likely require significant energy storage or quick starting gas generation to help balance the resource's variability.

NO_x contribute to acid rain and smog.) Nuclear plants also do not emit carbon dioxide (CO₂), which is a significant advantage in the effort to curb greenhouse gas emissions.

⁴⁸ In 2014, the 619 MW Vermont Yankee facility was retired and the 677 MW Pilgrim facility will retire in 2019.

Customer Bills Show Generation Rates Declining, but Other Components Increasing

Connecticut's per capita electricity use is among the lowest in the nation according to Energy Information Administration (EIA). As a result, Connecticut ranked 27 in overall average electric bills in 2014 compared to other states, despite having high retail electricity rates.⁴⁹ Demand for air conditioning is small during the relatively mild summer months, and fewer than one in six Connecticut households use electricity as a primary source for home heating in winter. The American Council for an Energy Efficient Economy (ACEEE) ranked Connecticut fifth nationally in 2016 recognizing the strength of Connecticut's energy efficiency programs.⁵⁰ These mature programs have been instrumental in reducing electricity use and peak demand, and in turn, have helped consumers reduce power bills.

Although Connecticut electric bills are in the middle nationally, electric rates in Connecticut are among the highest in the nation. Connecticut ranked around 45th highest for most of the 1980's and 1990's and in February 2017, Connecticut ranked 49th highest out of 51 (50 states plus the District of Columbia) in average overall retail electric rates at 17.44 cents/kWh.⁵¹ The average in Connecticut was approximately 70 percent above the national average price of 10.33 cents/kWh. The only states with higher electric rates were Alaska and Hawaii. Excluding Alaska and Hawaii, the states with the highest electric rates are in the Northeast, Middle Atlantic and California.⁵² While the rankings change somewhat over time, states in the Northeast and Middle Atlantic are consistently among the highest rates, while the South and Pacific Northwest are the lowest.⁵³

⁴⁹ EIA Table E18 Coal and Retail Electricity Price and Expenditures Estimates, Ranked by State 2014.

⁵⁰ <http://aceee.org/state-policy/scorecard>

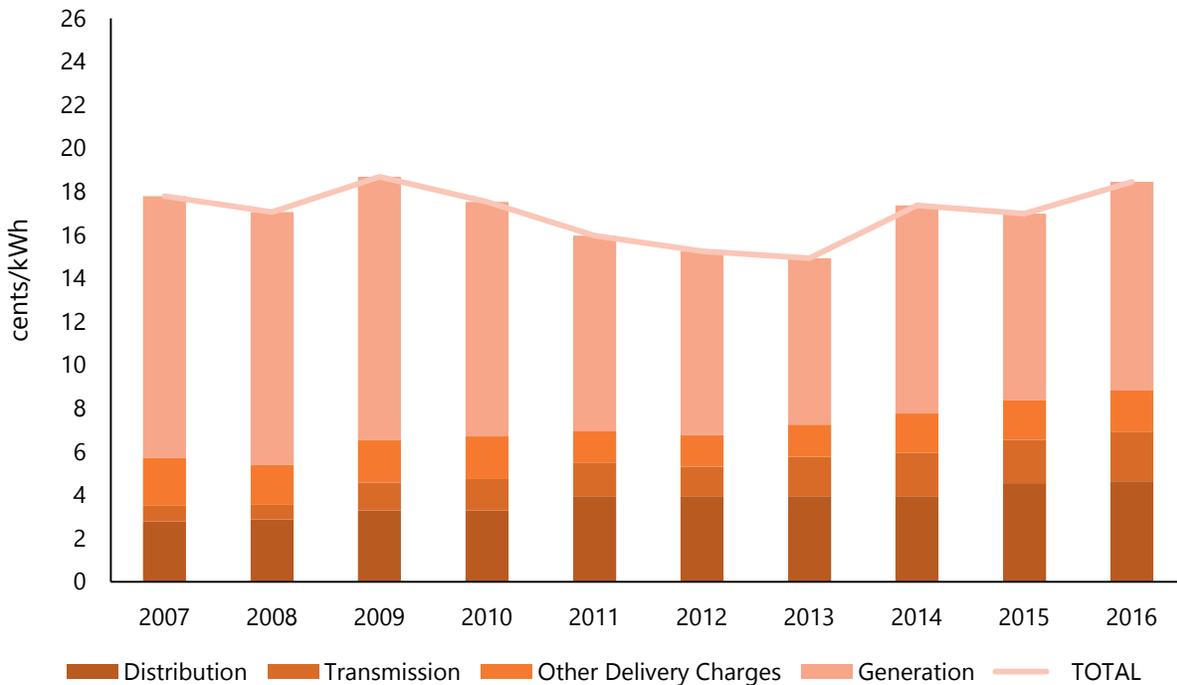
⁵¹ U.S. EIA Table 5.6.A Prices of Electricity to Ultimate Customers by End use Sector, by State Feb 2017 and 2016.

⁵² U.S. EIA State Energy Profiles.

⁵³ EIA Electric Power Monthly, November 2015.

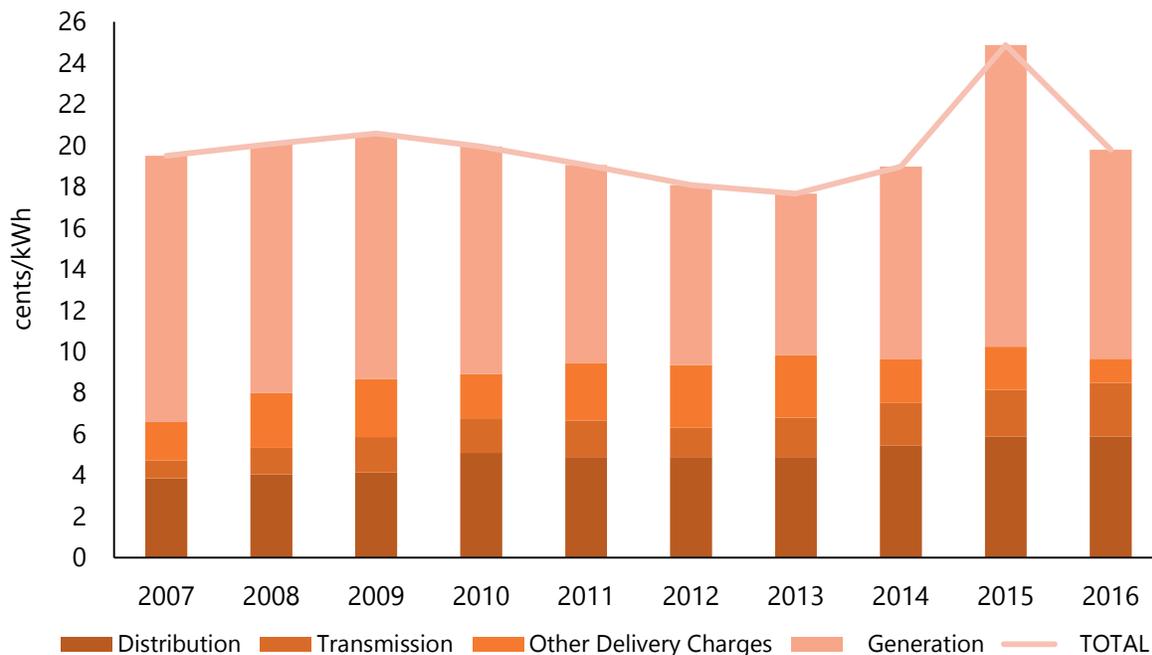
In 2000, Connecticut’s average electric rates for all sectors was 13.4 cents/kWh, which ranked 42nd, approximately 32 percent above the national average of 10.2 cents/kWh (2016\$). From 2000 to 2009, electric rates rose by approximately 50 percent to 20.2 cents/kWh (2016\$), 84 percent higher than the national average of 10.98 cents/kWh (2016\$). Due to higher than average rate increases relative to other states, Connecticut’s overall ranking dropped to 49th.

FIGURE E14: Eversource Average Electric Rates 2007-Present



Since reaching a peak in 2009, electric rates in Connecticut have declined each year from 2009 through 2013 due to lower generation rates driven by lower natural gas prices, the elimination of stranded costs (a legacy of deregulation), and major investments in new generation and

FIGURE E15: UI Average Electric Rates 2007-Present



transmission that reduced capacity and energy prices. Since 2013, electric rates have increased, returning to the levels reached in 2009.

Generation Rates

Generation is one of the largest component of rates, representing just over 50 percent of the total electric rate, followed by distribution and transmission. Before electric restructuring, PURA regulated generation rates based on the cost of service to generate power. With restructuring, the competitive market – and the design of that market – determine and influence generation service rates. Customers may purchase generation service from competitive suppliers or from Eversource/UI under the Standard Service offer. In this system, the price of electricity in Connecticut is highly correlated with the price of natural gas. Eversource’s average generation rates for standard/default service have increased from 4.81 cents/kWh in 2000 to a high of 12.1 cents/kWh in 2009. Generation rates then declined in 2010, 2011, 2012 and 2013 before increasing again due to high natural gas costs in the winter. Average generation rates were 9.64 cents/kWh in January 2016 or an increase of 100 percent since 2000. UI’s standard/default service generation rates followed a similar pattern. UI’s average generation rates across all customer classes have increased by 120 percent from 4.63 cents/kwh in 2000 to 10.14 cents/kWh in 2016.

While the generation rate has increased by over 100 percent since 2000, the total cost of generation has not gone up as much as the generation rate increase indicates. Before restructuring, the generation rate was approximately 6.00 cents/kWh. When restructuring began,

some of the generation costs were considered stranded costs and were collected in the Competitive Transition Assessment (CTA) charge, resulting in a portion of the 6.00 cents/kWh generation rate being allocated to the CTA charge. For UI the CTA was 1.49 cents/kWh in 2000. Adding the CTA to the new generation rate of 4.63, the total average cost of generation in 2000 was 6.12 cents/kWh for UI. The CTA for Eversource was 1.02 cents/kWh in 2000 resulting in a total average generation cost of 5.83 cents/kWh.

Competitive Generation Supply

Because of electric restructuring in Connecticut, electric generation services are provided to Connecticut's customers either by the default or Standard Service provided by the state's two EDCs, Eversource and UI, or service by competitive electric suppliers. Section 16-244b of the General Statutes authorized electric customers to choose their own electric suppliers in a competitive generation market, starting July 1, 2000. PURA maintains an official Rate Board on the EnergizeCT website that displays the supplier names, product prices and other features of their products,⁵⁴ which allows for "comparison shopping" when a customer is considering switching to competitive generation. PURA also oversees a Supplier Working Group, which includes suppliers, aggregators, EDCs, and representatives of the Office of Consumer Counsel (OCC). This group was established to address, in a collaborative manner, improvements to the Rate Board and any other particular concerns as they arise.

Nearly all of the state's largest commercial and industrial (C&I) customers purchase their electric power from competitive electric suppliers. A portion of small C&I customers (maximum peak use up to 500 kW) and residential customers have migrated to alternative retail suppliers, but many remain on Connecticut's default service.

Transmission Rates

While the generation portion of rates have declined in recent years after reaching a peak in 2009, the distribution and transmission charges have steadily increased. Transmission rates recover the cost of the transmission infrastructure used to move electricity from power plants to local distribution systems. Prior to restructuring, PURA regulated and set the transmission rates for Eversource and UI. Because of restructuring, FERC now regulates and ISO-NE administers transmission. Investments to improve system reliability and reduce congestion have translated into rapidly rising regional transmission costs known as the Regional Network Service Rate (RNS Rate). FERC regulatory actions have also contributed to the rise in transmission rates by allowing

⁵⁴ <http://www.energizect.com/compare-energy-suppliers/compare-supplier-options>

high rates of return and bonus incentives on transmission investments. Many projects have also been significantly over budget but have still received full cost recovery under FERC jurisdiction.

In addition, some transmission costs are for local transmission facilities that are not considered part of the regional network. This is called Local Network Service (LNS) Rate. The RNS and LNS rates are combined to form the transmission rate charged to customers.

Since 2000, Eversource's transmission rates have risen 500 percent from 0.38 cents/kWh to 2.29 cents/kWh in January 2016. UI's transmission rates have risen 250 percent since 2000 from .75 cents/kWh to 2.60 cents/kWh to fund major infrastructure investments to improve system reliability and reduce congestion. Reducing congestion has enabled lower cost generation to move more freely from generation to load centers in Connecticut, which has contributed to lower generation rates (offsetting a portion of the transmission rate increase). Congestion charges, which are recovered through the bypassable federally mandated congestion charge (BFMCC) component of generation rates, declined from over 1.11 cents/kWh for UI in 2006 to negative 6 cents/kWh today, resulting in a credit on customer bills.

A number of projects are currently underway or in the planning stages to improve system reliability in Connecticut and the rest of New England. There will also likely be an increased need to invest in transmission infrastructure in the years ahead to expand transmission to move renewable power generated in remote locations to population centers in Connecticut and southern New England to reach our RPS and GWSA goals.

Distribution Rates

Distribution costs for both UI and Eversource have increased over the years to recover higher costs of doing business such as rising payroll costs and associated benefits, and the capital cost associated with the replacement of aging distribution system components and improvements to modernize and harden the system to withstand storms. Eversource's distribution rates have increased 82 percent from 2.55 cents/kWh in 2000 to 4.64 cents/kWh in 2016. UI distribution rates have increased by 107 percent from 3.27 cents/kWh to 6.76 cents/kWh. UI's distribution rates are higher than Eversource's because UI has a more urban service territory and therefore more of its distribution facilities are underground. An underground distribution system is more expensive but improves reliability. Grid modernization, strategies to utilize smart devices and appliances to reduce peak demands, and planning efforts to strategically locate distributed generation may help to offset future distribution and transmission cost increases.

Future Trends in Generation, Transmission and Distribution Costs

The energy component of generation rates is not expected to rise significantly if low natural gas prices continue. The biggest risk is during cold winter months when gas pipelines are most constrained because customers increasingly use natural gas for home heating and therefore there is less excess capacity available for electric generators that purchase gas in the spot market. In addition, the need to replace and improve distribution and transmission infrastructure will continue, which must be recovered. Significant increases in renewable generation will be critical to achieving Connecticut's greenhouse gas (GHG) emissions reduction goals of an 80 percent reduction below 2001 levels by 2050 under Connecticut's Global Warming Solutions Act (GWSA).⁵⁵

High electric rates create challenges for Connecticut customers to pay their electric bills and businesses to remain competitive. PURA provides regulatory oversight to keep rates as low as possible, while allowing the utilities to recover their costs and make a reasonable return so they can provide clean, safe, and reliable service. DEEP and PURA will continue to work with ISO-NE to ensure that the ISO-NE markets provide proper incentives to generators to ensure reliable service at reasonable costs to Connecticut electric customers. DEEP has developed specific strategies to assist customers in reducing their electric bills, such as energy efficiency, alternative rate options and demand response programs. In addition, DEEP's focus on mechanisms to minimize the impact on electric rates is reflected in the strategies recommended to increase renewable generation to meet our environmental goals at the lowest cost to ratepayers in the years ahead, particularly Strategies 3 and 4.

Additionally, DEEP has emphasized the importance of limiting the costs collected through the fixed customer charge to only those costs directly related to the customer in recent rate cases from Eversource and UI. Section 16-243bb of the General Statutes requires PURA to "adjust each electric distribution company's residential fixed charge upon such company's filing with the authority an amendment of rate schedules pursuant to section 16-19 to recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service." Through PURA Docket No. 17-01-12, *PURA Establishment of a Maximum Residential Customer Charge (MRCC) Formula for Non-Electric Heating Residential Service*, PURA is establishing a protocol for the EDCs to follow going forward in allocating costs that can be collected through the fixed charge.

⁵⁵ CGS 22a-200(a).

Resource adequacy and distribution reliability are strong, while natural gas dependence can pose winter reliability risks

Generation Reliability

Resource Adequacy

ISO-NE is charged with ensuring resource adequacy for the region. Resource adequacy in its simplest definition is the condition in which, taking into account transmission constraints, the electric system has enough generation resources to meet electric demand in New England reliably under reasonably anticipated circumstances. This means that the ISO must have enough generation available during the highest expected demand periods. To ensure there are enough generation resources during peak periods, the ISO instituted a Forward Capacity Market (FCM). Generators that participate in the FCM take on what is called a Capacity Supply Obligation (CSO), an agreement by the generator to produce a certain amount of electricity if called upon by the ISO. The FCM is designed to provide generators with the “missing money” that they need but are not able to collect in the energy and ancillary markets to ensure adequate supply.

The FCM is operated through a Forward Capacity Auction (FCA) three and a half years in advance of the CSO. ISO-NE conducts the FCA through a descending clock auction where the price offered continues to decline until only enough resources remain in the auction. The FCM is designed so that if a new resource is needed, to meet growing peak demand or to replace a retiring generator, the clearing price will be sufficient to support the financing of the new resource. The FCA does not distinguish between resource types. Accordingly, the resources that offer the lowest prices clear the market.

The ISO has conducted eleven FCAs that have successfully attracted and retained sufficient resources to meet resource requirements. However, all the significant new generation resources have been natural gas fired. Between 2012 and 2020, more than 4,200 MWs of non-natural gas fired generation will retire.⁵⁶ The bulk of those MWs were replaced in the FCAs by natural gas fired generation.⁵⁷ The remaining coal, oil, and nuclear units are considered at risk of retirement.⁵⁸ This presents a significant reliability concern for the region as the region becomes so heavily reliant upon natural gas generation without the necessary natural gas transportation infrastructure.

⁵⁶ ISO-NE 2017 Regional Energy Outlook p. 27 available at https://www.iso-ne.com/static-assets/documents/2017/02/2017_reo.pdf

⁵⁷ *Id.*

⁵⁸ *Id.*

As of FCA 11, within the FCA for New England as a whole there are three sub-regions (Northern New England, Southeast New England, and Rest of Pool) that have Local Sourcing Requirements (LSR) to ensure that transmission constraints do not leave any part of the system with insufficient generation to meet peak load conditions.⁵⁹ For the past two FCAs, after recent upgrades to the transmission system and new resources recently constructed or expected to be constructed, Connecticut had sufficient local resources not to necessitate its own zone. Because the FCA is conducted three and a half years in advance of when the capacity is needed, Connecticut has enough capacity through June 2021. Absent the retirement of more than 2,000 MWs of supply, there is no expectation that Connecticut will have insufficient local resources for the foreseeable future.

Natural Gas Dependence

In New England, natural gas fired generation is the marginal unit – i.e., the unit turned on to meet the next increment of electric demand – approximately 75 percent of the time.⁶⁰ Although the competitive energy markets incentivize the development of low cost resources, the markets do not sufficiently incentivize the availability of fuel sources. Generally, gas generators do not purchase long-term firm capacity contracts for gas supply because the costs of doing so for any one generator are very high and will make the unit uncompetitive. Instead, generators rely on excess capacity in the gas transmission system and purchase gas on the spot market. Accordingly, as the market incentivizes more and more natural gas generation, the infrastructure to deliver natural gas has not kept up and the system becomes constrained during peak demand for natural gas for heating uses, creating a winter price and reliability problem.

When gas is constrained, the system relies on existing coal and oil generation units to supply the region's electricity needs.⁶¹ This makes it difficult to operate the system cleanly and reliably. Many of these units are old, less reliable and are not designed to operate as peaking units. These older units were originally base load units and do not have the ability to be turned on quickly or ramp up and down to meet rising and falling loads. Many of these older non-gas units are retiring or are at risk of retirement. The market, as designed, is replacing the retiring units with more natural gas generation, exacerbating the risks as the demand for gas rises and the available capacity remains relatively constant. This occurs because the markets are "fuel neutral" and natural gas units are generally the least expensive units to build and operate. It should be noted, however, that modern natural gas units tend to be flexible, meaning they start up on short notice and can

⁵⁹ The ISO models transmission constraints before determining the appropriate subzones in each FCA.

⁶⁰ See ISO-NE Key Grid and market Stats available at <https://www.iso-ne.com/about/key-stats>

⁶¹ See ISO-NE State of the Grid: 2017, Slide 17, available at https://www.iso-ne.com/static-assets/documents/2017/01/20170130_stateofgrid2017_remarks_pr.pdf

ramp up and down quickly. This flexibility is an important support to more variable resources and is increasingly important as more renewable resources come onto the system.

ISO-NE Winter Reliability Program

To address potential reliability problems due to natural gas supply constraints for the winter 2015/2016 and 2017/2018, the ISO-NE instituted a “winter reliability program” designed to ensure that enough generation is available on the coldest days of the winter when the natural gas distribution system is heavily constrained and there is less gas available for generation. The program pays oil generators to maintain enough fuel on site to operate for 10 days, and pays natural gas generators to contract for liquefied natural gas (LNG) to operate for four days, and pays demand response resources to be available for up to 180 hours beyond their obligations in the forward capacity market. After the 2017/2018 winter, the ISO’s Pay for Performance (PfP) FCM construct is intended to ensure reliability. Simply stated, PfP is a market mechanism designed to compensate generators for operating when most needed and penalize generators if they do not operate when called upon. The intent of PfP was to encourage new gas generators to invest in equipment necessary for dual fuel capability so that they would have the ability to also burn oil during times of gas constraints. However, environmental concerns (both from air quality and water use perspectives) restrict the operational capability that new dual fuel (natural gas and oil) units are permitted to operate using oil. PfP also encourages the retirement of the older oil and coal units that are exposed to the punitive aspect of PfP because of their inability to ramp-up quickly. Despite the institution of PfP, ISO-NE remains concerned that the system remains overly reliant on natural gas generation without a clear pathway to relieve the constraints on fuel availability.

Natural Gas RFP

In recognition of the risks posed by the lack of natural gas infrastructure and increased usage of natural gas for electric generation, the Connecticut General Assembly enacted Public Act 15-107. This legislation was enacted in response to the 2014 IRP that recognized that while the electric reliability issues are caused by constrained natural gas pipelines in the winter, the solution can be broader than just natural gas pipeline expansion and can include the deployment of clean and renewable energy resources. Thus, the legislation authorizes the DEEP Commissioner to solicit bids for up to 350 MMCF natural gas capacity and clean energy resources to meet winter reliability needs and allows the recovery of costs from electric ratepayers. The 350 MMCF is the approximate equivalent of Connecticut’s share of the anticipated natural gas capacity deficit that is necessary to relieve the constraints during the winter peak periods.

DEEP released an RFP on June 2, 2016 seeking bids for natural gas capacity. Bids were received for gas pipelines and liquefied natural gas proposals. However, while this evaluation was underway, the Massachusetts Supreme Judicial Court denied Massachusetts’ EDCs the authority

to get cost-recovery from electric ratepayers for costs associated with the development of natural gas pipelines. This court decision along with regulatory proceedings in other New England jurisdictions materially reduced the ability for other states to procure gas resources and help share the costs. Cost sharing is critical due to the scale and cost of these natural gas pipeline projects. The problem of inadequate gas infrastructure is greater than one state can solve alone. Regional investment is necessary to ensure that no one state disproportionately bears the costs of addressing what is a problem endemic to our regional electric system. Thus, without a path forward for regional investment, DEEP issued a notice of cancellation of the RFP on October 25, 2016.

While the natural gas RFP was cancelled, DEEP continued with its procurement of clean energy resources pursuant to Sections 1(b) and 1(c) of Public Act 15-107. In 2016, DEEP selected solar and wind projects located in Connecticut and the New England region to enter into contracts with the EDCs to meet approximately 4.5% of our load. These clean energy projects will be coming online over the next few years and should help alleviate some of our reliability risks.

Transmission Reliability

From 2004 through 2008, ISO-NE and southern New England stakeholders identified a number of limitations with the west-east movement of power throughout New England, and weaknesses in the transmission system that threatened electric power reliability in Connecticut and southern New England in a study known as the Southern New England Transmission Reliability (SNTR). In response to the study, beginning in 2009, a group of related transmission projects, known as the New England East-West Solution (NEEWS), were undertaken. The final project, the Interstate Reliability Project, was completed in December 2015 with the addition of a high-voltage transmission line and upgraded substations in Connecticut, Massachusetts, and Rhode Island. With the completion of the NEEWS transmission projects, regional transmission bottlenecks significantly affecting Connecticut were removed.

ISO-NE is currently assessing the need for new transmission facilities to move renewable power from remote areas in Northern Maine to load centers in southern New England. Such projects will be expensive and therefore will require a regional approach if we are to expand renewable generation significantly in the years ahead.

Distribution Reliability

Many of the regulatory and legislative proceedings that have occurred over the last several years have focused on utility resiliency to make utility company infrastructure more resilient to storm damage, and to promote shorter restoration times following outages from weather-related events. Many of the recommendations from the 2011 Two Storm Report have been implemented,

and have improved the EDCs preparedness and response time, most notably with Super Storm Sandy in 2012 and subsequent weather-related outage events in the past few years. Other initiatives, including utility system hardening, reinforcement of substations and investment in distribution lines continues to advance.

EDCs vegetation management plans were expanded and the budgets were significantly increased as a result of the 2011 and 2012 storms. As shown in Table E6, the Eversource tree trimming budget increased by 50 percent from \$26 million in 2011 to \$39.5 million in 2015. The UI budget has more than tripled from approximately \$4 million in 2011 to nearly \$15 million in 2015.⁶² The changes in utilities' Vegetation Management Practices are the result of regulatory and stakeholder proceedings to establish best practices that incorporate an environmental perspective which are more sensitive to the needs and wants of the affected local communities in which the work is proceeding.

TABLE E7: EDC Vegetation Management Budgets⁶³

Year	Eversource	UI
2011	\$26M	\$4.3M
2012	\$50.8M	\$5M
2013	\$29.5M	\$5.5M
2014	\$34.1M	\$9M
2015	\$39.5M	\$15M

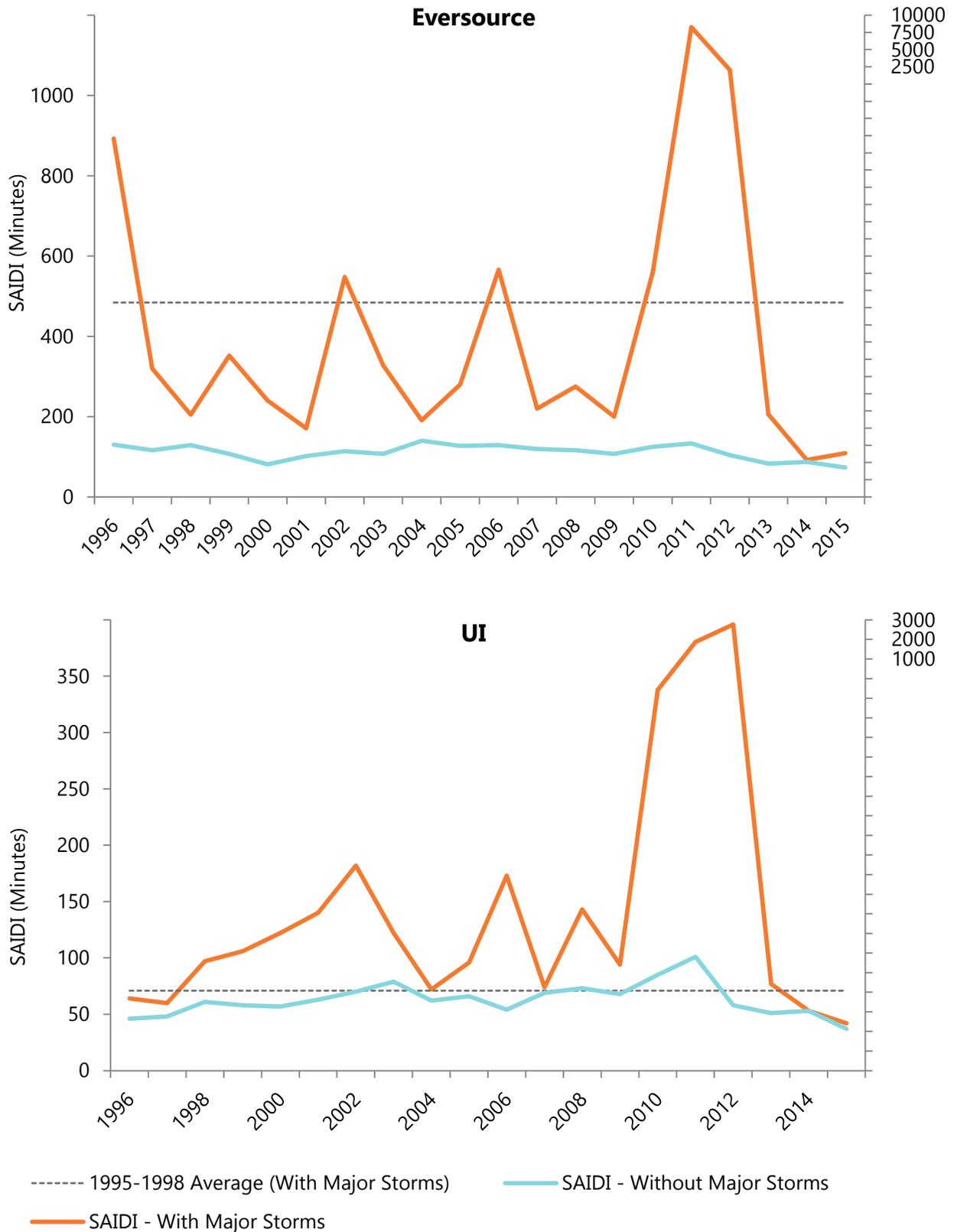
Section 16-245y(a) of the General Statutes requires PURA to submit reliability data, in terms of the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), to the General Assembly by January 1 of each year.⁶⁴

⁶² Decision dated June 30, 2010, in Docket No. 09-12-05, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules; Decision dated August 14, 2013, in Docket No. 13-01-19, Application of The United Illuminating Company to Increase Rates and Charges.

⁶³ PURA Docket No. 86-12-03, *DPUC Investigation of the Connecticut Light and Power Company and The United Illuminating Company Excessive Outages – Long Range Investigation re Adequacy*.

⁶⁴ SAIDI is defined as the sum of customer interruptions in the preceding 12-month period, in minutes, divided by the average number of customers served during that period. Conn. Gen. Stat. §16-245y(a). SAIFI is defined as the total number of customers interrupted in the prior 12-month period divided by the average number of customers served during this period. *Id.* SAIDI can be viewed as the average outage duration experienced by all customers on an electric distribution company's system (EDC's), and SAIFI can be viewed as the average outage frequency on an EDC's system. Lower SAIDI and SAIFI numbers reflect better reliability performance in terms of outage duration and frequency, respectively.

FIGURE E16: Eversource and UI SAIDI Results



The 2016 report to the legislature indicates that UI and Eversource are performing well. Reliability has improved over the past few years since the major storms of 2011 and 2012. Eversource has performed significantly better than the averages from 1995-1998 just prior to electric restructuring. UI generally has higher reliability than Eversource. Much more of UI's distribution system is underground compared to Eversource that has more rural customers fed by miles of overhead lines that are more susceptible to outages due to vegetation such as falling trees and branches.

Microgrids

The Microgrid Program was developed in 2012 in response to the recommendation of the Governor's Two Storm Panel regarding the use of microgrids to minimize the impacts to critical infrastructure associated with emergencies, natural disasters, and other events when these cause the larger electricity grid to lose power. Microgrids provide electricity to critical facilities and town centers on a 24/7 basis and will include an isolation system so the microgrid can provide power despite any large-scale outages and support critical facilities.⁶⁵

DEEP conducted two competitive solicitations for microgrid projects and awarded \$20.1 million in grants to ten projects.⁶⁶ On November 5, 2015, DEEP initiated the third round of the Microgrid Program by issuing a request for applications.⁶⁷ DEEP accepted applications from December 10, 2015 through August 31, 2017. DEEP received four applications. DEEP awarded one grant and rejected three applications.

A variety of critical facilities are being supported including municipal facilities such as police and fire stations, dorms and schools for shelters and private facilities such as a grocery store, gas station and senior housing. To date, six projects are operational and the remaining projects are in various stages of development. Microgrid projects are being developed along the shoreline from Fairfield to Milford and through interior Connecticut from Woodbridge to Windham. The towns with microgrids are highlighted on the map below.

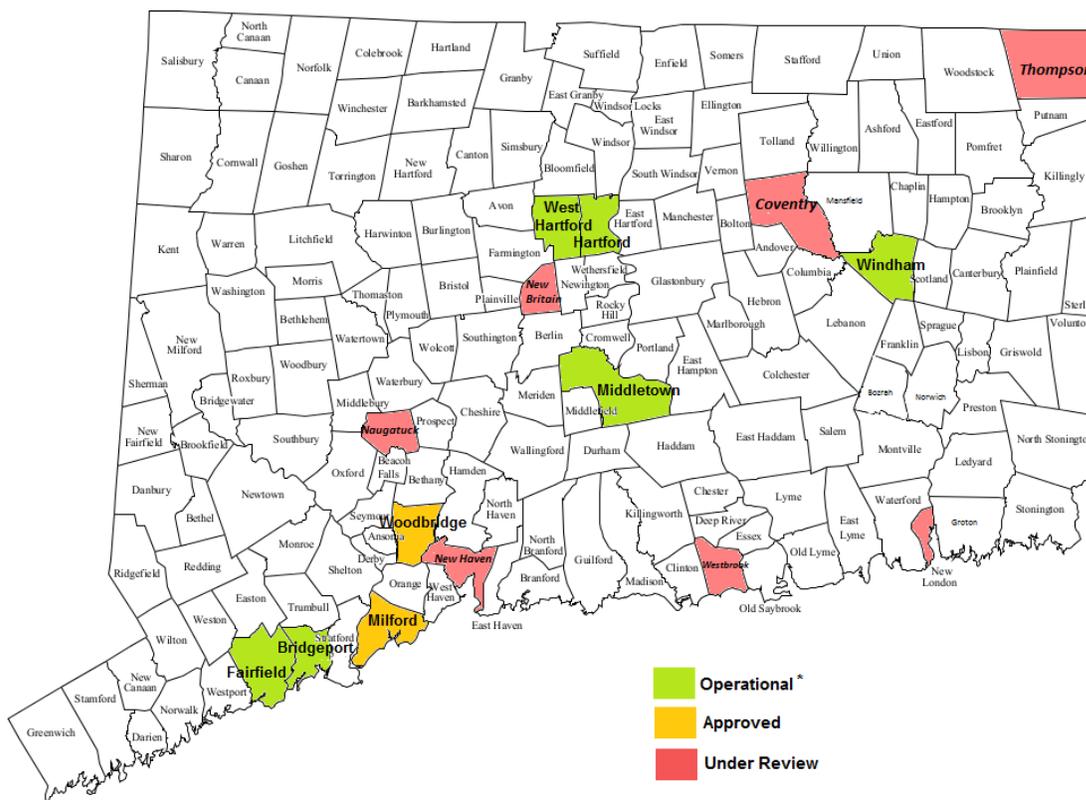
⁶⁵ Connecticut General Statutes, Section 16-243y, as modified by Public Act 13-298, Section 34.

⁶⁶ The maximum grant paid to any one project is \$3 million.

⁶⁷ Link to the request for applications on DEEP's website:

<http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/69dc4ebaa1ebe96285257ed70064d53c?OpenDocument>.

FIGURE E17: Connecticut Microgrid Projects⁶⁸



**Bridgeport and Middletown both have 2 projects in each town. In each town, one project is operational and the other is approved but not yet operational. Middletown and Hartford also have one project under review in each town..*

Public Act 16-196 authorized DEEP to provide matching funds or low interest loans through the microgrid program for energy storage systems or Class I or Class III generation sources provided such projects are first placed in service on or after July 1, 2016. DEEP released the round four request for applications to implement the matching funds or low interest loan option in August 2017 and accepted applications from September 1, 2017 through January 1, 2018. Nine applications were received and are currently under review. The towns with microgrid applications under review are highlighted on the map above.

The addition of generation for microgrids could benefit the system by delaying the upgrade of a substation or distribution lines. Microgrids could also aid in frequency regulation and volt ampere reactive (VAR) support, i.e. provide reactive power to maintain transmission voltages to meet the

⁶⁸ Bridgeport and Middletown each have one operational and one approved project within the town boundaries; all other towns have only one microgrid project in each town.

operating requirements for the New England Transmission System. DEEP encourages the EDCs and MEUs to study the best locations for where microgrids could provide those services.

Coastal Resiliency Within ISO-NE

Connecticut's coastal towns have experienced power disruptions and damage by flooding and storm surge during extreme precipitation events and hurricanes. Flooding near substations has already been a serious problem for UI and it will likely get worse in the future. Rising sea level due to global climate change represents a clear and present danger to the UI transmission system. The threat was crystalized by weather events such as Tropical Storm Irene and Superstorm Sandy along with revisions to Federal Emergency Management Agency (FEMA) flood maps.⁶⁹ In response to these events, UI evaluated the risk and potential impact of a single 100-year coastal flooding event on its seven coastal substations.⁷⁰ The 2017 UI study concluded that although all seven UI substations complied with design codes and generally accepted industry flood protection levels when they were originally built, they are now considered deficient when compared to FEMA's significantly revised flood elevations (updated in 2013). According to the study, five of the seven UI coastal substations built adjacent to Long Island Sound are "at-risk" of being destroyed by a FEMA 100-year flood event and could result in a significant and sustained adverse impact to the New England Bulk Electric System (BES) and Connecticut customers.

Much of the physical plant and equipment at UI's at risk coastal sub stations are considered transmission and therefore improvements should be eligible for regional cost sharing through transmission rates. UI is seeking cost recovery through ISO-NE, which is responsible for the transmission system. There are not set procedures to determine which costs relating to necessary upgrades for climate adaptation are eligible for recovery. DEEP will work with PURA, UI, ISO-NE, and the other New England states and stakeholders to develop procedures and so that work can begin on these important improvements to ensure reliability in Connecticut's coastal communities. UI has presented to the ISO-NE Planning and Advisory Committee its proposed solutions to the at-risk coastal substations. Significantly, UI is working with state and local partners to leverage a United States Department of Housing and Urban Development resiliency grant to include protection of one of the at risk substations.

⁶⁹ Tropical Storm Irene affected the North East Coastline including UI service territory on August 28, 2011. Superstorm Sandy affected the North East Coastline including UI service territory on October 29 2012.

⁷⁰ The 100-year flood has 1 percent risk of happening in any given year, but presents a cumulative risk of occurring over the life of a give an asset.

Energy Assurance

In 2012, Connecticut developed an Energy Assurance Plan (EAP) for the state.⁷¹ The EAP describes the state's ongoing efforts towards enhancing energy assurance and securing its energy future. The response framework identified in the EAP will help the State prepare for, respond to, recover from, and mitigate the effects of future man-made or natural energy supply disruption events.

The EAP's structure is influenced by the four phases of emergency management – preparedness, response, recovery, and mitigation. Connecticut has undertaken a broad array of activities to promote energy assurance throughout all four phases of emergency management. The Department of Emergency Management and Public Protection continues to advance emergency management improvements, such as, creating a state-level All-Hazards Energy and Utilities Plan (ESF-12) as an annex to the State Response Framework (SRF) and improving communications between local and state government and utilities during emergencies.⁷²

DEEP continues to advance energy system improvements, such as applying stricter performance standards for vegetation management increasing RPS goals, and deploying microgrids to support implementation of the EAP. The EAP's purpose of enhancing energy resiliency, reliability, and emergency response aligns with the state goals of promoting cheaper, cleaner, and more reliable energy. In addition to the State's commitment to improving the reliability of its energy supply system, efforts are ongoing to improve energy emergency management capabilities and working collaboratively across state government. Regular and ongoing statewide efforts continue on coordination and implementation of the SRF and ESF-12 to prevent energy supply disruptions and to implement recovery protocols to minimize recovery times in the event of an energy supply disruption.

Grid Modernization is Progressing, But More Should be Done

Grid modernization can be a critical component of safety and reliability of the grid, in addition to potentially reducing transmission and distribution costs for electric customers and integrating advanced technologies and distributed resources. The structure of the electric system is evolving, and the roles of the state's EDCs, generators, PURA, ISO-NE, and customers are also changing. With this evolution, there are opportunities to explore potential cost savings. The traditional utility model – one in which electricity is centrally generated, transmitted over high voltage power lines,

⁷¹ DEEP, Energy Assurance Plan for Connecticut, Final Draft (Aug. 2012).

⁷² Department of Emergency Services and Public Protection, State of Connecticut State Response Framework (Sept. 2014).

stepped down in voltage, and locally distributed to customers – is facing a new set of challenges and opportunities that could initiate a period of innovation and modernization.

Grid modernization uses communication technologies and infrastructure improvements to make the electric grid more secure, efficient, and reliable. Modernization will enable more effectively integrate distributed energy resources, demand side and renewable resources, and “smart” (real-time, automated, interactive) technologies for metering and communications regarding grid operations and status. Grid modernization includes the deployment and integration of advanced electricity storage and peak-shaving technologies, development of standards for communication and interoperability of appliances and equipment connected to and infrastructure serving the electric grid, and the identification and reduction of barriers to the adoption of smart grid technologies, practices, and services.⁷³ On the federal level, U.S. Department of Energy (DOE) has had considerable focus on grid modernization efforts nationally and many of the efforts underway provide valuable context to understand how technologies and practices are advancing in many jurisdictions across the country.

Grid Modernization Efforts on the Federal Level

In November 2014, DOE launched a Grid Modernization Initiative (GMI) to accelerate efforts to shape the future of the electric grid. The Grid Modernization Multi-Year Program Plan, released in November 2015, outlines GMI’s vision of a “future grid [that] will solve the challenges of seamlessly integrating conventional and renewable sources, storage, and central and distributed generation.”⁷⁴ The Plan provides a roadmap of how to support adoption of grid modernization technologies, tools, and modeling approaches, drawing from the Quadrennial Energy Review, the Quadrennial Technology Review, and other DOE initiatives. The Plan identifies six technical priority areas to achieve GMI’s vision:

1. Testing individual devices and integrated systems;
2. Developing tools and strategies to improve grid sensing and measurement;
3. Developing new control technologies to support new generation, load, and storage technologies;
4. Creating simulation and modeling planning tools;
5. Planning for physical and cybersecurity challenges and increasing grid resiliency;
6. Providing technical assistance and institutional support.

⁷³ Title VIII of the [Energy Independence and Security Act of 2007](https://www.congress.gov/bill/110th-congress/house-bill/6/text). <https://www.congress.gov/bill/110th-congress/house-bill/6/text>

⁷⁴ Grid Modernization Multi-Year Program Plan, November 2015. U.S. Department of Energy. <https://energy.gov/sites/prod/files/2016/01/f28/Grid%-Year%-.pdf>

Central to the federal grid modernization is \$220 million that the Grid Modernization Laboratory Consortium (GMLC) is awarding in funding over a three-year period to support 88 research and development projects led by 13 participating DOE National Laboratories. The GMLC coordinates federal grid modernization activities between divisions of the DOE and the national laboratories across the country to strengthen partnerships, promote collaboration, and streamline efficient use of resources. In April 2017, the first grid modernization peer review event was held where researchers shared project updates and gained insights from top experts. In the future, the GMLC intends to expand its partnerships to work with universities, utilities, vendors, and other stakeholders.

The \$220 million federal research and development investment covers a wide range of grid modernization initiatives, spanning methods of energy storage, integrating clean energy resources, as well as strategic planning and modeling tools. Twenty-nine of the 88 projects are considered foundational as they address core grid activities and crosscutting research and development by integrating hardware, software, and institutional approaches to grid modernization. For example, a regional project in Vermont aims to use distributed energy resources to allow for increased renewable energy generation as part of an overall strategy to achieve the state's goal to meet 90 percent of its energy needs with renewables by 2050. The remaining 59 projects are program-specific, and are grouped into one of the six technical priority areas outlined above. These program-specific projects also fall under either grid modeling, solar, or wind categories. One of the solar projects focuses on developing secure, scalable, stable control and communications for distributed solar photovoltaic, building upon the SunShot Systems Integration metrics. The goal of this \$2.7 million project is to ensure security and reliability while increasing the amount of generated solar on the grid. A complete list of projects and updates is available on the Grid Modernization Consortium Laboratory's website.⁷⁵ In addition to federal level initiatives, several states have actively pursued comprehensive grid modernization efforts, including:

- California, through a series of legislative measures, has commenced a comprehensive smart grid initiative as a tool to achieve the state's climate change goals.⁷⁶ The integration with the state's environmental goals is a key driver in California's grid modernization approach. California's grid modernization effort also aims to improve its efficiency and reliability, reduce operations and maintenance (O&M) costs and meet the future demands of new technologies that will be operating on the electric grid.

⁷⁵ See <http://gridmod.labworks.org>

⁷⁶ The enabling legislation is found at <http://www.energy.ca.gov/research/integration/policy.html>

- The Massachusetts Department of Public Utilities (MA DPU) has initiated a set of comprehensive and far-reaching requirements for grid modernization. In 2014, the MA DPU issued an Order requiring that each EDC submit a ten-year grid modernization plan.⁷⁷ Around the same time, DPU issued an Order supporting time-varying rates and another Order pertaining to electric vehicles.⁷⁸
- In 2014, the New York Public Service Commission (NYPSC) launched the Reforming the Energy Vision (REV) comprehensive energy strategy for the state. As part of REV, EDCs develop plans to improve the distribution system planning and grid modernization to effectively integrate DER and other clean energy technologies, connect customers with new options to manage their energy usage, and facilitate innovation to create tailored customer offerings and support investment decisions.

DEEP continues to review and monitor the depth and breadth of grid modernization work currently underway and will continue to identify opportunities to highlight technology advancements and lessons learned to benefit the ongoing work of the EDCs as well as other stakeholders.

Grid Modernization Efforts in Connecticut

Connecticut has made significant gains in seeking demonstration projects for grid side system enhancements and seeking proposals for energy storage systems using its procurement authority.⁷⁹

During the June Special Session in 2015, the Connecticut General Assembly passed Public Act 15-5, An Act Implementing Provisions of the State Budget for the Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State (P.A. 15-5), which requires the EDCs to submit proposals to DEEP and PURA for approval for grid side system enhancements, such as energy storage systems. Grid side system enhancements have the potential to increase grid flexibility and reliability, better integrate clean, distributed generation into the grid, and increase customer participation with the electric grid.

These demonstration projects have mostly focused on comprehensive planning around increased DG penetration from the EDC perspective, through DG forecasting, and from the developer

⁷⁷ Order 12-76-B, Issued in June 2014.

⁷⁸ DPU 14-04 and DPU 13-182, respectively.

⁷⁹ A grid side system enhancement is defined as “an investment in distribution system infrastructure, technology and systems designed to enable the deployment of distributed energy resources and allow for grid management and system balancing, including, but not limited to, energy storage systems, distribution system automation and controls, intelligent field systems, advanced distribution system metering, and communication and systems that enable two-way power flow.” Conn. Gen. Stat. § 16-1.

perspective, through hosting capacity maps to identify points along the distribution system that could benefit from DG.

On February 1, 2017, DEEP released a final determination approving the following projects for the EDCs:

- Eversource's DER Customer Portal and Management System, which will allow Eversource to manage an increasing number of interconnection applications;
- DER Hosting Capacity for Eversource and UI, which will provide the maximum amount of distributed generation that each portion of the circuit can accommodate through a visual mapping tool;
- UI's DER Load Forecasting, which will develop load forecasts based on distributed generation projections; and
- UI's Localized Targeting of DERs, which will target distributed energy resources at a specific substation to provide local distribution system benefits.

These projects will form the foundation, through advanced planning and visibility into distributed energy resources, for expanded grid modernization efforts in the future.

Energy storage systems can provide many benefits to the electric grid, including better integration of variability DER, shifting load from on-peak to off-peak hours, and avoiding costly capacity upgrades on the distribution system. By shifting load from on-peak to off-peak hours, energy storage can also provide environmental and human health benefits by eliminating the need to run older, dirtier power plants during peak hours.

Both Eversource and UI submitted proposals for energy storage systems in the grid side system enhancements demonstration projects proceeding. Projects would be located at specific substations to test out the distribution benefits such system could provide. In its February 1, 2017 final determination, DEEP did not select either project proposal because the potential benefits were not significant enough to justify the high cost.

This represents the beginning of a longer term innovation process. The EDCs recently submitted their proposals to PURA for review and approval and PURA approved Eversource's proposals and is still in the process of reviewing UI's proposals.⁸⁰ The EDCs can adjust their original storage proposals or develop new grid modernization proposals. DEEP expects that the lessons learned

⁸⁰ PURA Docket No. 17-06-02, PURA Review of the Connecticut Light and Power Company's dba Eversource Energy Distributed Energy Resources Proposals; PURA Docket No. 17-06-03, Application for Review of the United Illuminating Company's Distributed Energy Resource Integration Plan.

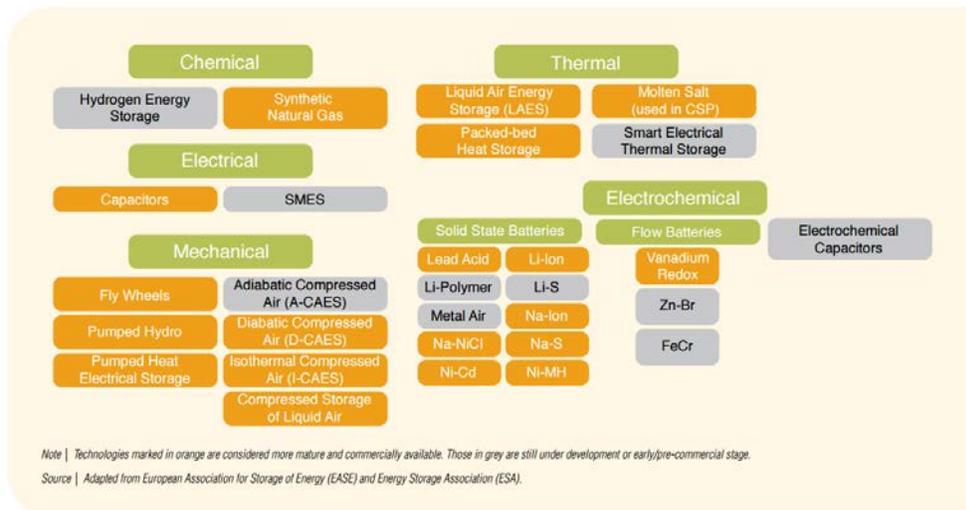
from these projects and those conducted around the country will provide valuable insight as we begin the transition to a more flexible and distributed electric system.

Energy Storage

Within the context of grid modernization additional deployment of energy storage can result in fundamental changes to how our electric grid currently operates. Energy storage systems can provide many benefits to the electric grid, including better integration of variable DER, shifting load from on-peak to off-peak hours, and avoiding costly capacity upgrades to the distribution system. With an array of energy storage technologies deployed and under development across the country, the industry is growing rapidly and costs continue to decline. Energy storage technologies vary in storage capacity, size, intended application, and design:

- Electrochemical technologies are batteries that convert electricity to chemical storage and then back to electricity again. Lead-acid and nickel-cadmium batteries have been used for years, while lithium-ion and sodium sulfur battery technologies have been introduced more recently.
- Electromechanical technologies consist of various mechanisms that temporarily store energy. Compressed air energy storage (CAES) creates a reservoir of compressed air stored in an underground tank. To meet increased electricity demand, the air expands as it is heated and is directed through an expander or conventional turbine-generator. CAES is one example of an established commercial bulk energy storage solution. The flywheel technology, which stores energy in a rotor to then convert the energy to AC power, is more recent and is most commonly used to ensure uninterrupted supply. Pumped hydro is another form of electromechanical storage that has been used for decades throughout certain regions of the U.S.
- Thermal technologies store energy, either as sensible heat – through hot water tanks or ice – or as latent heat, where energy is released through a phase change (e.g., from a solid to a liquid). On a small scale, thermal storage can be used as a distributed energy resource to provide heating or cooling onsite. Molten salt thermal storage can be paired with large-scale concentrated solar power projects, where the technology is able to temporarily store solar energy to help meet demand when the sun is not shining.

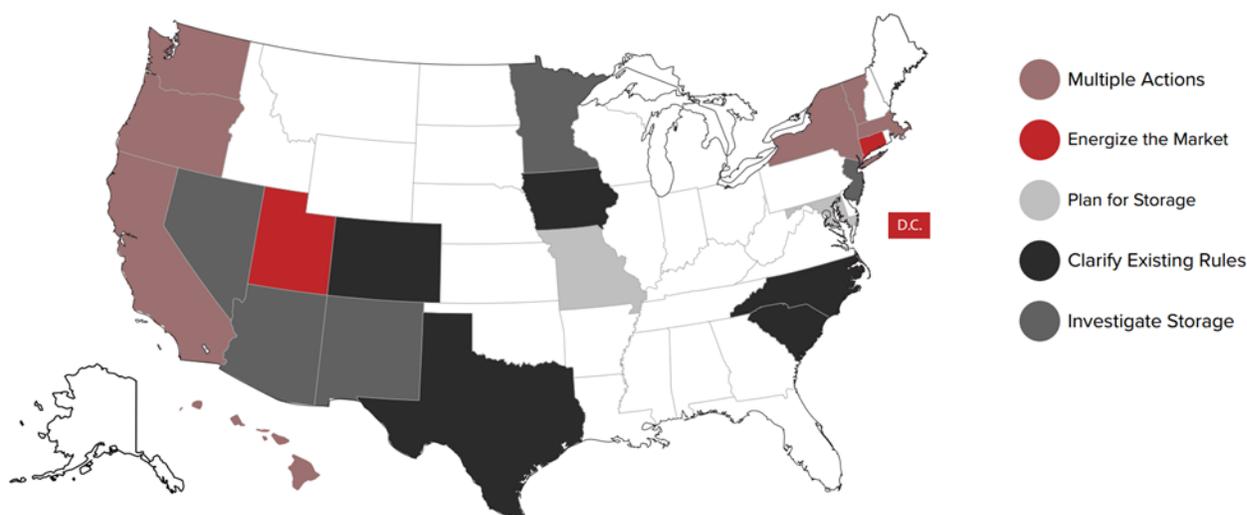
FIGURE E18: Types of Energy Storage Technologies⁸¹



Interest in supporting the energy storage industry has grown in state legislatures in recent years. Electric utility regulators and other government agencies are also exploring approaches to incorporate storage into their energy programming. Figure E19 captures a snapshot of states pursuing at least one legislative or regulatory approach to integrating energy storage.

⁸¹ Energy sector management assistance program, World Bank. 2015, available at <http://documents.worldbank.org/curated/en/185451468124481422/pdf/949400ESMAP0pa0Up0to0Scale0TR006015.pdf>

FIGURE E19: State-level Policies Promoting Energy Storage⁸²



Note: Map is not reflective of all state activities on energy storage. Certain early stage policy/regulatory efforts, grant programs and/or pilot projects may not be reflected herein.

Massachusetts began its multi-pronged Energy Storage Initiative (ESI) in 2015 to help support a transformation of the energy storage market and attract industry players to the state. The Massachusetts Department of Energy Resources (DOER) allocated \$10 million from its 2014 Alternative Compliance Payment Spending Plan to fund energy storage projects, build strategic partnerships, and establish an energy storage market structure. Legislation passed in 2016 allowed DOER to establish targets for electric companies to purchase energy storage systems.⁸³ DOER is soliciting input from stakeholders and is expected to adopt a target in July 2017. In partnership with the Massachusetts Clean Energy Center, DOER also conducted a study on energy storage that outlined current barriers to energy storage adoptions and included policy and program recommendations. Connecticut continues to monitor efforts in Massachusetts to inform Connecticut’s path forward in deploying energy storage.

Federal Energy Storage Efforts

Prior to launching the Grid Modernization Initiative, DOE provided financial and technical support through the national laboratories to advancing the commercial viability of energy storage technologies. The 2009 federal American Recovery and Reinvestment Act included \$4.5 billion through DOE to modernize the electric grid. The DOE established two initiatives, the Smart Grid Investment Grant and the Smart Grid Demonstration Program. Under the Smart Grid

⁸² For more information, visit the National Renewable Energy Laboratory’s Issue brief: A survey of state policies to support utility-scale and distributed-energy storage. September 2014. <http://www.nrel.gov/docs/fy14osti/62726.pdf>

⁸³ Enabling legislation and more details about the Energy Storage Initiative, available at <http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/energy-storage-initiative/>.

Demonstration Program, DOE allocated \$648 million to support 16 energy storage demonstration projects. These cooperative agreements allowed DOE staff to work collaboratively with project operators and required operators to submit final evaluations and project data by 2016.⁸⁴ In addition, DOE maintains a global energy storage database with detailed information on over 1,500 projects, as well as national and global trends, and federal and state-level policies.⁸⁵ The Sandia National Laboratory, in collaboration with the National Rural Electric Cooperative Association, published an Electricity Storage Handbook in 2015 to assist utilities and rural cooperatives design and implement energy storage projects.⁸⁶

Cybersecurity

The 2013 Strategy recommended that PURA, working in conjunction with other relevant State agencies, be charged with conducting a review of Connecticut's electricity, natural gas and major water companies to assess the adequacy of their capabilities to deter interruption of service. Subsequent actions by PURA have included reports of such review together with recommended actions to strengthen deterrence of cyber-related attacks.

In 2014, PURA opened Docket 14-05-12, "Cybersecurity Compliance Standards and Oversight Procedures". During the course of 2015, PURA conducted technical meetings with the various utility industries to obtain their input on applicable cybersecurity standards and oversight for each industry. Specifically, PURA held a series of collaborative technical meetings with the state's public utility companies to review the standards and guidelines they currently follow as part of their cybersecurity risk management programs. This process entailed a review of the adequacy of cyber defenses, the prospect of reaching concurrence on standards and holding annual meetings with government participants.

Moving forward, PURA is working on a Public Utility Company Cybersecurity Oversight Program, wherein the utility companies will have the opportunity to demonstrate, through annual meetings with government stakeholders, that they are adequately defending against cyberattacks. Government stakeholders, including the Public Utilities Regulatory Authority and the Division of Emergency Management and Homeland Security Division (DEMHS), meet with the utilities on cybersecurity issues and report to the Governor, the General Assembly and the Office of Consumer

⁸⁴ Energy storage demonstration project reports, available at https://www.smartgrid.gov/recovery_act/program_impacts/energy_storage_technology_performance_reports.html.

⁸⁵ The U.S. Department of Energy's Global Energy Storage Database, available at <http://www.energystorageexchange.org/>. (Note: As of this writing, the database was last updated in August of 2016.)

⁸⁶ The U.S. Department of Energy/Electric Power Research Institute's 2015 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association, available at <http://www.sandia.gov/ess/publications/SAND2015-1002.pdf>.

Counsel. During these annual meetings, the companies are expected to report on their cyber defense programs, experiences over the prior year dealing with cyber threats and corrective measures they expect to undertake in the coming year.⁸⁷

There is also quite a bit of movement at FERC on cybersecurity.⁸⁸ The proposed Reliability Standards address the cyber security of the bulk electric system and improve upon the current FERC-approved Critical Infrastructure Protection (CIP) Reliability Standards. In addition, the Commission directs North American Electric Reliability Corporation (NERC) to develop certain modifications to improve the CIP Reliability Standards.

⁸⁷ PURA's Cybersecurity Oversight Program reporting requirements will be limited to annual cybersecurity review meetings and will not require the utilities to submit formal, written reports.

⁸⁸ In Docket No. RM15-14-000, FERC approved seven critical infrastructure protection (CIP) Reliability Standards: CIP-003-6 (Security Management Controls), CIP-004-6 (Personnel and Training), CIP-006-6 (Physical Security of BES Cyber Systems), CIP-007-6 (Systems Security Management), CIP-009-6 (Recovery Plans for BES Cyber Systems), CIP-010-2 (Configuration Change Management and Vulnerability Assessments), and CIP-011-2 (Information Protection).