Massachusetts Net Metering and Solar Task Force

Task 1 - Solar Incentive Policy Summaries

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Contents

1 Executive Summary

The Massachusetts Net Metering Task Force is addressing many of the critical issues related to solar market development, including incentive programs and net metering structures, which are currently being discussed in a number of other. A wide range of incentive types have been developed to promote solar market growth, with no U.S. states having identical solar policies. The Task Force has an opportunity to learn key lessons from the development and implementation of solar incentive programs in other states. Literature reviews were conducted to develop policy summaries that discuss the critical elements of a range of incentive mechanisms, from declining block programs to long-term contract solicitations and utility ownership programs. Policies reviewed under this task include:

- The California Renewable Market Adjusting Tariff (Re-MAT), Renewable Auction Mechanism (RAM) and declining block programs;
- The New York declining block programs;
- The Rhode Island Renewable Energy Growth program;
- The Delaware Solar Renewable Energy Credit (SREC) Solicitation program;
- The Connecticut Zero Emissions Renewable Energy Credit (ZREC) program;
- Utility financing, ownership, and long-term contracting programs in New Jersey;
- The Vermont Sustainably Priced Energy for Economic Development (SPEED) long-term contracting program; and
- Value of Solar Tariffs.

The policy choices made to develop each of these unique programs represent efforts by policymakers to balance sometimes-conflicting goals of solar market development scale and speed with ratepayer cost impacts. Summaries have been developed that examine critical policy elements, such as program structure, incentive-setting mechanisms, market size, long-term market goals, complimentary incentives and programs, resulting market characteristics, and other key elements.

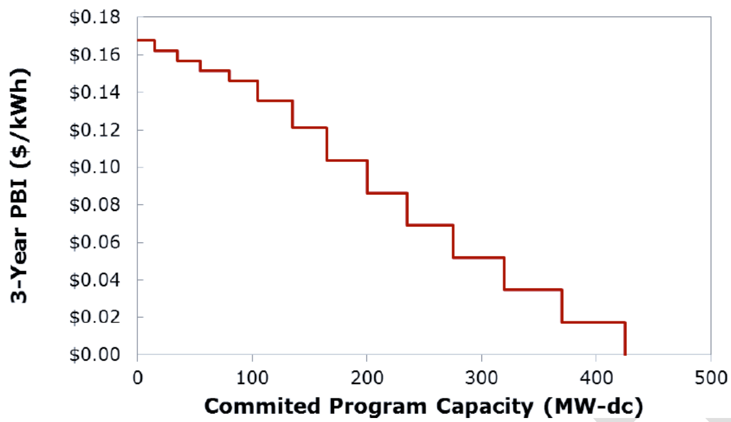
1.1 Policy Types and Key Findings

Policies examined in this report section fall into five broad incentive mechanism types: declining block incentives (DBIs), adjusting block incentives (ABIs), competitive solicitations, value of solar tariffs, and other incentive price setting mechanisms. Descriptions of each of these policies are provided below along with key considerations related to each incentive mechanism.

1.1.1 Declining Block Incentives

Declining block incentive programs have been implemented in both California and New York. This incentive mechanism type establishes a fixed, volume-based incentive schedule whereby incentives are provided at higher levels during the early phases of the program and lower levels in later phases. Once a block of incentives has been fully reserved, the program transitions to a lower incentive tier. This process continues until the total program volume has been reserved and the incentive level has been reduced to zero. Figure 1 illustrates this mechanism and shows the incentive block structure for one New York region.

Figure 1. Proposed Large MW Block Program Incentives for the ConEdison Territory (NYSERDA, 2014)



Block #	PBI ($/W)	Block Volume (MW-dc)
1	$0.63	15
2	$0.61	20
3	$0.59	20
4	$0.57	25
5	$0.55	25
6	$0.51	30
7	$0.46	30
8	$0.39	35
9	$0.33	35
10	$0.26	40
11	$0.20	45
12	$0.13	50
13	$0.07	55

These programs have a predefined fixed budget and also result in a known quantity of solar being developed in advance of the start of the program. A fundamental component of DBIs is that they do not have a defined program timeline, meaning that the rate of solar PV installations under a DBI program will be unknown to policy makers. Declining block incentives are an open-access incentive type, meaning that incentives are distributed on a first-come, first-served basis. They can also be designed to either provide upfront rebates or performance based incentives (PBIs), which pay generators based on the power they produce over time.

The limited number of jurisdictions that have implemented DBIs have achieved market transitions that created self-sustaining solar markets which no longer rely on state-based incentives. These programs also have the advantage of providing market participants with incentive price transparency and can be designed to provide real-time information to market participants about incentive levels and application volumes. Despite these advantages, these programs have, to date, relied on predefined incentive reduction schedules, meaning they may not have the potential to adequately adjust to outside market impacts that could impact solar market growth such as unexpected increases in installed costs or changes to federal incentives. DBIs also have the potential to lead to uneven solar market activity if incentive levels decline more quickly than solar installation costs, making new installations unattractive to potential project owners.

1.1.2 Market Volume Adjustment Mechanisms (CA Re-MAT)

California has implemented a unique solar policy mechanism under its Renewable Market Adjusting Tariff (Re-MAT) program. This program provides solar incentives for a fixed volume of solar capacity through regular bi-monthly incentive offerings. Incentive levels adjust, up or down, in subsequent offerings based on the volume of incentive reserved during the previous incentive period. If the previous period's offering was significantly over-subscribed, incentives in the next offering are lowered. If the previous offering was significantly under-subscribed, the incentive level is raised. Figure 2 below shows this mechanism as implemented in one of the California utility territories.

Figure 2. Re-MAT Adjustment Mechanism

This program type provides an open-access, first-come, first served incentive offering. Because the programs have a fixed volume of capacity that is offered on a fixed schedule, policy makers can define the rate of solar market development as part of the program's design. This incentive type has the advantage of being responsive to outside market influences such as changes to federal tax incentives, making it potentially better able to support solar market stability. Like the DBI programs discussed above, this market mechanism provides near-term incentive price transparency for market participants, but unlike the declining block programs, market volume adjustment mechanisms are not designed to explicitly transition the solar market away from state-based solar incentives. Experience with this incentive model has been limited to date as it has only been implemented by three California utilities.

1.1.3 Competitive Solicitations (RI, VT, CT, CA, DE, NJ)

Competitive solicitations have been used by a number of jurisdictions to award solar PV incentives. Competitive solicitation programs in Rhode Island, Vermont, Connecticut, California, Delaware and New Jersey are profiled in this report. Under this program mode, a competitive process such as a solicitation or auction is used to award incentives, typically using a price-based selection criteria. Regular solicitations are conducted on a pre-determined schedule to create market activity over time. By relying on a competitive process, these incentive mechanisms award incentives to the lowest-cost projects within a market, potentially leading to lower overall policy costs relative to other incentive program mechanisms. These programs are not open access, requiring project developers to win an incentive allocation through a competitive process in advance of developing a project. Market activity for this program type will be defined by the volume and frequency of solicitations, providing policymakers with flexibility to define market activity.

Competitive solicitations have typically been used to provide solar incentives for larger-scale PV systems, as the time and expense of developing pricing proposals for smaller PV systems has been perceived by policy makers as a potential deterrent to residential market activity. These incentive program types may also result in high contract failure rates if programs are not carefully designed to prevent project proponents from submitting low-cost speculative bids. Additionally, infrequent or a limited volume solicitations may result in a small number of project developers receiving incentive awards, potentially reducing market competition over time.

1.1.4 Other Forms of Standard Offer Performance-Based Incentives

In addition to the incentive price-setting mechanisms discussed above, states have also used both administratively-set and competitively-derived mechanisms to determine PV incentive rates. Administratively-set pricing involves conducting cost-based modeling along with a public stakeholder process to determine an incentive level. This mechanism is currently being used as part of the Rhode Island Renewable Energy Growth program and was formerly used in the Vermont SPEED program. This price setting strategy allows policy makers target particular policy goals such as quickly growing the market or rewarding only the lowest cost solar projects. Calibrating pricing to meet these goals may be challenging and pricing incentives incorrectly can lead to unintended market dynamics.

Competitively-derived pricing has been used in Connecticut to establish incentive levels for smaller systems. Under this program, small system incentive levels are set as a function of incentive prices awarded to larger projects in the state's competitive solicitation program. This methodology has the advantage of ensuring that incentive prices are indexed to current market prices. Establishing the appropriate price adder requires careful consideration, as setting the pricing either too high or too low may result in market growth that is either too rapid or too slow.

1.1.5 Value-of-Solar Tariffs (VOSTs)

Value-of-Solar Tariffs are a relatively new incentive type that is intended to eliminate cross-subsidies between participating and non-participating net metering customers. In a VOST, solar generators are provided a per kWh incentive based on the market value of their production. This value is developed through an administrative process and can include elements such as:

- The wholesale value of the generated power,
- The value of avoided transmission and distribution investments,
- Avoided environmental compliance costs, and
- Other societal benefits.

In theory, VOSTs, if properly set should be cost-neutral from the perspective of all utility customers. These rates, however may not be sufficient to support solar market development. To date, Minnesota and Austin, Texas are the first jurisdictions to establish VOST rates.

1.2 Solar Incentive Levels in Other States

Each of the above-listed program types uses different mechanism to incentivize solar market development. Given the unique nature of each state's solar market, including the cost of developing and installing a project, the risks associated with different incentive types, and the availability and value of ancillary incentives, directly comparing incentive levels between states can be challenging. Despite this, reviewing incentive pricing levels in other states may provide Task Force members with critical context that can be used to support the development of recommendations regarding future solar market incentives in Massachusetts. The following table lists current incentive levels for the programs examined in this report chapter. Where applicable, ranges have been provided to indicate incentive levels for programs that provide multiple incentive pricing tiers. Further information regarding the specifics of each incentive program is provided in the following section.

Table 1. Current Solar Incentive Levels in Profiled States

State	Incentive	Incentive Type	Incentive Range
California	California Solar Initiative	Declining Block Incentive, Upfront Rebate or Performance Based Incentive	$0.20 per Watt rebate or $0.03/kWh PBI (non-residential)
	Renewable Market Adjusting Tariff (Re-MAT)	Market Volume Adjustment Mechanism, Performance Based Incentive	$57.23 – 77.23 per MWh PBI (10-20 years)
	Renewable Auction Mechanism	Competitive Solicitation, Performance Based Incentive	N/A
New York	Megawatt Block Program	Declining Block Incentive, Upfront Rebate or Performance Based Incentive	$0.80-0.30 per watt rebate
Rhode Island	Renewable Energy Growth Program	Competitive Solicitation/Administratively Set Price, Performance Based Incentive	$0.1640-.04135 per kWh PBI (15-20 years)
Delaware	Delmarva Power SREC Solicitation Program	Competitive Solicitation	$34.36 - $300 per MWh PBI (7-years + 13 years at $35 per MWh)
Connecticut	ZREC Program	Competitive Solicitation/Competitively Derived Pricing	$60.48 – $81.59 per MWh PBI (15 years)
Vermont	SPEED Program	Competitive Solicitation	$0.1187 to $0.1420/3kWh PBI (25 years)

2 Solar Incentive Policies in Other States

The following sections provide profiles of solar incentive polices in other states. For each program reviewed, a brief description of the incentive structure is provided along with information about key interactions with other state polices and critical observations about state-level solar market dynamics.

2.1 California: California Solar Initiative Declining Block Program, Re-MAT Tariff and Renewable Auction Mechanism Program

2.1.1 Introduction

California's solar market is the largest in the United States and is supported by three major incentive policies for different system sizes. Larger solar projects between 3-20 MW can participate in the Renewable Auction Mechanism (RAM), which requires investor owned utilities to procure 1,229MW of renewables via biennial reverse auctions. Smaller solar projects have historically benefited from a capacity-based, upfront payment incentive or a performance-based incentive (PBI) through the California Solar Initiative (CSI). The value of these cash incentives is based on a declining block structure tied to the overall installed capacity in each of the state's utility territories. Finally, systems 3MW and smaller are eligible for the California Renewable Market Adjusting Tariff (Re-MAT), which provides a 10-20 year standard offer contract based on $/MWh rate set by an innovative solicitation volume adjustment mechanism. These three programs are the focus of this policy profile.

California has a renewable portfolio standard (RPS) which requires 33 percent of each investor owned utility's retail sales to come from renewable or alternative sources by 2020. There is currently no solar carve out to the RPS, however the programs discussed in this section serve to support utility RPS obligations. California has a regulated electricity market, which is managed primarily by the California Independent System Operator (ISO). The California ISO contracts with Load Serving Entities (LSEs), and operates a day-ahead and real-time market.

California has had incentive support for solar since 1998 and California's incentive policies have continued to evolve since their inception. In 2006, Senate Bill 1 established Go Solar California, which funded and established California's existing incentive programs and shifted the market towards performance-based incentives. Administered by the California Public Utilities Commission (CPUC), Go Solar California has a total of $2.8 billion to disperse from 2007 to 2016 and has a target of 3,000MW of installed capacity by 2016.

Similarly, California's net metering policy has also changed as the solar market has continued to grow. In 2008, California allowed limited virtual net metering--or the distribution of net metering credits to multiple off-site locations. In 2013, the CPUC decided to extend the existing net metering program until July 1, 2017 or until individual utility program caps are reached after which distributed generators will receive a new tariff. There is an ongoing discussion on new policies and rate design at the CPUC related to this and other solar market issues.

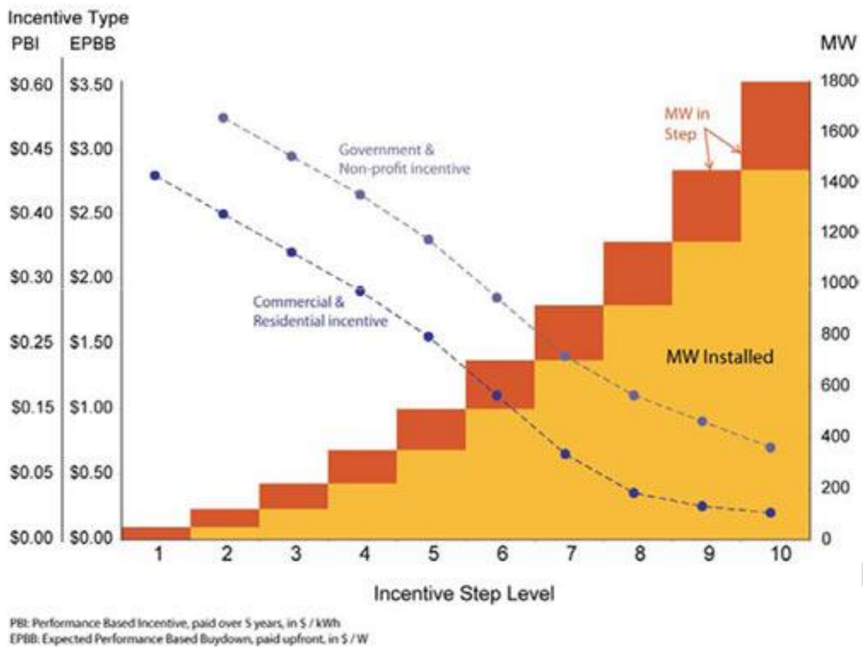
2.1.2 Policy Description

2.1.2.1 Declining Block Program

California developed two declining block incentive programs as part of the California Solar Initiative (CSI) to support smaller scale systems. The Expected Performance Based Buydown Program (EPBB) is an upfront incentive payment for PV systems 30 kW and smaller. Projects 30 kW and larger are eligible for the Performance Based Incentive (PBI) program which provides $/kWh payments based on system output over five years. Smaller systems can choose to opt-in to the PBI program. The incentive amount a system receives is based on a declining 10-step schedule, which is determined by the installed MWs in the program for each utility territory. Non-profits, which are not able to take advantage of federal tax benefits, receive a separate, more generous incentive.

Figure 3 below shows the incentive rates and MW block sizes for the program (Go Solar California, 2015).

Figure 3. CSI Block and Price Diagram



As of January 2015, funds for the program have been nearly fully allocated, with both Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) having completed their allocations and San Diego Gas & Electric (SDG&E) having only 5 MW of program capacity remaining. Since the expiration of the SCE and PG&E incentives, the PV market has continued to grow in those territories without access to the declining block programs. Even without state-funded incentives, California PV system owners still benefit from net metering and federal tax incentives. In particular, California electricity rates typically include inclining volumetric pricing, which can result in high net metering power values that can be highly beneficial for PV system economics.

2.1.2.2 Re-MAT Program

The Renewable Market Adjusting Tariff (Re-MAT) is a standard offer program that provides a PBI for distributed generators under 3MW. California's three largest IOUs (SCE, SDG&E and PG&E) conduct a solicitation every two months for long-term renewable energy contracts of 10, 15 or 20 years. Contracts are for both power and renewable energy attributes. Participating PV system owners are able to select contract lengths at the time of their application. The program solicits contracts from three renewable energy project types: as-available peaking, as-available non-peaking and baseload. These project categories correspond to renewable energy technologies such as solar, wind and biomass respectively. The program offers a fixed capacity in each solicitation and adjusts offer pricing for future solicitations based on whether the prior solicitation was over or under subscribed. The contract rate for each technology type adjusts upward or downward in increments of $4, $8, or $12 based on previous auction volumes. For instance, if a solicitation is significantly undersubscribed, the next solicitation price will increase by $4. If the next solicitation is again significantly undersubscribed, prices in the next round will increase by $8. After three rounds of significant undersubscription, the price will rise by $12. Figure 4 below illustrates the program's price setting methodology while Table 2 illustrates how price increases and decreases are determined based on solicitation volumes (Pacific Gas and Electric, 2013).

Figure 4- Re-MAT Adjustment Mechanism

Table 2. Re-MAT Price Adjustment Mechanism

Subscription for Program Period MWs	Bi-monthly Period Price Adjustment
< 20% (0.0-0.9 MW)	Price Increase
20-99% (1.0-4.9 MW)	No adjustment
>=100% (5.0+ MW)	Price Decrease

The initial tariff level was based on the highest executed contract received by each investor owned utility in the renewable auction process (see discussion of RAM below). Table 3 below shows the historical pricing for the Re-MAT solicitation program for as-available peaking (i.e., solar PV) projects in each of the participating utility territories. Pricing does not include multipliers that are available for delivery of power during peak demand periods. PV systems with Re-MAT contracts can receive an additional 15 percent of their contracted power price for delivering power during critical periods (PG&E, 2015). The first solicitation round opened in October 2013 while the most recent round opened in January of 2015.

Table 3- Re-MAT Prices Rounds 1-8

Utility	Round 1	Round2	Round 3	Round 4	Round 5	Round 6	Round 7	Round 8
PG&E	$89.23	$85.23	$77.23	$65.23	$53.23	$57.23	$57.23	$57.23
Southern California Edison	$89.23	$85.23	$77.23	$77.23	$77.23	$81.23	$81.23	$77.23
San Diego Gas & Electric	$89.23	$89.23	$89.23	$89.23	N/A – segment fully subscribed	N/A – segment fully subscribed	N/A – segment fully subscribed	N/A – segment fully subscribed

As the table indicates, incentive prices have moved sharply down in the PG&E territory since the beginning of the program and have increased slightly during the last several solicitation rounds. In the SCE territory, the contract price initially declined, but has fluctuated near $80 per MWh during much of the program. SDG&E, which had a smaller overall solicitation volume, was fully subscribed after the fourth program round.

2.1.2.3 Renewable Auction Mechanism (RAM)

The CPUC required California's three largest IOUs to procure 1,229 MW of distributed generation to comply with RPS targets. Under the Renewable Auction Mechanism (RAM) program, five auctions occurred biennially between November 2011 and June 2014. A sixth auction was recently approved by California regulators and will include unused capacity from contracts awarded under previous solicitations as well as 75 MW of new capacity. Any generator qualified under California's RPS between 3 and 20 MW is eligible to bid into the auction. Eligible technologies include:

- Photovoltaics
- Solar thermal electric
- Wind
- Certain biomass resources
- Municipal solid waste conversion (Incineration ineligible)
- Geothermal electric
- Certain hydroelectric facilities
- Ocean wave, thermal and tidal energy
- Fuel cells using renewable fuels
- Landfill gas

Bids are selected by the IOUs based on project viability and bid price. Information on bid price is considered confidential and no data has been published on winning bid prices. Solar PV systems have been the majority of projects entering the RAM solicitations and more than 80 percent of the capacity awarded through the program has gone to solar PV systems (Hunt, 2014), (Public Utilities Commission of California, 2014), (San Diego Gas and Electric, 2014).

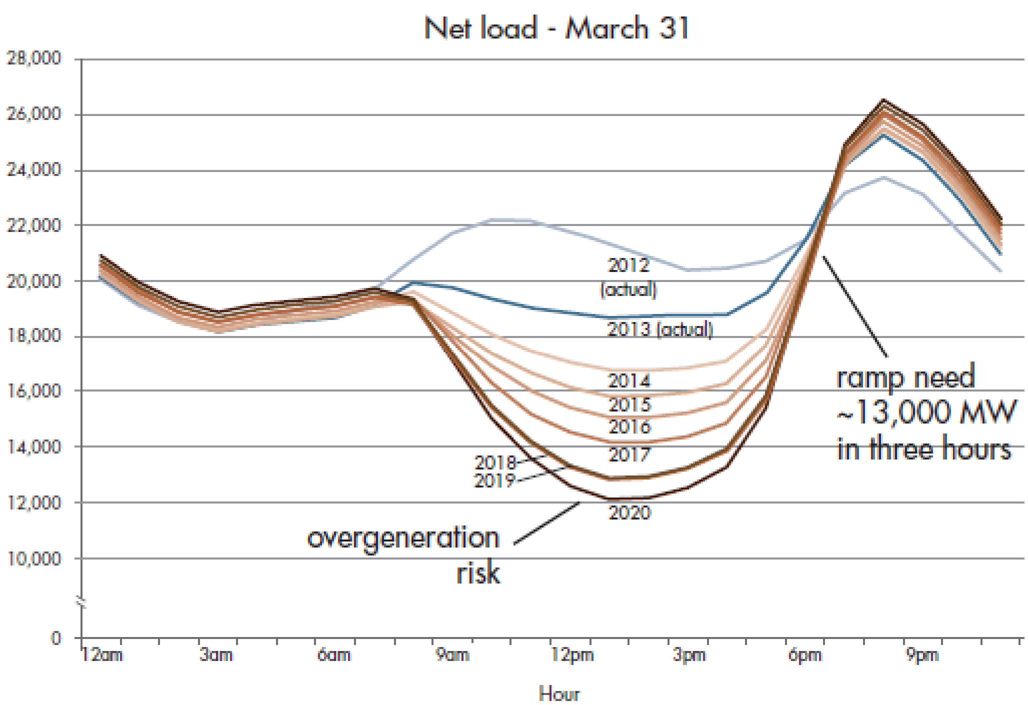
2.1.3 Key Interactions

As described above, California's solar programs are closely interconnected. The RAM, Re-MAT, and the California Solar Initiative are intended to support meeting state-wide RPS targets. The initial rate for the Re-MAT program was determined based on the results of the latest reverse auction held through the RAM process. Solar systems cannot benefit from both cash-based CSI rebates and the Re-MAT program. Additionally, many customer-sited systems participating in the CSI program benefit from net metering, which can be a substantial benefit given California's inclining block electricity rate structure. High net metering values have likely contributed significantly to the continued growth of the state's residential solar market since the end of the CSI program.

2.1.4 Impact and Observations:

California ranks first in the nation for installed PV capacity, and over half of the state's current installed capacity came online in 2013 (2,756MW of solar installations). Even though the declining block incentives have either been fully exhausted or have reached their enrollment caps, distributed solar continues to grow in California. Average installation costs have also continued to decline, falling 6 percent over the last year. (Solar Electric Industries Association, 2015). Existing installations and expected solar market growth in California has required the grid operator to consider future operating paradigms that are substantially different from historical demand patterns. Known in the industry as the "Duck Curve," the California ISO has developed a forecast under likely expected solar PV market penetrations in which the net power requirements on the grid drop considerably during hours of peak sunshine as utility customers generate more of their own power. Stakeholders in the state are actively engaged in exploring how flexible grid resources can be deployed to manage the energy supply and demand paradigms (California ISO, 2015).

Figure 5. The Cal-ISO Duck Curve Load Projections



As a large state with a substantial renewable energy RPS commitment, California has implemented a range of PV incentive programs that have created a diverse market. Creating incentive programs within distinct utility territories with different incentive pricing levels has allowed California's solar market to accommodate geographic differences in solar resources and local solar market conditions. As was seen in both the Re-MAT and CSI initiatives, the pricing and market development rates have been different in each utility territory allowing these state sub-markets to develop without a single region of the state receiving a disproportionate amount of solar incentives. This approach may be a viable option in Massachusetts where differences in real estate costs, PV installation costs and retail electricity prices could potentially create geographic imbalances in solar market development under a single incentive structure.

Both the Re-MAT and CSI declining block programs are innovative incentive setting mechanisms that overcome some of the challenges associated with typical standard offer and rebate-based programs. By establishing clear program criteria and adjusting incentive levels based on market conditions, these programs have limited ratepayer risk of over-subsidization. Additionally, the declining block incentive framework was structured to move the state's distributed solar market away from subsidies in a market-responsive fashion. Additionally, the fixed program budget and defined MW program target provides significant transparency into program costs. This mechanism has been adopted by New York as part of that state's latest incentive program iteration. One notable feature of the Re-MAT program is the ability of this structure to increase incentive prices in response to changing market conditions. This policy feature is likely to make Re-MAT-like mechanisms more responsive to changes outside the control of state and utility program administrators such as changes to federal incentive policies or increases in global PV system component costs. Finally, the RAM program has shown that, at least in the California market, large scale solar PV systems can effectively compete against other renewable energy generators.

As with all programs that require centralized program managers to award incentives, some proportion of projects that are awarded incentives will not be constructed. This can result in programs not meeting overall market capacity goals and can frustrate developers with viable projects that were not awarded contracts. Both the Re-MAT and RAM programs have bid deposit mechanisms that are intended to prevent speculative bidding (PG&E, 2015). While these mechanism are in place to limit potential contract failures, several of the California utilities routinely discount the expected production of renewable energy systems they have under contract but which have not yet been completed as part of their RPS obligation forecasts because of expected project failure rates.

The suite of incentive programs implemented in California over the past several years has resulted in steady market growth and the development of a sustainable PV industry in the state. The unique incentive rate setting mechanisms pioneered in California may be worth considering in the Massachusetts context as they provide market-responsive incentive pricing with standard offer, open-access incentives.

2.2 New York Megawatt Block Incentive Program

2.2.1 Introduction

In comparison to other East Coast states such as New Jersey and Massachusetts, New York has historically had a relatively small solar market. In 2012 Governor Cuomo launched the NY-SUN initiative, a $1 billion program to drive the development of 3 GW of solar PV by 2023. A continuation and expansion of previous state programs, the NY-SUN initiative fits within the framework of New York's RPS policy, which has a current goal of supplying 30 percent of the state's power from renewable sources by 2015. The state RPS is implemented through a two-tiered system with a Main Tier for utility-scale systems and a Customer-sited Tier (CST) for distributed installations. NYSERDA centrally procures the RPS Main Tier through regular solicitations for long-term contracts. NYSERDA implements several programs as part of the CST including programs for fuel cells, anaerobic digesters, small wind installations and solar PV. NYSERDA's solar PV programs, which have been in place since 2003, are now operated under the umbrella of the state-wide NY-SUN initiative. The state's current solar program offerings include a declining block incentive program called the Megawatt Block program. In early 2015, this program will expand to include larger-scale solar projects over 200 kW, which were previously supported by a competitive solicitation process. Funds for the program are paid for via RPS charges on ratepayers.

In 2010, the New York RPS target was expanded from 25 percent by 2013 to 30 percent by 2020. The Customer-sited Tier was also expanded from 2 percent to 8.44 percent. The New York Public Service Commission (PSC) recently raised the state net metering cap from 3 percent to 6 percent of 2005 peak demand after concerns that the existing cap would not enable the market to reach current goals. The PSC also commissioned a study on net metering impacts and a future value-based tariff.

New York has had retail electric competition since the 1990s, and the New York Independent System Operator (NYISO) serves as the transmission system operator for the state. The NYISO also operates capacity and ancillary service markets. The state has six investor owned electric distribution companies (EDCs) in addition to the Long Island Power Authority (LIPA), a public-power provider serving Long Island that has been recently rebranded as PSE&G Long Island. The territories of the investor owned EDCs have traditionally been under the jurisdiction of NYSERDA programs while the former LIPA territory has historically developed and implemented its own renewable energy policies. This has recently changed with NYSERDA now supporting renewable energy programs in the former LIPA territory.

2.2.2 Policy Description

New York's small-scale Megawatt Block program is an incentive program that provides upfront payments in the form of rebates calculated as a dollar per watt incentive. The program's incentive rate declines as MWs of capacity are enrolled in the program on a predetermined schedule. The current program provides incentives for PV systems up to 200kW. In recognition of the differing economics of PV systems across the state, NYSERDA has defined separate incentive levels and declining block schedules for the upstate region, ConEdison's territory and Long Island. Within each regional territory, a separate incentive with a distinct declining block schedule has been defined for residential and non-residential systems. The incentive is made available to installers approved by NY-SUN who then pass the savings on to consumers. PV systems in the program must serve less than 110 percent of on-site load. Non-residential systems receive a larger incentive for the first 50 kW of capacity and receive a smaller incentive for the remainder up to 200 kW. The step schedules for each utility territory are provided in Table 4 and

Table 5 below along with the total MW expected from the program for each territory.[1] In each table, the current incentive block as of January 2015 is highlighted.

[1] Long Island has traditionally had a more robust solar market with lower installed costs. Additionally, electricity rates in Long Island are generally higher than those in many other parts of the state. The program incentive levels reflect these factors.

Table 4- Residential Program Tiers for Long Island, Con Edison and Upstate NY (NYSERDA, 2015)

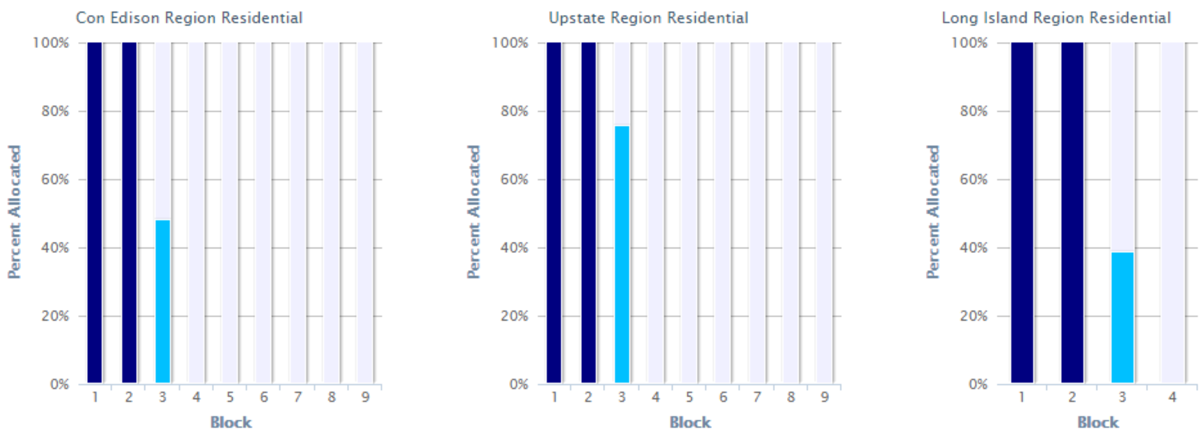
	Long Island		**ConEdison**		**Upstate**	
BLOCK	MW	$/WATT	MW	$/WATT	MW	$/WATT
1	37	$0.50	14	$1.00	40	$1.00
2	15	$0.40	6	$0.90	15	$0.90
3	**20**	**$0.30**	**9**	**$0.80**	**19**	**$0.80**
4	50	$0.20	12	$0.70	22	$0.70
5			15	$0.60	24	$0.60
6			18	$0.50	31	$0.50
7			38	$0.40	70	$0.40
8			70	$0.30	75	$0.30
9			120	$0.20	148	$0.20
Total	**122**	**$40.5 MM**	**302**	**$113.2 MM**	**444**	**$194.1 MM**

Table 5 - Non-residential Program Tiers for Long Island, Con Edison and Upstate NY (NYSERDA, 2015)

	Long Island			**ConEdison**			**Upstate**		
BLOCK	MW	0-50kW $/WATT	50-200kW $/WATT	MW	0-50kW $/WATT	50-200kW $/WATT	MW	0-50kW $/WATT	50-200kW $/WATT
1	7	$0.50	$0.50	6	$1.00	$0.60	35	$1.00	$0.60
2	**6**	**$0.45**	**$0.43**	**4**	**$0.90**	**$0.55**	8	$0.90	$0.55
3	7	$0.40	$0.36	6	$0.80	$0.50	10	$0.80	$0.50
4	9	$0.35	$0.30	8	$0.70	$0.45	**12**	**$0.70**	**$0.45**
5	15	$0.25	$0.23	10	$0.60	$0.40	18	$0.60	$0.40
6	14	$0.15	$0.15	15	$0.50	$0.35	23	$0.50	$0.35
7				35	$0.40	$0.30	28	$0.40	$0.30
8				45	$0.30	$0.25	77	$0.30	$0.25
9				73	$0.20	$0.20	95	$0.20	$0.20
10				101	$0.15	$0.15	145	$0.15	$0.15
Total	**58**			**303**			**451**		

NYSERDA maintains a website that provides real-time data on incentive step levels and provides data on the current volume of capacity that has been reserved. This allows solar stakeholders to have an up-to-date view of when incentive levels could decrease. Figure 6 below shows the online dashboard developed by NYSERDA for the program.

Figure 6. NYSERDA MW Block Program Dashboard (NYSERDA, 2015)



In addition to the small scale Megawatt Block Incentive Program, NYSERDA is in the process of developing a similar program for larger systems (customer-sited systems greater than 200kW). Like the program for smaller systems, this program will have a defined schedule of incentives that decline over time based on total volume installed. Unlike the program for smaller systems, the new program will provide incentives as a hybrid of a performance based incentive (PBI) and an upfront payment. The total maximum incentive will be based on the current block dollar per watt incentive level. This capacity-based incentive level will be used to calculate a maximum potential system incentive and associated $/kWh performance based incentive. System developers will be provided with 25 percent of the maximum incentive upon commercial operations of the system and then will be provided three annual payments that will be based on the systems actual production multiplied by 75% of the maximum system performance based incentive. Table 6 below illustrates a hypothetical 500kW system receiving a $0.63/kW block incentive. This table shows an ideal circumstance under which the PV system produces its estimated annual production. In the event that the system produces less than the expected production, the system owner's annual production-based compensation would be lower than the maximum available incentive.

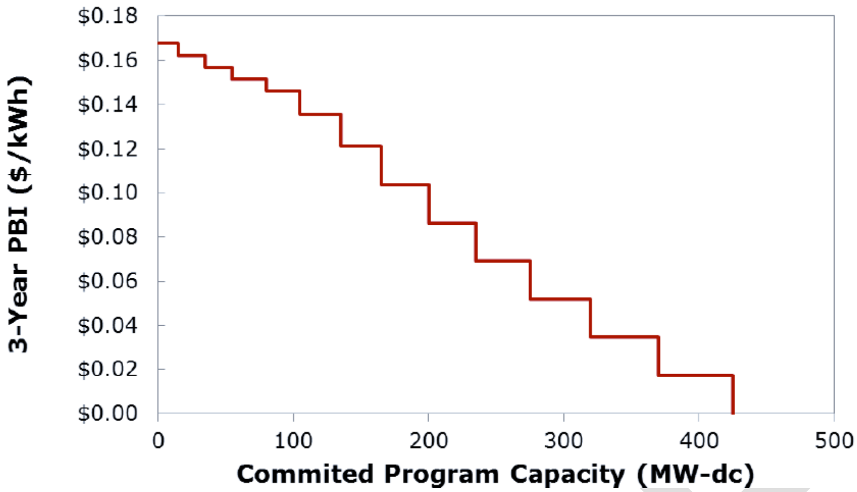
Table 6. Illustrative Example of Incentive Calculation Under the Proposed NYSERDA Large System MW Block Program (NYSERDA, 2015)

Parameter	Value	Calculation
System Size	500kW	
Annual Production	586,920	(500 kW) X (13.4% Capacity Factor) X (8760 hours per year)
Maximum Incentive Amount	$315,000	(Total System Size) X ($0.63/kW Incentive)
Three year per kWh Incentive Amount	$0.179	(Maximum Incentive)/(Annual Production X 3 Years)
Upfront Payment at Commercial Operations	$78,750	25% X Maximum Incentive Amount = (.25) X ($315,000)
Year One Performance Payment	$78,750	75% X Three Year kWh Incentive X Annual Production = (0.75) X (0.179) X (58,6920)
Year Two Performance Payment	$78,750	(75%) X (Three Year kWh Incentive) X (Annual Production) = (0.75) X (0.179) X (58,6920)
Year Three Performance Payment	$78,750	(75%) X (Three Year kWh Incentive) X (Annual Production) = (0.75) X (0.179) X (58,6920)
Total Incentive	**$315,000**	Upfront Payment + Year One Payment + Year Two Payment + Year Three Payment

The current proposed large-scale Megawatt Block Incentive Program also provides 20 percent incentive value adders for locating PV systems in strategically critical locations as defined by the local electric distribution utility. This added incentive is intended to improve the economics of systems in geographic areas where solar PV has the greatest value to the grid. Figure 7 and Figure 8 show the current proposed incentive rates, block volumes and associated $/kWh incentives for the ConEdison territories and the remainder of the state.

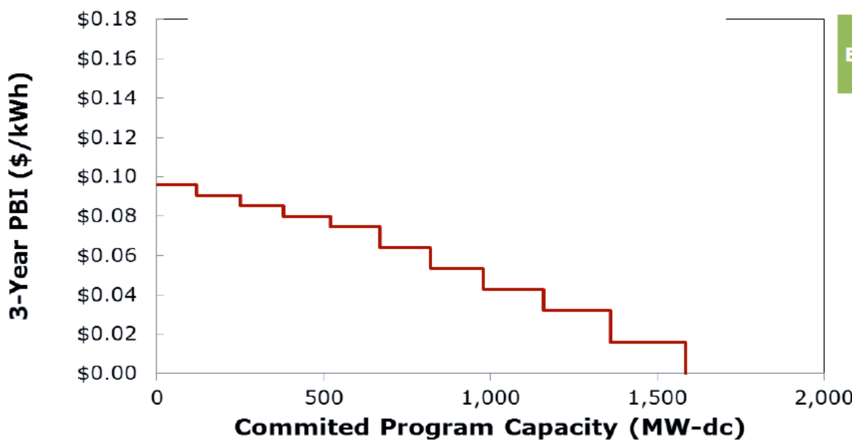
The remainder of the state incentive program has been geographically divided into a western region, with higher early incentives, and a non-western region.

Figure 7. Proposed Large MW Block Program Incentives for the ConEdison Territory (NYSERDA, 2014)



Block #	PBI ($/W)	Block Volume (MW-dc)
1	$0.63	15
2	$0.61	20
3	$0.59	20
4	$0.57	25
5	$0.55	25
6	$0.51	30
7	$0.46	30
8	$0.39	35
9	$0.33	35
10	$0.26	40
11	$0.20	45
12	$0.13	50
13	$0.07	55

Figure 8. Prosed Large MW Block Incentive Levels for non-ConEdison New York Regions (NYSERDA, 2014)



Block	PBI ($/W) ROS*	PBI ($/W) ROS-W*	Block Volume (MW-dc)
1	$0.36	$0.40	120
2	$0.34	$0.39	130
3	$0.32	$0.36	130
4	$0.30	$0.34	140
5	$0.28	$0.29	150
6	$0.24	$0.26	150
7	$0.20	$0.20	160
8	$0.16	$0.16	180
9	$0.12	$0.12	200
10	$0.06	$0.06	225

As currently proposed, the large system Megawatt Block Incentive Program would support 340 MW in the ConEdison territory at a total cost of $125 million. The estimated budget for the remainder of the state is $300 million and is expected to support 1,235 MW (NYSERDA, 2014).

2.2.3 Key Interactions

Megawatt Block Incentive Program participants assist with the achievement of the Customer-sited Tier of the New York RPS. Solar Renewable Energy Credits (SRECs) are not available in New York, therefore system owners receive these rebates in lieu of an SREC-based incentive. New York State also offers a 25 percent residential solar tax credit of up to $5,000, a sales tax exemption, and has loans available for solar systems through NYSERDA. Jurisdictions in New York also have the option to offer a property tax exemption for solar in an effort to reduce soft costs. Systems taking advantage of the Megawatt Block Incentive Program can also benefit from net metering in New York State. In New York, excess generation is credited at the full retail rate with annual excess generation credited at avoided cost rates. New York does allow remote net metering under which individual customers can allocate net metering credits to other accounts they are responsible for (NY PSC, 2011).

2.2.4 Impact and Observations

In designing the Megawatt Block Incentive Programs, NYSERDA sought to "provide certainty and transparency to the industry regarding incentive levels" and to provide incentives that account for differences in regional solar installed costs. The program was also designed with the intent of driving the state towards a self-sustaining market that was not reliant on state incentives (NYSERDA, 2014). The MW Block program is a relatively new incentive program with the small scale program launched in August 2014 and the large-scale program expected to be launched in early 2015. The early stages of the small-scale program have seen robust uptake in several regions. For instance the Long Island residential program tranche has already allocated 64 MW of the program's expected 122 MW, reducing the incentive level from $0.50 per watt to $0.30 per watt. Despite this early success, it is too early to evaluate how the market has responded to this program compared to previous NYSERDA offerings.

As a standard offer program with open access for approved installers, the NYSERDA Megawatt Block Incentive Program provides the benefits of an open-market program that does not require regularly scheduled solicitations. In theory, this market feature should reduce installation cost as project developers will not need to enter competitive solicitations that can have significant uncertainty and administrative costs. This program feature will provide certainty and transparency to developers and should promote long-term industry growth. Counter to that benefit, the Megawatt Block Incentive Program has set a fixed incentive schedule, meaning that, in the event of changes from external market factors, such as major increases in global solar component costs or the expiration of federal tax benefits, the rigid structure of the Megawatt Block Incentive Program could create market contractions. In the event of such an occurrence, policymakers may feel significant pressure to revise incentive levels in order to prevent industry job losses. The pending reduction in the federal Investment Tax Credit could present a major challenge to declining block programs.

In designing the large-scale Megawatt Block Incentive Program, NYSERDA has established geographically distinct incentives for different state regions as well as bonus incentives for installations located in utility-identified regions where installations have the greatest value to the grid. This model may be of interest to Massachusetts policy makers as several stakeholders in the Massachusetts Net Metering Task Force process have suggested that location-based incentives that promote grid benefits be considered. As further details about the final design of the large-scale Megawatt Block Incentive Program become available, the effectiveness of this approach could be further evaluated. One additional potential consideration with this approach are potential equity concerns related to differentiated program incentives. Solar incentives are paid for by all ratepayers yet only a sub-segment of ratepayers will have properties that allow them to take advantage of solar incentives. These incentive distributional effects may be further concentrated if added incentives are preferentially distributed to ratepayers in geographically defined areas.

The New York Megawatt Block Incentive Program has a fixed budget and predefined step-down schedule. This means that program administrators know the full cost of the incentive program at inception. This provides greater transparency compared to SREC market-based mechanisms in which annual compliance costs can be estimated, but not fully known in advance. While the overall cost of the program can be known in advance, with a fixed budget and schedule, but no fixed timeline, estimating annual program costs will depend on market response to incentive levels.

As a program with limited available data, project success and failure rates are unavailable at this time. That said, NYSERDA has proposed an enrollment mechanism for the large-scale program that is intended to prevent developers from reserving incentives and not moving forward with projects. This includes a reservation security deposit of up to 15 percent of the total estimated incentive or $25/kW, whichever is greater. Additionally, installers will have 18 months to install projects once incentives have been reserved (with the ability to apply for a 6 month extension if certain criteria are met).

The New York Megawatt Block Incentive Programs build off the model pioneered in California under the California Solar Initiative. In that state, the steadily declining incentives lead to a stable, unsubsidized residential solar market that has continued to grow over time. The New York declining block programs may repeat this success, however it remains to been seen whether this model will prove resilient in the likely event that major reductions occur to federal solar investment tax incentives. Regardless, the New York Megawatt Block Incentive Program has established a transparent incentive framework with standard offer incentives and a fixed program budget that could serve as a potential model for consideration by the Massachusetts Net Metering Task Force.

2.3 Rhode Island Renewable Energy Growth Program

2.3.1 Introduction

Rhode Island's Renewable Energy Growth (REG) Program offers 20-year utility tariffs[2] to qualifying solar, wind, anaerobic digestion and hydroelectric projects through a competitive process. The program is administered by the Office of Energy Resources (OER) and the Distributed Generation Board and is effectively an extension of the Distributed Generation Standard Contracts (DG SC) Pilot Program, which operated from 2011 to 2014. Maximum contract rates (referred to as "ceiling prices") are approved annually by the Public Utilities Commission (PUC). National Grid, the state's sole investor-owned utility, manages the competitive solicitations and enters long-term tariff agreements with successful bidders. The REG Program's objective is to successfully develop an incremental 160 MW of distributed generation in Rhode Island by 2019 (RI REF, 2015).

Rhode Island operates a competitive retail electric market, which was established through the Rhode Island Utility Restructuring Act of 1996. National Grid provides distribution service to the vast majority of the state's customer load. Retail customer access to competitive markets began in 1997, with National Grid assigned as the provider of Standard Offer service for customers electing not to switch their generation service.

Rhode Island offers a supportive policy environment for renewable energy, particularly for small on-site and distributed generation projects. The state has established a Renewable Energy Standard (RES), a long-term contracting standard for 90 MW of RES-eligible renewables as well as offshore wind supply, net metering, a Renewable Energy Fund which administers grants and loans, a DG Standard Contracts Program and the current REG Program. The RES was enabled in 2004 and originally required load-serving entities to supply 16 percent of retail sales with qualified *New* (14 percent) and *Existing* (2 percent) renewable energy resources[3]. Rhode Island's net metering program enables generators up to 5 MW to offset retail electric bills. Generators must be "reasonably designed" to provide up to 100 percent of a customer's annual electricity consumption (up to 125 percent for any individual billing cycle), so deliberately oversized projects are excluded. Net excess generation is credited at the utility's avoided cost. Multiple meters on a single, or adjacent, property may be aggregated, but virtual net metering is not offered – except to facilities owned by, or owned and operated on behalf of, municipalities or other public entities. There is an aggregate net metering capacity limit of 3 percent of peak load for Block Island Power Company and Pascoag Utility District, but this limit was removed for National Grid, which serves as distribution utility for the majority of load in the state. The Rhode Island Renewable Energy Fund[4] (REF) is a public benefits fund created by the 1996 restructuring legislation which offers grants and loans to a wide range of renewable projects. The REF currently supports four program areas: small solar, commercial development, feasibility studies, and early-stage commercialization. Small solar is supported primarily through a block grant program (currently offering grants of $1.15 per watt to a maximum of $10,000) (RE Growth Program Public Review Meeting, 2015).

The REG Program, which is just beginning in 2015, was developed in accordance with RIGL § 39-26.6-4 (a) (1) and the applicable provisions of RIGL § 39-26.2-4 and 39-26.2-5. It succeeds and replaces the Distributed Generation Standard Contracts Pilot Program, which had been in place since 2011 and offered up to 40 MW of 15-year power purchase agreements with National Grid through a similar competitive process. Both programs were developed in response to increasing pressure to attract the potential for renewable energy job and economic development to Rhode Island. The RES – while successful at meeting its goals to date – has largely resulted in procurement from out of state generators. Recognizing Rhode Island's limited land area and resource potential to support large-scale projects, policymakers turned their focus to distributed generation. The DG SC Program has successfully encouraged grid-connected projects between 50 kW and 3 MW. The REG program will expand the reach of this policy to include residential customers,

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[2] A host-owned solar projects < 10 kW has the option to elect a 15-year tariff.

[3] In a 2014 determination of resource inadequacy, the PUC delayed the 2015 *new* RES target increase by one year and called for the overall *new* target to truncate at 12.5 percent rather than 14 percent.

[4] The REF was created under the Office of Energy Resources and is administered by the RI Commerce Corporation.

streamline the contracting process by replacing Power Purchase Agreements (PPAs) with tariffs, and grow Rhode Island's distributed generation mandate to a total of 200 MW by 2019 – a substantial sum for a small state (RE Growth Program Public Review Meeting, 2015). It is designed to do so in a manner that is not additive to the net metering incentive, as discussed further below. As of January 2015, the DG SC program has concluded with 39.07 MW currently under contract, most of which is solar PV. Sixteen projects are operating and the remainder is under development. The REG Program commences in 2015, with a first-year contracting target of 25 MW (RI REF, 2015).

2.3.2 Policy Description

The REG Program offers a long-term, fixed price tariff between National Grid and qualifying renewable energy projects which is implemented as a performance-based incentive. The tariff approach replaces the use of contracts under the DG Standard Contract program. Host-owned solar projects less than 10kW may elect either a 15- or 20-year tariff. All other projects receive a 20-year tariff. Pricing is fixed and flat for the duration of the agreement. For solar projects up to 250 kW, fixed tariff pricing is approved by the PUC on an annual basis – there is no price bidding for these projects, and program MW are awarded on a first-come, first-served basis (H.7727 The Distributed Generation Growth Program, 2015).

All other projects must bid in response to one of up to three competitive solicitations offered annually. Awards are made based on price, assuming all other eligibility criteria are met. For successful projects, tariff pricing is "as-bid" and is paid by National Grid for all production. Once a contract is awarded, projects have 24 months (solar and wind) to achieve commercial operations.[5] A performance guarantee deposit is required to maintain each project's position in the program during this time. For projects less than 1 MW, a security of $15/REC (for total estimated REC production) must be received within 5 days after a project is awarded a place in the program through a Certificate of Eligibility. For projects of 1 MW or greater, a security of $25/REC is required. The exceptions to this rule are solar projects up to 250kW, for which no security deposit is required. National Grid is authorized to grant one 6-month extension at no cost for non-residential projects for unforeseen delays. A second 6-month extension (for a total of 12 months) may be granted if the project provides an additional security deposit of 50 percent of the original performance guarantee.

The DG SC Program was implemented using PPAs, which had the unintended consequence of protracting contract negotiations (after awards had been made) due to the critical link between offtake arrangements and project financing. Contract negotiations, the process of securing PUC approvals, and administration also placed a large burden on National Grid personnel. A cornerstone of the new REG Program is its implementation through utility tariffs. Policymakers, utilities and project developers hope that this will streamline the process while still satisfying financial institutions. Policymaker objectives with respect to project type have also evolved. The DG SC Program accepted only projects greater than or equal to 50 kW and interconnected on the utility's side of the meter. By comparison, the REG program allows residential participation, including a legislated target of 3 MW in the first program year. All projects under the REG program are required to have a generation (net) meter, which is interconnected on the utility's side of the host customer service meter.

The programmatic goal of 160 MW is divided into annual targets, and then further divided into segments by technology and project size. For example, the 2015 REG program will offer tariff to up to 25 MW of projects, allocated as follows:

[5] 36 months for anaerobic digesters or 48 months for hydroelectric.

Table 7. Allocation of 2015 Renewable Energy Growth Program MW

Technology & Eligible Class	kW Allocations
Small Solar I – Host Owned	3,000 kW* DC
Small Solar I – Third Party Owned/Financed	
Small Solar II	
Medium Solar	4,000 kW DC
Commercial Solar	5,500 kW DC
Large Solar	6,000 kW DC
Wind I	5,000 kW DC
Wind II	
Anaerobic Digestion I	1,500 kW DC
Anaerobic Digestion II	
Small Scale Hydropower I	
Small Scale Hydropower II	
Total	25,000 kW

***The REG statute requires a minimum of 3 MW be allocated to the small solar class during the 2015, 2016, 2017 and 2018 program years.*

Annual program targets for the remaining program years are as follows: 50 MW in each of 2016 through 2018, and the greater of 15 or all of the remaining MW in 2019. In addition, any remaining (un-contracted or unsuccessful) MWs from the DG Standard Contracts Pilot Program will be added to the 2019 REG target (Tariff Advice Filing for Renewable Energy Growth Program and Solicitation and Enrollment Process Rules, 2014).

Competitively bid tariff rates are subject to a cap, which is referred to as a ceiling price. Ceiling prices are set administratively (by the PUC), based on recommendations developed by the OER and DG Board through a public research- and stakeholder comment-driven process. Independent research and stakeholder data submittals are combined in a consultant analysis which analyzes the levelized contract price required to enable projects to cover their costs and achieve a market-based, risk-adjusted rate of return. Ceiling prices are approved for each technology and size category. For example, the recommended 2015 REG ceiling prices are as follows:

Table 8: Recommended 2015 REG Ceiling Prices

Technology	Ceiling Prices (¢/kWh)
Small Solar I – Host Owned (15 Year Tariff)	41.35
Small Solar I – Host Owned (20 Year Tariff)	37.75
Small Solar I – Third Party Owned/Financed	32.95
Small Solar II	29.80
Medium Solar	24.40
Commercial Solar	20.95
Large Solar	16.70
Wind I	22.75
Wind II	22.35
Anaerobic Digestion I	20.60
Anaerobic Digestion II	20.60
Small Scale Hydropower I	21.35
Small Scale Hydropower II	21.10

Table 9 provides a summary of historic ceiling prices, established during the DG Standard Contracts Program.

Table 9. Historic Ceiling Prices*, DG Standard Contracts Program 2012-2014

Technology Class	2014		2013		2012	
	Size	¢/kWh	Size	¢/kWh	Size	¢/kWh
Small Solar			50-100 kW	29.95	10-150 kW	33.35
Medium Solar	50-200 kW	27.10	101-250 kW	28.80		
Commercial	201-500 kW	27.30	251-499 kW	28.40	151-500 kW	31.60
Large Solar	501-3000 kW	23.50	> 500 kW	24.95	501-1000 kW	28.95
Wind	1.0-1.5 MW	17.50	1.0-1.5 MW	14.80	N/A	13.35
Hydro	50 kW-1.0 MW	17.90	400-500kW	17.90		
Anaerobic Digestion	50 kW-1.0 MW	18.55	0.5-1.0 MW	18.55		

** Including ITC (Solar, Wind) or PTC (Hydro, AD); without Bonus Depreciation*

The combination of ceiling prices and competitive solicitations has yielded declining contract prices over time. Figure 9 demonstrates the decline in DG Standard Contract Ceiling Prices between 2012 and 2014, and includes the recommended REG Ceiling Prices for 2015.

Figure 9. Ceiling Price Decline, 2012 - 2015

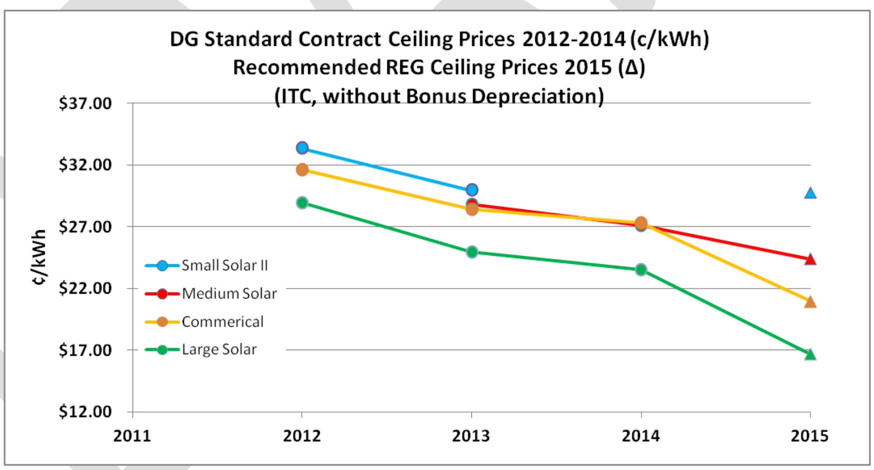
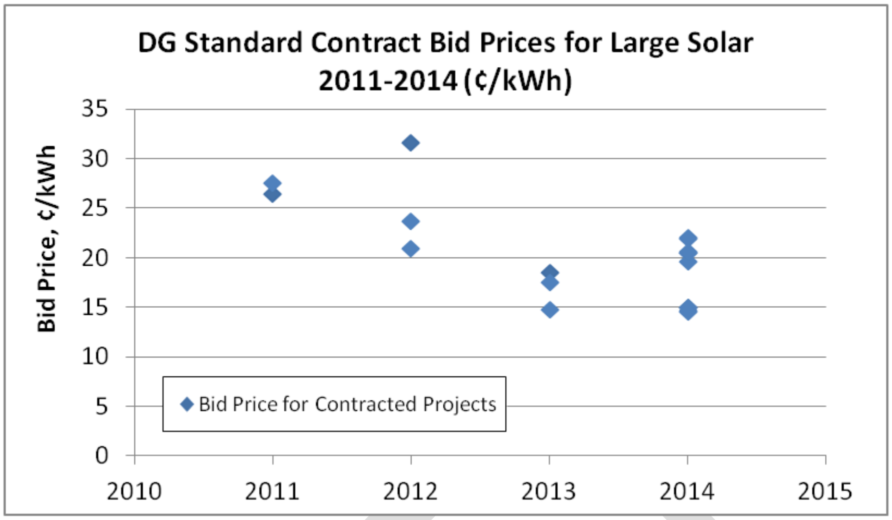


Figure 10 demonstrates the range, and overall decline, in the bid prices of large solar projects selected for DG Standard Contracts between 2011 and 2014. As can be seen, prices have at times been well below the ceiling prices, although in 2014 this trend leveled off (anecdotally, prices in 2013 were reportedly at unsustainable/unprofitable levels).

Figure 10: Bid Prices of Large Solar Projects Selected for Standard Contracts, 2011 - 2015



As demonstrated by the data in Table 8 and Table 9, and the trends in Figure 9 and Figure 10, the ceiling price construct provides policymakers with a mechanism to benchmark price caps to market conditions and make course corrections over time. Through this process, Rhode Island hopes to support its dual objectives of supporting renewable energy development at a just and reasonable cost to ratepayers.

2.3.3 Key Interactions

All projects participating in the REG Program (and the DG Standard Contracts Program before it) must be qualified as Rhode Island RES *New* resources. For all non-residential customers, both DG Standard Contracts and REG Tariffs convey all energy, capacity and renewable energy certificates (RECs) to National Grid. By statute, residential customers retain all energy and capacity for self supply.[6] In all cases, National Grid owns all RECs, which it may apply towards its RES compliance obligation or liquidate into the regional market.

During the initial DG SC Pilot Program, project owners were compensated by National Grid through a PPA for all output. DG SC generators were not eligible to be net metering generators. For the REG Program, projects operating under the non-residential tariff may elect to be compensated either directly (e.g. by check) or through bill credits which resemble a form of net metering. Bill credits are provided for the lesser of the project's output or the customer's use during the billing period. Bill credits are calculated at the full value of the per kWh delivery and commodity charges applicable to their current service rate. This amount is then deducted from the full REG tariff (PBI[7]) rate, with the remaining balance (if any) paid by check. If the bill credit in a given month exceeds the PBI, the customer will receive the full amount of the bill credit (which will not exceed the total of the per kWh delivery service and standard offer charges). In other words, the customer benefits from the greater of the PBI and net metered value, but the PBI and net metering credit are not additive. Projects electing the bill credit approach must comply with all other requirements of the net metering program – including the limitation of project installed capacity to no more than 100% of the customer's three-year historic average load. All residential projects are compensated under the bill credit mechanism described above and must therefore comply with all net metering requirements. For both residential and non-residential projects, those eligible may revert to the net metering program at the conclusion of their REG tariff. Small solar projects must elect either the REG Program or the REF Grant Program. These are

[6] Energy and capacity are deemed to be consumed on-site, and are not available for sale to the utility.

[7] Performance-based incentive.

important attributes of the REG Program and unique interactions between a PBI and Net Metering Credit (RE Growth Program Public Review Meeting, 2015).

Finally, the DG SC and REG Programs also take into account the interaction between ceiling prices and federal renewable energy policy. During each year's ceiling price evaluation process, the OER and DG Board consider the federal incentives likely to be available during the following program year (for which ceiling prices are being set). When federal incentives are uncertain, the OER and DG Board may submit more than one set of ceiling prices to the PUC – reflecting, for example, pricing options with and without the Investment Tax Credit (ITC).

2.3.4 Impacts and Observations

The DG Standard Contracts Pilot Program achieved some success in attracting at least an initial burst of attention to the potential for solar development activity in Rhode Island. During the 2012 and 2013 program years, new access to utility long-term contracts, federal incentives, and robust ceiling prices spurred activity among solar developers. During this period, both smaller in-state developers and much larger regional and national developers began to establish project pipelines and submit bids to National Grid. For the larger solar categories, 2012 and 2013 solicitations were over-subscribed, and contract prices declined rapidly. Wind and anaerobic digesters have not followed this trend, receiving serious attention from only one developer each throughout the program.

The diversity of solar market participants was temporary. During 2014, market participation decreased significantly. This was likely due to a combination of factors, including: reduced margins driven by price competition (and potentially speculative bidding), the limited amount of program MWs, siting and permitting challenges, the challenge and expense of negotiating PPAs with National Grid, high or uncertain property taxes, and a greater volume of opportunities in other state markets in the region. Developers may be able to justify an unsustainable margin in order to complete an initial project and establish a market foothold, but – by definition – a viable business cannot be built in this manner. To this end, the bidding activity and price declines of 2012 and 2013 may have been, at least in part, symptoms of exuberance among less experienced developers. The degree of project attrition over time will help to determine the extent to which this may have been the case. We observe that 2014 solicitations were generally undersubscribed. By the end of 2014, the larger regional players appeared[8] to exit the market. Since the annual MW targets were allocated by technology and by size, the program as a whole fell short of its targets on numerous occasions when one or more categories were undersubscribed. This is a side-effect, and possibly a short-coming, of integrating specific diversity targets into the program.

During the first two program years (2011[9] and 2012), 16 projects totaling 15.12 MW executed Standard Contracts with National Grid. Since then, twelve (12) of these projects have become operational and four (4) projects totaling 2.15 MW (25 percent of projects and 14.21 percent of MWs) have terminated their contracts. As of the December 2014 program end date, the DG Standard Contracts Program includes 46 active contracts totaling 39.07 MW, which consist of 41 solar, 1 anaerobic digester, and 4 wind projects. No contracts were awarded to small scale hydropower. Due to the challenges presented by renewable energy permitting, financing and construction, it is reasonable to expect additional attrition. It is too early to assess an attrition rate for the remainder of active projects. Again, any MW not constructed under the Standard Contracts program will be rolled into the final 2019 solicitation under the REG Program (Renewable Energy Growth Program, 2014).

Procurement structure also has an influence on the program. While common in many markets, periodic procurements tend to foster episodic bursts in market activity rather than foster a fluid market. It is challenging to realize permanent job growth in a market that

[8] Some have speculated – although we cannot confirm this – that developers may have decided to wait for the REG program with its larger size, lower transaction costs, and hoped-for greater margins.

[9] The program initiated in 2011, which was a partial year – with one enrollment period offered in the fall.

limits the development of stable project pipelines. This may lead to frustration for project hosts and developers alike since the project development process requires ample lead time and sufficient market certainty to justify continued investment.

Overall, the Rhode Island DG SC and REG programs hold the potential to offer considerable benefits to developers through long-term, fixed price contracts for energy, capacity and RECs with a creditworthy utility. This should provide the market and revenue certainty necessary to encourage continued market investment and attract financing at reasonable costs reflective of minimized revenue risk. In addition, the REG Program's future relationship to net metering is clearly spelled out in National Grid tariffs, and distributed generation will be supported in a manner that is well-matched to distributed loads. This approach is designed to avoid over-subsidization through separate net metering and solar incentive programs.

As described, however, the program faces some challenges. Like other competitive procurement programs, competition is undermined by potentially speculative bidding and the ensuing project attrition (Wiser, O'Connell, Bolinger, Grace, & Pletka, January, 2006). While Rhode Island's small market size is undeniably a factor, these dynamics create tension in a program designed to achieve a diversity of participants, technologies and project sizes. Due to its much larger size and the current robustness and diversity of participants, Massachusetts may be able to adopt aspects of the Rhode Island program that generate certainty and developer investment without impairing the state's ability to achieve its goals for a range of market segments.

2.4 Delaware SREC Solicitation Program

2.4.1 Introduction

Delaware first implemented a state-wide renewable portfolio standard in 2005. This legislation has been revised on several occasions. Under the current policy, 25 percent of the state's electricity must be sourced from renewable energy sources in the PJM region by 2026. Unlike most other RPS states which place their RPS obligation on load-serving entities, in Delaware this obligation is placed on the state's distribution providers (Delmarva, DEC, and DEMEC).[10] As part of the state's RPS program, distribution utilities are required to source a specific portion of their renewable obligation from in-state solar installations. Utilities can fulfill this obligation either through owning their own generation or by purchasing and retiring Solar Renewable Energy Credits (SRECs). Both DMWEC and DEC have pursued a strategy of fulfilling their solar RPS requirements through self-generation. Delmarva has taken a portfolio approach to meeting its annual SREC obligations. This includes procuring SRECs through various brokerages, purchases from individually negotiated long-term contracts as well as the implementation of the SREC Solicitation Program (Delmarva Power, 2014).[11] The SREC Solicitation Program is implemented in cooperation with the Delaware Sustainable Energy Utility (SEU), a state-sponsored entity charged with developing and implementing energy efficiency and renewable energy programs and policies in Delaware.

Delaware has a restructured electricity market and is part of the 13-state PJM regional transmission organization (RTO). Delmarva power is the state's only investor owned utility (IOU), serving roughly 60 percent of Delaware's load. The Delaware Electric Co-operative (DEC) provides distribution services in the state's two southern-most counties and accounts for about 20 percent of Delaware's total load. Additionally, the state has a nine municipal utilities which are served by the Delaware Municipal Electric Co-operative (DEMEC). The SREC Solicitation Program was originally approved by the Public Services Commission in 2011 and has held annual solicitations in 2012, 2013 and 2014. Originally launched as a pilot, the solicitation program has evolved over time, with each annual solicitation having different program parameters. The overall goals of the solicitation program are to provide long-term SREC contracts to system owners, ensuring incentive price certainty while also creating a competitive landscape to limit ratepayer costs and ensure only the most cost-effective solar PV systems receive incentives.

2.4.2 Policy Description

The SREC Solicitation Program has undergone a series of changes with each annual iteration of the program. The program offers long-term contracts to PV system owners for SRECs. Contacts awarded under the solicitation program have typically had a step-down feature, with SREC prices for the first period of the contract (i.e. seven years in the most recent solicitation) awarded to system owners at the as-bid contract price and the second phase of the contract (i.e. years 8-20 in the latest program solicitation) at a pre-determined fixed rate. For the 2014 solicitation, this fixed rate was set at $35 per SREC. In the 2012 and 2013 solicitations, this price was $50 per SREC. Delmarva has not indicated a specific annual target for the percentage of its total SREC obligation it intends to procure through

[10] Municipal electricity providers and rural co-operatives are given an option to opt-out of the RPS if they develop and implement comparable renewable energy programs.

this program, although roughly 30 percent of its 2014 obligation was satisfied through SRECs procured through the program (Delmarva Power, 2014).[12]

Delmarva and its contracted program administrator[13] hold annual solicitations in which system owners bid an initial contract price for SRECs.[14] Contracts are awarded to lowest bidders first until the full volume of available credits is procured. In an effort to promote the growth of a diverse solar market that is accessible to a range of market participants, the program is divided into different solicitation tranches based on system size. The number of tranches and the relative volume of SRECs procured in each tranche has changed over the course of the annual solicitations. Additionally, the program includes tranches for both existing systems that do not currently have long-term SREC contacts, as well as new systems.[15] Table 10 shows the total number of annual SRECs procured in the 2014 solicitation (SRECDelaware, 2014).

Table 10. 2014 Delmarv Power SREC Solicitation Program Tranches

New Systems (systems with final interconnection approval after April 12th, 2013)		
Tier	**Nameplate Rating - (DC at STC)**	Annual SRECs in Tier
N-1	Less than or equal to 30 kW	3,800 Pool*
N-2	Greater than 30 kW but less than or equal to 200 kW	1,600
N-3	Greater than 200 kW but less than or equal to 2 MW	1,600
Existing Systems (systems with final interconnection approval before April 12, 2013)		
Tier	Nameplate Rating - (DC at STC)	SRECs in Tier
E-1	Less than or equal to 30 kW	3,800 Pool*
E-2	Greater than 30 kW but less than or equal to 2 MW	3,800 Pool*
* Systems in the N-1, E-1 and E-2 tiers compete for the same pool of SRECs		

For the 2014 solicitation, the two tiers for existing systems (E-1 and E-2) and the tier for smaller systems (N-1) each competed for the same pool of 3,800 annual SRECs.[16] In order to limit speculative bidding, bidders are required to provide a bid deposit of $100 per kW in order to enter the solicitation. Bid deposits are returned to solicitation entrants that are not awarded contracts or when winning bidders finish construction of their PV system. Additionally, the program applies penalties to winning bidders if the delivered volume of SRECs is substantially below the SREC volume bid by the system owner in any given year.

Table 11 below shows the range of prices bid for winning bidders as part of the 2014 solicitation. As mentioned previously, winning bidders are granted a 20-year SREC contract for the first seven years at the price bid into the auction. The remaining years of the contract are at $35 per MWh. Of note, the rules of the Delaware SREC program provide multipliers for systems that use Delaware-

[13] For the first two solicitations, the Delaware Sustainable Energy Utility (SEU) and SRECTrade jointly administrated the program. Since 2014, InClime has administered the program along with the SEU.

[14] Under the Delaware solar incentive model, system owners qualify for net metering as well as SREC-related incentives.

[15] New systems can include systems that have already reached commercial operations since the last auction or systems that are planned to begin operations within twelve months.

[16] In August 2014, the Delaware SEU launched an upfront payment program for smaller PV systems which was intended as an alternative to the SREC solicitation program.

manufactured materials and/or use Delaware sourced labor, meaning that the actual value per MWh of generation for winning bidders may up to 20 percent higher than the values shown below.[17]

Table 11. Winning Bid Pricing for the 2014 Delmarva SREC Solicitation

Tier	Low Bid	High Bid	Weighted Average Bid Price
N1, E1, E2 Pool	$0.00	$300.00	$53.44
N2 (New systems >30kW to <=200kW)	$34.46	$141.23	$88.84
N3 (New systems >200kW to <=2 MW)	$98.73	$98.73	$98.73

Prices in the three annual solicitations have generally declined over time. Table 12 and Table 13 below show weighted average winning bid prices for the 2013 and 2012 solicitations respectively. Tier sizes, contract lengths and other parameters have all changed over the course of the solicitations making direct year-over-year comparisons difficult. In the first solicitation year, smaller system sizes were awarded contracts at an administratively-set contract price with winning bidders selected through lottery. Administratively set prices are show in Table 13 for reference.

Table 12. 2013 Delmarva SREC Solicitation Prices

Tier	Weighted Avg. Bid Price
N1 (New systems <= 30kW)	$46.48
N2 (New systems >30kW to <=200kW)	$86.60
N3 (New systems >200kW to <=2 MW)	$51.13
E1 (Existing systems <= 30kW)	$34.59
E2 (Existing systems (>30kW to <= 2MW)	$39.29

Table 13. 2012 Delmarva SREC Solicitation Prices

Tier	Weighted Avg. Bid Price
Tier 1 (Administratively set, up to 50kW)	$260
Tier 2A (Administratively set, 50 to 250kW)	$240
Tier 2B (Competitive, 250 to 500kW)	$131.13
Tier 3, (Competitive, 500 to 2,000kW)	$154.35

[17] Systems using Delaware-sourced parts receive 1.1 SRECs per MWh of generation. Similarly, systems using Delaware labor receive 1.1 SRECs per MWh of generation. Systems qualifying as using both Delaware-sourced parts and Delaware labor generate 1.2 SRECs per MWh.

As the three tables show, bid prices generally declined between the 2012 and 2013 solicitations, however no obvious trend in pricing is evident between the 2013 and 2014 solicitations. This may be, in part due to the lowered later year SREC values provided to winning bidders in the 2014 solicitation.

2.4.3 Key Interactions:

Contracts awarded under the SREC Solicitation Program are one of several incentives available to Delaware PV system owners. As an alternative to the SREC Solicitation Program, the Delaware SEU recently launched an upfront payment program for smaller systems under which system owners agree to sign over all SRECs generated by their systems for a 20-year period. System owners taking part in this program cannot be awarded long-term SREC contracts under the SREC Solicitation Program.

In addition to benefitting from revenues from SREC sales, Delaware PV systems also take advantage of net metering. In the Delmarva territory, net metered systems have a 2 MW limit and qualify for full-retail rate compensation for power exported to the grid. Delaware net metering rules also allow for meter aggregation and community solar models (Delaware PSC, 2011). Table 14 below lists the average residential, commercial and industrial retail electricity rates for Delaware as of October 2014 (U.S. Energy Information Administration, 2015).

Table 14.Delmarva Power Retail Electricity Prices

Rate Type	Average Rates
Residential	14.72 cents/kWh
Commercial	10.32 cents/kWh
Industrial	7.68 cents/kWh

2.4.4 Impact and Observations

Compared to states with more aggressive solar RPS carve-outs, such as New Jersey, the Delaware renewable portfolio standard has established relatively modest near term solar energy targets. The RPS schedule requires incremental annual capacity addition in the 20 to 30 MW range each year between 2010 and 2025. These limited increasing incremental annual SREC targets, as well as Delmarva Power's existing bi-lateral SREC contracts[18] and a state-wide SREC oversupply, have limited total volumes procured under the SREC solicitation program over its first three years. In fact, the first year of the program saw the highest volume of SRECs procured, with 20-year contracts for 11,472 (estimated 8.6 MW) total SRECs/year awarded under the solicitation. The 2013 solicitation awarded long-contracts for 7,000 SRECs/year (approximately 5.2 MW) while the 2014 solicitation awarded contracts for 6,600 SRECs/year (approximately 5.0 MW). Given Delmarva's efforts to procure limited volumes of new SREC contracts every year in order to satisfy its expected obligations, and the state's relatively steady annual SREC RPS requirement, the Delaware solar market is unlikely to see major year-over-year growth in the coming years.

The SREC Solicitation program has been designed to promote market diversity. With multiple solicitation tiers for different system sizes, the program has ensured that a range of system types can participate in the program. This market diversity has increased the total number of systems installed in the state compared to a program that would support only larger systems, likely increasing total employment related to the program. Given the limited volume of SRECs procured in each annual solicitation and the even smaller number procured in each tier, market interest in some tiers for some solicitations has been limited to only a few proposed projects. The SREC Solicitation Program has driven market competition with SREC contract prices declining between the first and second

[18] Delmarva has existing bi-lateral SREC contacts with generators in the state that were signed before the creation of the SREC Solicitation Program.

solicitations. One potential concern for small solicitations is that limited participation can result in winning bidders receiving higher contact prices than would be available in a more competitive program.

A full ratepayer impact analysis is beyond the scope of this policy summary, and, given the portfolio approach taken by Delmarva, comparing the ratepayer costs related to the SREC Solicitation Program to other SRECs acquired in their compliance efforts is challenging. In its 2014 RPS compliance filing, Delmarva reported acquiring 37,214 SRECs in order to meet its RPS obligation. The reported weighted average price for these SRECs was $141.55. SRECs retired in 2014 procured during the 2012 pilot solicitation had an average reported price of $213.26 while SRECs procured during the 2013 solicitation had an average price of $45.17. SRECs procured through brokerage transactions by Delmarva for the 2014 compliance year had an average price of $62.46 suggesting that SRECs procured through the 2013 solicitation were below spot market prices during the compliance year while those from the 2012 solicitation were above spot market prices (Delmarva Power, 2014).

Total Delmarva costs related to all SRECs retired in 2014 were $5.6 million. Distributed across Delmarva's 2014 load, SREC compliance costs are less than 0.08 cents per kWh. Included in this compliance cost are $296,779 in administrative fees associated with the implementation of the SREC solicitation program. These cost are roughly 5 percent of Delmarva's total SREC compliance cost (Delmarva Power, 2014).

The Delmarva SREC Solicitation Program has promoted some market stability by procuring SRECs based on the company's expected future SREC compliance needs. This is in contrast to other RPS-based state solar incentive models where market supply and demand may become imbalanced leading to periods of over- and under-supply. Delaware's approach of placing the RPS obligation on the distribution utilities instead of its electricity suppliers also decreases the potential for boom-bust cycles as the distribution utility is able implement a compliance strategy that takes into account future obligations. While the program's annual solicitations have been relatively small, these were each tailored to the company's expected compliance needs based on the legislatively established RPS schedule.

2.5 Connecticut ZREC Program

2.5.1 Introduction

Like Massachusetts, Connecticut has a Renewable Portfolio Standard (RPS) that is assessed as a percent of total load served on all electricity providers (including competitive retail suppliers) for each of three classes. Connecticut's Class I is comparable to the Massachusetts' Class I, with some material eligibility differences. Compliance is demonstrated by the purchase and retirement of Renewable Energy Credits (RECs). Connecticut's RPS ramps up to 20 percent by 2020 for Class I RECs, which includes production from biomass (with some emissions restrictions), small hydroelectric, wind, tidal, and solar photovoltaic plants, generally without a vintage threshold. There is an Alternative Compliance Payment (ACP) of $55/MWh which serves as a price cap.

The Class I obligation has typically been served by out-of-state generation, and mostly by legacy biomass and landfill gas generators due to the lack of a vintage requirement. The Connecticut Zero-Emissions Renewable Energy Credit, or ZREC, program is a long-term contracting program for Class I RECs designed to incentivize the development of distributed generation resources in the state (CT PURA, 2011). It is worth clarifying that while all RECs generated under the ZREC program are used to offset Class I REC obligations, the ZREC program is not a specific carve-out of the Class-I market, as with the Mass. SREC market. The ZREC program was introduced as a part of suite of programs through Public Act 11-80, passed in July 2011 (State of Connecticut, 2011). Given the lack of in-state wind potential, the main focus of the programs was solar and fuel cell projects. These programs complement recent long-term contracting efforts that have selected new, regional wind resources to contribute to the state's Class I REC supply.

In Connecticut, there are only two Electric Distribution Companies (EDCs) – Connecticut Light and Power (CL&P) and United Illuminating Company (UI). These companies carry about one-third of the RPS obligation, with the rest being borne by competitive retail suppliers. The Connecticut Public Utilities Regulatory Authority (CT PURA), formerly known as the DPUC, administers the LREC/ZREC program and only has the authority to direct EDCs to participate in long-term contracting programs. Thus, UI and CL&P carry the full burden of the state's goals for distributed generation.

2.5.2 Policy Details

The ZREC program was established in conjunction with the Low-Emissions Renewable Energy Credit, or LREC, Program in 2011 pursuant to Sections 107, 108 and 110 of Public Act No. 11-80 (State of Connecticut, 2011). Implementation has occurred under the auspices of the CT PURA. The intention of this program is to incentivize the development of distributed generation in the state of Connecticut. The ZREC program is open to wind, solar and small hydroelectric projects up to 1 MW, while the LREC program is open to all of the above, along with natural gas fuel cells, landfill gas, and biomass gasification units up to 2 MW. Both programs offer 15-year fixed price contracts with the state's electric distribution companies (EDCs) for RECs, all of which are Class-I eligible (CT PURA, 2011).

The ZREC program is operated on a fixed-budget basis, with the two EDCS offering $8 million of new contracts once per year for six years, beginning in 2012. The LREC program has an additional $4 million of annual contract budget. It is important to note that this budget reflects the single-year contracted amount. Thus, at its peak, the ZREC program would cost $48 million per year (See Figure 11 for illustration of expense schedule). The total program budget is divided between the EDCs based on their respective share of total load served – 80 percent for CL&P and 20 percent for UI. The ZREC program (and its budget) is also divided by size categories.

Figure 11. LREC/ZREC Program Expenses Illustration
(The Connecticut Light and Power Company and the United Illuminating Company, 2011)

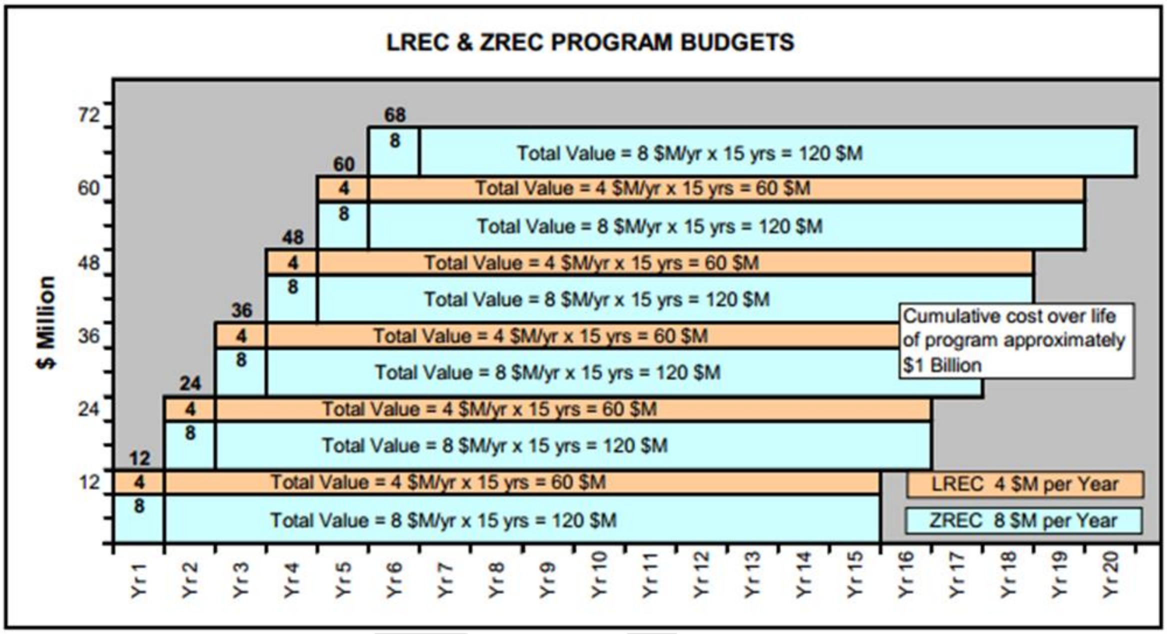


Table 15. Project Size Definitions and Annual Contract Budget

ZREC Project Category	Capacity Range	Total Solicitation Budget (UI & CL&P)	
		UI	CL&P
Small	0-100 kW AC	$0.533 M	$2.133 M
Medium	100-250 kW AC	$0.533 M	$2.133 M
Large	250-1000 kW AC	$0.533 M	$2.133 M

Each year, the EDCs offer a single, simultaneous solicitation for projects in their territory. The solicitation is limited to the Medium and Large ZREC categories, which are selected on a least-cost basis. Bids are evaluated for each EDC separately, and projects are awarded contracts as-bid until the full budget is exhausted or there are no more applications. The only exception to the least-cost provision is for projects including technologies researched, developed or manufactured in-state. These projects are assessed at a cost 10 percent below their actual bid price. The Small ZREC program is administered as a fixed price tariff program with a competitively-derived price set at 110 percent of the weighted average bid price of selected Medium ZREC projects. These projects are selected on a rolling admissions basis, with tie-breaking procedures in place for rounds in which the program is oversubscribed on the first day.

The price cap for all sectors of the ZREC program is $350/REC in Round 1 and decreasing by round over time. Each year, CT PURA may lower the program cost cap by 3-7 percent according to multiple factors including actual bid prices from the previous year and expected changes in installed costs (The Connecticut Light and Power Company and the United Illuminating Company, 2011). Across all sectors, projects will be notified if and when their bid has been selected, at which point the applicant must execute a contract with the applicable company and submit the required performance assurance. This deposit is equal to a percentage of the maximum annual quantity of ZRECs multiplied by the contract price. This percentage is 20 percent for Large ZREC projects, 10 percent for Medium, and 5 percent for the Small ZREC category (The Connecticut Light and Power Company and the United Illuminating Company, 2011). Projects may also opt to terminate their application at this time, in which case a contract will be offered to the next projects (or projects) in the queue for which budget is available. In any year where the full budget is not utilized, the EDC may be directed to hold an additional solicitation, and/or shift budget between size categories to ensure that the program's funds are fully utilized. Excess budget may also be rolled into future years' solicitations.

Once a project's contract is executed, it has until its contracted Delivery Term Start Date plus a 12-month grace period to reach commercial operation. This provides a roughly two-year development window. Regardless of the project's actual online date, its 15-year contract term will begin on the Delivery Term Start Date. The relatively long development window has both benefits and drawbacks, as it gives projects an appropriate amount of time to reach commercial operation, but does not regularly clear out undeveloped projects. This results in long delays in budget reconciliation and capacity recycling into future rounds.

Rounds 1 and 2 both attracted sufficient bids such that the full budget could be allocated for each market segment in a single solicitation. In each round, minor adjustments were made to shift budget between sectors such that surpluses could be pooled to accommodate an additional project or projects. All of these adjustments require PURA approval. Any remaining budget surpluses are rolled into the following year's solicitation. Round 3 was the first round in which a program sector was undersubscribed due to front-end attrition of projects. In this case, an additional solicitation was held to fully contract the budgeted amount.

Table 16. Total and Accepted Number of Bids by EDC and Round

Program Category	EDC	Round 1		Round 2		Round 3	
		Total	Accepted	Total	Accepted	Total	Accepted
Large ZREC	CL&P	140	21	52	19	78	32
	UI	22	6	12	4	8	8
	Total	**162**	**27**	**64**	**23**	**86**	**40**
Medium ZREC	CL&P	113	47	157	70	113	95
	UI	37	13	35	24	50*	27*
	Total	**150**	**60**	**192**	**94**	**163**	**122**
Small ZREC**	CL&P	484	214	460	277	N/A	N/A
	UI	107	31	108	51	N/A	N/A
	Total	**591**	**245**	**568**	**328**	N/A	N/A

**After receiving insufficient interest in the first solicitation, UI was directed by CT PURA to re-open the Medium ZREC solicitation to additional bids. This total reflects the additional applications received during that process.*

*** CL&P's "accepted" numbers represent projects with executed contracts. UIs are noted as "Selected". May not be consistent.*

Table 17. Total and Accepted Capacity (MW) of Bids by EDC and Round

Program Category	EDC	Round 1		Round 2		Round 3	
		Total	Accepted	Total	Accepted	Total	Accepted
Large ZREC	CL&P	94.3	12.2	34.2	12.2	65.3	27.6
	UI	12.1	2.6	7.2	2.4	5.9	5.9
	Total	**106.4**	**14.8**	**39.4**	**14.6**	**75.0**	**32.7**
Medium ZREC	CL&P	21.5	8.8	30.2	14.2	24.5	18.1
	UI	7.1	2.5	6.4	4.4	9.7*	5.1*
	Total	**28.6**	**11.3**	**36.6**	**18.6**	**30.4**	**24.0**
Small ZREC	CL&P	22.0	9.2	23.3	13.4	N/A	N/A
	UI	6.7	2.3	6.2	2.9	N/A	N/A
	Total	**28.7**	**11.5**	**29.5**	**16.1**	N/A	N/A

**After receiving insufficient interest in the first solicitation, UI was directed by CT PURA to re-open the Medium ZREC solicitation to additional bids. This total reflects the additional capacity contracted during that process.*

The program has been successful in attracting bids at prices below those for SRECs on the spot market in neighboring Massachusetts. The results of each solicitation to date are summarized in the table below. This data presents only the average bid price for selected projects. Though individual bid prices are protected, it is clear that the range of bid prices has narrowed considerably over time. In Round 1, the average price of selected bids came in $30-40/MWh less than the average price of all bids. By Round 3, this gap dropped to $0-10. This could signal developers generally providing more competitive bid prices or the more expensive developers falling out of the market.

Table 18. Weighted Average Prices of Selected Bids for ZREC Program
(Calculated Tariff Price for Small ZREC Category)

Program Category	EDC	Round 1	Round 2	Round 3
Large ZREC	CL&P Weighted Average	$101.36	$76.63	$59.35
	UI Weighted Average	$117.27	$90.43	$65.76
	Total Weighted Average	**$104.13**	**$78.87**	**$60.48**
Medium ZREC	CL&P Weighted Average	$149.29	$93.65	$73.61
	UI Weighted Average	$135.36	$102.31	$76.40
	Total Weighted Average	**$146.23**	**$95.70**	**$74.22**
Small ZREC	CL&P Calculated Price	$164.22	$103.01	$80.97
	UI Calculated Price	$148.89	$112.54	$84.04
	Average Calculated Price	**$161.15**	**$104.92**	**$81.59**

2.5.3 Key Interactions

The ZREC program differs from some renewables contracting programs in that the EDCs are only contracting the RECs associated with production, and that energy and capacity are not included in the transaction. As a result, ZREC premiums are directly dependent on the current and projected value of electricity and capacity in Connecticut, as well as the availability of virtual net metering for larger projects. Currently, virtual net metering is only permitted for public off-takers, a much more restrictive environment than exists in Massachusetts. For all other projects, the energy must be used on-site, limiting the number of potential hosts.

The ZREC market also interacts (to a limited extent) with the LREC market and the broader Class I Renewable Energy Credit market. Although solar is eligible to participate in both of these markets, the price of RECs in both is well below that of ZRECs and is likely to stay that way for the duration of the program. In theory, if the program was extended to the point at which solar reached parity with LREC or other Class I resources, LREC and ZREC prices would converge at a level below Class I prices, reflecting the financing benefits of a long-term contract, and solar projects up to 2 MW would have access to this mechanisms through LRECs.

2.5.4 Impacts and Observations

To date, there have been three rounds of solicitations under the ZREC program. The program has attracted a large number of bids across all sectors. To date, almost all of the ZREC bids (both offered and selected) have been solar photovoltaic projects.[19] Selected bids are diverse in terms of project size, with projects falling across the range of eligibility for each category.

Reviewing the list of participating project developers, the Connecticut ZREC market appears very similar to the Massachusetts market with a mix of local and national developers. The detailed bid data for Round 3 has not been released yet, so it is premature to speculate on trends over time, but it appears that a healthy level of diversity is present in the market. Similarly, anecdotal evidence suggests that both municipalities and private houses are engaging in offtake agreements. This data is not published, making it difficult to speculate on how this has changed over time.

In total, between 400 and 450 MW of solar is expected to be contracted and built through the ZREC program, with all projects online by 2019. This results in a peak installation rate of roughly 100 MW/year from 2015-2017. Broken down by sector, the ZREC program should support roughly 125 MW of small solar (<100 kW), 150 MW of medium projects (100-250 kW) and 160 MW of large projects (>250 kW). Contracted capacity in the 2015 and 2016 solicitations is expected to continue to increase as bid prices fall, with a contraction in 2017 after the expiration of the ITC. This volatility is one of the side effects of a fixed-budget program, and could be disruptive to developers attempting to ride out an already difficult time in the market.

What is not reflected in any of the tables above is the rate of success for executing contracts with selected projects, and the additional fallout of projects for which contracts have been executed. There have been substantial front-end withdrawals across all sectors, detailed in Table 19 below. It is interesting to note that while front-end attrition for Large ZREC projects dropped significantly following the first round, they have stayed relatively constant for Medium projects and jumped substantially from Round 1 to Round 2 for small projects. Broadly speaking, however, roughly 35 percent of the ultimately contracted capacity dropped out pre-commitment over the course of the first three rounds for CL&P, with this figure dropping in successive rounds from 68 percent to 26 percent to 19 percent. The first round appears to be an outlier – anecdotal evidence suggests that a number of developers jumped in without fully understanding net metering rules or other constraints and pulled out as they learned their projects would not be financially viable; the next two rounds may be more indicative. This dynamic suggests that some speculative bidding has taken place, or perhaps more accurately, that the single procurement per year cycle forces submission of some bids that are insufficiently vetted. However, it also suggests that the performance assurance requirements are somewhat effective in shaking out untenable projects from the program early, clearing space for projects willing to provide performance assurance.

[19] Four small hydro projects were selected in Round 2 and two were selected in Round 3. In Round 1, three small hydro projects and two wind projects bid into the solicitation and were not selected. The industry as a whole expects these technologies to play little if any role in future solicitations.

Table 19. Front-End Attrition Rates for CL&P ZREC Solicitations[20]

Event	Category	# Bid/ Applied	MW	Withdrawn After Selected	MW	# Fully Executed	MW
Year 1 RFP	Large ZREC	140	94.3	22	16.7	21	12.2
	Medium ZREC	113	21.5	13	2.4	47	8.8
	Small ZREC	484	22.0	33	1.5	214	9.2
Year 2 RFP	Large ZREC	52	34.2	4	3.2	19	12.3
	Medium ZREC	157	30.2	13	2.5	70	14.2
	Small ZREC	460	23.3	85	4.6	277	13.4
Year 3 RFP	Large ZREC	78	65.3	7	5.8	32	27.6
	Medium ZREC	113	21.5	14	2.7	95	18.1

To further examine the issue of speculative bidding, it is important to look at a number of other factors. First, the early rounds of the program have been plagued by long delays and high attrition rates among projects with executed contracts. The table below summarizes terminations and in-service delays for Connecticut Light and Power, which carries 80 percent of the program obligation. Round 1 saw roughly 25 percent of Medium and Large projects ultimately terminate their contracts, with four projects still not yet online. So far, attrition rates are much lower for Round 2, but with the majority of projects still not operational, the number of terminations here is likely to increase, perhaps substantially.

Table 20. LREC/ZREC Solicitation Performance – CL&P Contracts from Rounds 1 and 2[21]

Event	Category	Applied		Fully Executed		Active		Terminated		In-Service		Pending	
		#	MW	#	MW	#	MW	#	MW	#	MW	#	MW
Round 1	Large ZREC	140	94.3	21	12.2	13	8.2	8	4.0	12	6.3	1	1.9
	Medium ZREC	113	21.5	47	8.8	31	5.4	16	3.4	30	5.0	1	0.4
	Small ZREC	484	22.0	214	9.2	180	7.6	34	1.6	115	3.5	65	4.1
Round 2	Large ZREC	52	34.2	19	12.3	18	11.4	1	0.9	3	1.4	15	10
	Medium ZREC	157	30.2	70	14.2	68	13.8	2	0.4	25	4.7	43	9.1
	Small ZREC	460	23.3	277	13.4	275	13.3	2	0.1	35	0.6	240	12.7

To estimate the number of ultimately successful projects, one can apply an assumed rate of success to the pending projects listed in the table above. In Table 21 below, we estimate a total attrition rate assuming that that the historical attrition rates serve as a proxy for the attrition from the pending capacity.[22] This calculation is made and applied by round and sector.

[20] Data summary provided by Northeast Utilities January 27, 2015.

[21] Data summary provided by Northeast Utilities January 27, 2015.

[22] Percent attrition for pending projects equals the quantity of terminations divided by the sum of terminations and operating projects (i.e., projects that have reached a definitive end-point).

Table 21. Assumed Total Capacity Reaching Commercial Operation: CL&P Rounds 1 and 2[23]

Event	Category	Fully Executed		Projects Currently Operating		Assumed to Reach Comm. Operation		Assumed % Reaching Comm. Operation	
		#	MW	#	MW	#	MW	#	MW
Round 1	Large ZREC	21	12.2	12	6.3	13	7.5	60%	61%
	Medium ZREC	47	8.8	30	5.0	31	5.2	65%	60%
	Small ZREC	214	9.2	115	3.5	165	6.3	77%	69%
Round 2	Large ZREC	19	12.3	3	1.4	14	7.5	75%	61%
	Medium ZREC	70	14.2	25	4.7	65	13.1	93%	92%
	Small ZREC	277	13.4	35	0.6	262	11.5	95%	86%

Clearly, the attrition rates in Round 2 are well below those in Round 1 for most categories. However, using the methodology described above, one could expect more than 1/3 of the total capacity entering into Large ZREC contracts to fail to reach completion. To address the overall project attrition issue, CT PURA recently revised the program rules to discourage speculative bidding and encourage voluntary self-policing of the project pipeline. These changes move up the timeline for performance assurance delivery, require an affidavit from the land-owner acknowledging an agreement with a single project (to prevent multiple bids per site), and provide a 20 percent performance assurance refund for projects that voluntarily terminate before the required in-service date.

To help understand whether the reported weighted average price of selected bids is indicative of successful project prices, or whether speculative bidding causes disproportionate dropout of lowest bids, we examined the weighted average bid price for projects that have not yet dropped out compared to the average across the full pool of executed contracts. If speculative bidding was a pervasive problem that distorts the reliability of selected price data, one would expect that the weighted average price of completed projects would be higher than the weighted average across all selected projects. Table 22 below provides this comparison for the CL&P bids and contracts awarded in the first two rounds of the program.

[23] Data summary provided by Northeast Utilities January 27, 2015.

Table 22. Weighted Average Bid Prices for All, Selected and Completed CL&P Projects[24]

Event	Category	Weighted Average BID price/REC	Weighted Average Price/ REC for all selected projects	Weighted Average Price/REC for 'active' projects[25]
Year 1 RFP	Large ZREC	$138.03	$101.36	$104.13
	Medium ZREC	$179.85	$149.29	$146.83
	Small ZREC	$164.22	$164.22	$164.22
Year 2 RFP	Large ZREC	$87.86	$76.63	$83.49
	Medium ZREC	$106.75	$93.65	$88.85
	Small ZREC	$103.01	$103.01	$103.01

The current snapshot data above – which is incomplete, since additional attrition is expected - reveals that for Large ZREC projects, the weighted average price of completed projects is, in fact, higher than that of the full selected bid pool. For the Medium ZREC category, the opposite is true. A possible explanation for this is that while some speculative bidding may be taking place among larger projects, the diversity of sites and associated challenges for medium projects creates an environment in which bid price is not the primary driver of project success or failure. This metric will be worth watching as the pending projects move to either completion or termination, to get a more complete picture of the true prices yielded by the program.

Based on participation (both in number and prices of bids) in Round 3, it appears the race to the bottom has slowed considerably, though it is unclear if this is a result of the program maturing or of the new rules propagated by CT PURA. In general, the level of competition is dropping noticeably from round to round. While it is difficult to draw definitive conclusions, this could be due to either saturation of good solar sites (i.e. independent of the incentive mechanism) or competitors leaving the market (perhaps due to the insufficient margins, a direct result of the incentive mechanism). It is worth highlighting that Round 3 is the first round in which additional solicitations were required for any category, a significant departure from the oversubscription of the previous two rounds. Looking ahead, there are three additional procurements planned for 2015, 2016 and 2017. It is likely that attrition from early rounds of the program will shift additional budget into these procurements, and that an additional year (or more) of solicitations may be required to fully spend the committed funds. This budget shift may also help to offset the higher bid prices expected in 2017 following the expected loss of ITC and preserve a smoother annual installed capacity trend.

It is our expectation that regardless of the availability of the ITC, ZRECs will continue to be priced well above Class I RECs. Whether EDCs choose to retire ZRECs to meet their own Class I REC obligations or resell them into the market, the companies are allowed to recover the full costs of the program from distribution ratepayers. While the RECs are purchased at above-market prices, the program does promote the development of in-state resources, which is largely absent from the broader Class I market. With this comes in-state jobs and other indirect economic benefits, reliability benefits, and fuel diversity for Connecticut ratepayers. The competitive procurement approach seeks to achieve this suite of benefits at the lowest possible cost to ratepayers. The fixed income stream provides more certainty to projects trying to secure financing, and ultimately driving a lower cost of capital and lower total development cost. This is why, at the surface, the ZREC program appears to drive development at a cost well below that of market-based programs like the Massachusetts SREC markets.

It is unclear whether the attrition that has occurred in the market to date has been at the bottom of the cost stack, such that the weighted average bid cost represents an artificially low program cost, but we expect the EDCs to release analysis of this issue in the

[24] Data summary provided by Northeast Utilities January 27, 2015.

[25] Active projects are competed and pending.

near future. There are likely some less obvious economic impacts associated with the competitive procurement approach particularly one with infrequent solicitations. In contrast to procurement mandates, such as RPS tiers or standard offers, which allow for a relatively steady stream of sales, design, financing and installation workflow that is conducive to establishing long-term jobs, episodic procurements represent bursts of activity that are difficult to staff for, often leading to short-term jobs and greater use of mobile labor.

2.5.5 Summary Observations and Lessons Learned

In its first three rounds of procurements, the ZREC program has successfully contracted for the full budgeted amount for both EDCs (although Round 3 required a second solicitation in some categories), almost all of which has been for solar PV projects. Similarly, the Small ZREC procurement has been heavily oversubscribed at the fixed price in both of the first two rounds. All of these contracts have come at rates well below spot prices for SRECs in Massachusetts. However, there are additional complexities.

First, the ZREC program contracts project RECs for 15 years, compared to the 10-year eligibility of an SREC II project. Thus, the EDCs are paying above-market rates for Class I RECs for an additional five years. It is also not clear that the market can actually support robust development at the prices that have been offered to date. The single procurement per year fosters an environment of speculative bidding, with developers hoping the economics pencil out before the development window closes. Low commitment hurdles and collateral requirements do little to prevent this behavior. While the EDCs argue that the single procurement is necessary to control the administrative costs of the program, the market has already seen long delays and high attrition rates from projects selected in the first two rounds. Municipalities have also countered the administrative cost claims with complaints that the current system often results in a great deal of effort being put into projects that are ultimately not selected and shelved for another year (if ever revived). The state has promulgated rules to help limit attrition and reduce termination lag time, but it remains to be seen how effective this will be. It seems very unlikely that the measures will address the issues raised by municipalities.

Ultimately, the shortfalls of Connecticut's ZREC program could potentially be avoided in Massachusetts if addressed from the beginning. As a larger market, there should be more opportunities in Massachusetts for more regular solicitations, and requiring higher development hurdles for bidders is simply a matter of policy design. If done correctly, it is reasonable to believe that enacting a program similar to the LREC/ZREC program in Massachusetts could achieve similar levels of development at a lower cost to ratepayers and with greater certainty for developers than the SREC market structure currently offers.

2.6 New Jersey Electric Distribution Company Contracting, Direct Ownership and Financing Programs

2.6.1 Introduction

New Jersey has consistently had one of the most robust state solar markets in the United States. This market growth has been driven by a succession of policies over the past several years, from a series of rebate programs in the latter part of the last decade to the current solar carve-out in the state's renewable portfolio standard (RPS). The current state-wide renewable goal is 17.88 percent by 2021 while the current RPS requires 4.1 percent to the state's retail electricity to come from in-state solar by 2028 (Assembly, New Jersey State and General, 2012). This compliance obligation, and the annual schedule to reach it, have changed on several occasions over the past years through legislative action in response to greater than anticipated solar market growth causing SREC market price volatility.

As with several other East-coast states with large solar markets, New Jersey has a deregulated energy market and participates in the PJM Regional Transmission Organization. The states has four investor owned utilities, Public Service Electric & Gas (PSE&G), Rockland Electric Company (RECO), Jersey Central Power & Light (JCP&L) and Atlantic City Electric (ACE). Of these, PSE&G is the largest electric distribution company in the state, supplying a little over 50 percent of the state's load in 2012 (State of New Jersey, Board of Public Utilities, 2009).

Unlike the Massachusetts SREC market, the New Jersey market obligation is legislatively fixed and does not include an SREC price floor. This has, in part, contributed to significant market volatility (in terms of both the pace of development and SREC price) and SREC incentive price uncertainty for project owners. During the state's transition from a rebate-based market to an SREC solar incentive market model, the New Jersey Board of Public Utilities (NJBPU) convened a stakeholder process to explore programmatic methods for supporting solar financing within the SREC market model. At the time, there was concern that an SREC market model without predictable cash flows from SREC sales would hinder market development as project developers would be unable to secure adequate financing. In response to these concerns, three utility-sponsored programs were developed to ensure some portion of New Jersey solar installations would benefit from long-term SREC price certainty. (State of New Jersey, Board of Public Utilities, 2009) These are:

- The PSE&G Solar4All initiative
- The PSE&G solar financing initiatives
- The ACE, RECO and JCP&L long-term solar contracting programs

These ancillary programs are the focus of this policy brief.

2.6.2 Policy Description

2.6.2.1 Solar4All Program

The Solar4All program is a direct utility solar ownership program implemented by PSE&G. This initiative was originally approved in July 2009 and allows PSE&G to procure 80 MW of solar on brownfields, grayfields, and urban enterprise zones. The program also authorized installation of PV on company-owned utility poles (State of New Jersey, Board of Public Utilities, 2009). The second iteration of Solar 4All was approved by the New Jersey Board of Public Utilities in May of 2013. This phase of the program is focused on utility ownership of PV systems on underutilized land such as brownfields and landfills as well as implementation of pilot tranches of utility-owned PV designed for electricity system resiliency, underutilized government facilities and parking lot applications. Table 23 below shows the expected total MW of PV installed and owned by PSE&G in the Solar4All Extension program.

Table 23. PSE&G Solar4All

Market Segment	Total Solar4All Extension MW
Landfills and Brownfields	42 MW
Underutilized Government Facilities	1 MW
Grid Security/Storm Preparedness	1 MW
Innovative Parking Lot Applications	1 MW

PSE&G recovers its investment in the Solar4All program as it would other utility infrastructure investments and by selling energy generated by Solar4All systems into the market. Any revenue from sale of energy or SRECs from the systems are refunded to ratepayers through reductions in the company's overall Solar4All cost recovery mechanism. In its most recent program filings with the NJBPU, PSE&G argued that the program promoted a number of key public policy goals including:

- Solar development on otherwise unused brownfields and landfills;
- In-state job creation;
- Assist with the development of a market for new solar applications. (State of New Jersey, Board of Public Utilities, 2013)

The Solar4All extension program has also been structured in order to help alleviate potential SREC market oversupply. As part of the stipulation authorizing the initiative, PSE&G agreed to stagger system installations over several years in order to prevent market oversupply that could significantly decrease SREC market prices (Belden, Michaelman, Grace, & Wright, 2014). The structure of this program may help support market stability in future years by providing ongoing market support during times of limited market activity or by reducing market SREC supply during oversupply conditions. Additionally, the competitive nature of the utility solicitations for each solar installation may support state-wide goals of lowering overall SREC compliance costs. An initial analysis concluded that, once completed, that program would increase annual ratepayer costs by an average of 0.329 percent (State of New Jersey, Board of Public Utilities, 2013).

2.6.2.2 PSE&G Solar Loan Program

In addition to operating the Solar4All program, PSE&G has implemented a series of solar financing initiatives. Currently in the third iteration of the program, the Solar Loan III Program provides participating PV system owners with the ability to finance a portion of the upfront cost of their systems and repay the debt with SRECs at a predetermined price. PSE&G has been authorized to provide loans for 97.5 MW of PV under the latest program funding round. In an effort to promote market diversity, this capacity is allocated to four project types:

- Large non-residential systems (>150kW <= 2 MW);
- Small non-residential systems (<= 150kW);
- Residential systems;
- Aggregations of residential systems;
- Landfills and Brownfields (<= 5MW).

PSE&G conducts regular solicitations (four to six times a year) in which system owners bid an SREC floor price into a competitive solicitation. This floor price is the minimum value that SRECs transferred to PSE&G will receive to pay off the solar program loan. If market prices for SRECs should increase above the awarded system floor price, SRECs transferred to PSE&G will be monetized at the higher market price, allowing system owners to pay back their loans more quickly. Systems which bid the lowest floor prices are awarded loans until the available capacity for the solicitation round has been fully allocated. Solar loans for the program have a 10-year tenor and a fixed interest rate of 11.179 percent. Administrative fees associated with the costs of the program are paid by winning bidders and incorporated into the total loan amount.

Most solicitation tranches under the Solar Loan III Program have been undersubscribed with the notable exception of the Landfill and Brownfield market segments during the first two rounds of the program. Table 24 below lists the weighted average SREC floor price for winning bidders for the first five Solar Loan III Program rounds. The first solicitation took place in late 2013 with the fifth solicitation awarding contracts in December 2014.

Table 24. Solar Loan III Average Weighted SREC Prices

System Size	Solicitation #1	Solicitation #2	Solicitation #3	Solicitation #4	Solicitation #5
Large non-residential systems (>150kW <= 2 MW)	$177	$205	$209	$195	$195
Small non-residential systems (<= 150kW)	$235	N/A	$256	$230	$245
Residential systems	$258	$262	$275	$274	$276
Aggregations of residential systems	N/A	N/A	$214	$214	N/A
Landfills and Brownfields (<=5MW)	N/A	$188	N/A	N/A	N/A

Once transferred to PSE&G, SRECs are sold into the market and revenues from these sales are used to offset program costs. Any costs associated with the program not recouped by PSE&G directly from program participants are recovered through the state's RGGI surcharge mechanism (State of New Jersey, Board of Public Utilities, 2013). In its filings, PSE&G estimated that the average non-participating ratepayer would see a maximum bill increase of $2.12 annually due to the Solar Loan III Program.

Average prices in the Solar Loan III Program have not decreased over the course of the program and have been significantly higher than publicly available SREC spot market prices (SRECTrade, 2015). Additionally, most of the solicitation tranches have been consistently under-subscribed, potentially due to the relatively high interest rates offered.

2.6.2.3 EDC Solicitation Programs:

As part of initial efforts to support financing availability for solar PV projects participating in the state's SREC market, ACE, JCP&L and RECO proposed to jointly implement a long-term SREC contracting program. The first iteration of this program was launched in August of 2009. Under this first-phase program, the participating utilities held eight coordinated solicitations over a two-year period. Solicitation participants bid SREC prices for long-term purchase contracts (10-15 years). In order to support market diversity, the program had solicitation tiers for small systems (0-50kW), medium sized systems (50-500kW) and large systems (0.5-2MW). (New Jersey Economic Development Corporation, 2011). Winning solicitation bidders were awarded contracts based on as-bid prices. As SRECs were generated, the distribution companies pooled SRECs obtained through the program with SRECs from the PSE&G initiatives (see above) and sold them into the market on a quarterly basis.

In the first phase of the program, ACE, JCP&L and RECO signed long-term SREC contracts totaling 63.4 MW. Average contracted SREC prices ranged from a high of $460 per MWh to $232 per MWh. (Rutgers Center for Energy, 2012). Table 25 below shows the weighted average SREC price for solicitations in each of the utility territories by year.

Table 25. Weighted Average SREC Price (2010 – 2012)

Energy Year	ACE	JCP&L	RECO
2010	$373	$407	$460
2011	$425	$423	$384
2012	$253	$232	$380

As part of extended efforts to reduce market price volatility and support long-term financing for PV systems, the NJBPU authorized a second phase of this solicitation program in May of 2012. This program will launch in 2015 and will have a similar structure to the earlier program. The total expected capacity procured through the new initiative is 180MW over a three-year period and, as with previous program iteration, the solicitations will have separate tiers to help promote market diversity (State of New Jersey, Board of Public Utilities, 2013).

2.6.3 Key Interactions

The ancillary policies discussed in this profile exist within the framework of the New Jersey solar RPS carve out. Additionally, solar PV systems in New Jersey typically qualify for net metering, although some larger PV systems in the state sell power directly into the PJM wholesale market. These 'grid-supply' projects were a major driver of market growth, but recent legislation has moved to cap development in this market segment and require NJBPU approval for project through a first-in-time approval process.[26] State net metering laws allow for single-customer meter aggregation for government entities, but do not support broader virtual net metering.

2.6.4 Impact and Observations

New Jersey has consistently had one of the largest solar PV markets in the United States over the past several years. This market has been driven largely by the state's solar carve out in its renewable portfolio standard. The ancillary policies discussed in this section have supported public policy priorities related to the state's solar market including creating long-term price certainty for a segment of the state's PV system owners and increasing state solar capacity through utility-owned PV systems. These programs, through regular procurements, have helped foster market stability and have been coordinated to ensure that they do not promote SREC market price volatility. It should be noted, however, that the New Jersey solar market has experienced periods of volatility, particularly in late 2011 and early 2012 when the market grew rapidly as developers attempted to secure expiring federal incentives while taking advantage of high expected future SREC values. (Belden, Michaelman, Grace, & Wright, 2014)

Market interest for these ancillary programs has been mixed, with some program solicitations being oversubscribed while others have received limited market interest. For instance, the market response to the latest iteration of the PSE&G loan programs has been less competitive in some market categories than others. A full analysis of the drivers behind this market dynamic is beyond the scope of this summary, however the complexity of the program as well as the relatively high interest rate (11.179 percent) may serve to limit participant interest, particularly amongst less sophisticated prospective residential PV owners.

Each of the three policies of interest have competitive aspects that promote incentivizing least-cost systems. Systems installed through the PSE&G direct ownership program are purchased through a competitive procurement process. Similarly, both long-term contracting programs conduct regular competitive solicitations, awarding contracts to the most competitive bids. Additionally, the latest iteration of the PSE&G solar loan program includes a competitive component that awards long-term SREC contracts on a competitive basis. As with all competitive procurement programs, some proportion of systems that have been awarded contracts will not be built. This can happen for a number of reasons, from developers bidding overly aggressively in order to win contracts to technical issues that were unknown at the time of the solicitation. Contract failure rates for the programs discussed in this profile are not available, however this concern is worth further exploring if Massachusetts policymakers move forward with similar competitive bidding programs.

The New Jersey EDCs aggregate and re-sell the SRECs procured through these programs on a quarterly basis through a market auction mechanism. Proceeds from this auction are applied to the costs of the program, lowering the overall ratepayer cost for these initiatives. During periods when the auction price is above the average price paid by through the EDC programs, ratepayers may see a net benefit on their bills. During periods when the auction prices are lower than the average contract prices, these programs would add costs to the distribution portion of a ratepayer's bills. In accounting for the costs and benefits of these programs, it is critical to remember that ratepayers ultimately pay the costs of supplier RPS compliance, meaning that any savings seen on the distribution

[26] This market regulation is analogous to the "Managed Growth" market segment in the Massachusetts SREC II program.

portion of ratepayer's bill due to high SREC prices attained in the auction may be reduced through higher supplier RPS compliance costs.

The ancillary policies described herein support the New Jersey SREC market by promoting long-term incentive price certainty and creating a utility-supported sub-market. These programs have helped moderate potential solar market volatility in New Jersey. The competitive nature of both the utility long-term contracting programs and the PSE&G financing program have established incentive levels through price competition. Two of these three ancillary policy mechanisms have analogues in the current Massachusetts solar market framework, with Massachusetts EDCs able to own their own solar generation and the pending solar MassCEC/DOER supported residential solar loan programs.[27] Similarly, the price floor mechanism in the Massachusetts SREC market is intended to create long-term SREC price certainty, a goal of the New Jersey EDC long-term contracting program.

[27] Additionally, the Massachusetts Section 83A long-term contracting program within the Class I market has similarities to the New Jersey EDC solicitation programs.

2.7 Vermont SPEED Standard Offer

2.7.1 Introduction

Vermont established the Sustainably Priced Energy Enterprise Development (SPEED) Standard Offer Program to encourage the development of, and enable financing for, renewable energy distributed generation in the state. Through the SPEED Standard Offer Program, Vermont provides long-term contracts of between 15 and 25 years, depending on the technology, to qualifying renewable energy generators less than or equal to 2.2 MW. Initially, contracts were awarded at an administratively-determined, fixed, standard offer price, akin to a feed-in tariff. Subsequent program changes converted the program to one in which contracts are awarded through a competitive bidding process (subject to a price cap). While Standard Offer remains in the program name, it remains a competitive process. The SPEED Standard Offer Program operates under the jurisdiction of the Public Service Board (PSB). The Vermont Electric Power Producers Inc. (VEPP Inc.) was selected as the program facilitator, and is responsible for both managing competitive procurements and administering the contract payments and collections through the state's utilities. The program began in 2009 with a 50 MW target and now includes legislative authority for up to 127.5 MW of contracts with solar, wind, biomass, landfill gas, farm methane, and hydroelectric generators by 2022. The SPEED Standard Offer program has created an active market for distributed generation in Vermont (Vermont SPEED Homepage, 2015).

VEPP Inc. began accepting applications for the initial 50 MW target in October 2009. The PSB implemented a lottery to assign applications accepted during the first day of the solicitation with random positions in the queue. Within minutes, applications were received far in excess of this programmatic cap. The PSB received over 200 applications, totaling more than 190 MW, during the program's first week. The applications were primarily from solar PV projects. In response, the PSB determined that no single technology should comprise more than 25 percent of the initial project queue, and required that such technology caps be reviewed regularly thereafter. This 25 percent technology cap remained in place until 2011, when the PSB elected to take projects off the waiting list by simply alternating between solar and wind projects until the program's initial 50 MW was fully subscribed (SPEED Program Rule, 2015).

The SPEED Program was established in 2005 under 30 V.S.A. § 8005 and § 8001 to promote long-term contracting with renewable generators and the development of in-state resources. It set renewable energy development goals which, if not met, would trigger adoption of an RPS. The first 50 MW of the Standard Offer Program was added as part of the Vermont Energy Act of 2009 (Act 45). The Vermont Energy Act of 2012 (Act 170) expanded the Standard Offer to 127.5 MW and mandated the use of a market-based mechanism to establish contract prices, which had previously been administratively determined. Unlike the rest of the region, Vermont's utilities continue to operate as vertically-integrated monopolies without providing retail choice. As such, the production and cost of Standard Offer contracts are allocated to Vermont's four largest utilities[28] as well as the Vermont Public Power Supply Authority on behalf of the state's 14 municipal utilities (Vermont PSB Implementation of Standard Offer Program for SPEED (Dockets 7523 and 7533), 2015).

Overall, Vermont has created a strong policy environment for small renewable energy generators. It is difficult, however, to secure permits and public acceptance for larger projects. There is a robust net metering policy, including aggregate net metering, which is applicable to projects less than or equal to 500 kW[29] and is available in all utility territories up to 15 percent of peak demand.[30] Net excess generation not used within twelve months is granted to the utility. The net metering customer retains all RECs (but is given the option to grant them to the utility). Act 99 of 2014 made several changes to the net metering rules intended to promote small-scale solar generation. First, the Act allows a utility to, at its own discretion, continue to accept solar net metering systems of 15 kW or less

[28] Green Mountain Power, Burlington Electric Department, Vermont Electric Cooperative, and Washington Electric Cooperative.

[29] Up to 2.2 MW for military installations.

[30] Or the utility's 1996 peak demand, whichever is greater. This net metering cap was recently increased from 4% of peak demand.

without the PSB's approval upon reaching the 15 percent cap. For other net metering systems, the utility can file a petition to raise the utility-specific cap with the PSB. Further, pursuant to Act 99, solar net metering systems of 15 kW or less will continue to receive a net metering rate of 20¢/kWh, while other net metering systems will receive a reduced rate of 19¢/kWh for no less than 10 years. When combined with sales of RECs and reduction in technology costs, this revenue now appears sufficient to stimulate considerable behind-the-meter development activity.

Over the last several years, the state and local utilities have also offered a series of renewable energy tax credits, renewable energy adders, and numerous grant and loan programs, many of which flow through the Clean Energy Development Fund,[31] to support the state's SPEED goal of 20 percent statewide renewable electricity sales by 2017.[32] The CEDF was established in 2005 through Act 74 (30 V.S.A. § 8015) with a goal of increasing "the development and deployment of cost-effective and environmentally sustainable electric power sources (Clean Energy Development Fund Home, 2015). The CEDF was historically funded through contributions from Vermont Yankee and is currently funded through periodic allocations from the Vermont Legislature. Due to budget limitations, the 30 percent solar business tax credit expired in 2012, although the 7.2 percent personal investment tax credit remains. CEDF grant and loan programs are offered periodically through competitive solicitations.

Vermont has yet to establish a Renewable Portfolio Standard, although such a policy was recently proposed in the 2015 legislative session. Presumably, all Standard Offer contracts will be eligible to help fulfill some aspect of a future Vermont RPS.

The Standard Offer Program has generated a large amount of development activity across the state relative to the scale of state load – particularly for solar. Successful projects range in size from residential installations to the 2.2 MW program cap. While a significant amount of new capacity (approximately 45 MW) has been successfully installed, the program has also been characterized by substantial project attrition, described in detail below, as new market entrants grapple with the challenges of putting together successful renewable energy projects. This frequent project failure has been managed through the use of technology-specific waiting lists, from which projects are called upon when program capacity becomes available. The migration from administratively-determined prices to a market-based, RFP-driven structure appears to be reducing attrition by requiring developers to post security and have a better handle on all aspects of project feasibility prior to bidding (VT H.702, 2014, 2015).

2.7.2 Policy Description

The SPEED Standard Offer Program provides long-term contracts to qualifying renewable energy projects as follows:

- Landfill gas (15 years)
- Biomass, farm methane, hydroelectric, and wind (20 years)
- Solar (25 years)

During the early program years, pricing was administratively-determined, similar to a feed-in-tariff, on an annual basis through a regulatory docket process. Contracts were awarded on a first-come, first-served basis. This annual price-setting process created a substantial time and cost burden on regulators and stakeholders. Since 2013 (as a result of the Vermont Energy Act of 2012), all pricing has been determined by competitive bidding – with price caps set at avoided cost on a technology-specific basis, with the exception of farm methane projects. This change was made to conform the program to clarifications issued by the Federal Energy Regulatory Commission ("FERC") in 2010 decisions which prohibited standard-offer rates established under state law from exceeding the PURPA avoided cost, but authorized states to employ a "multi-tiered" technology-specific avoided-cost structure in a standard offer program

[31] Which is housed within the Department of Public Service.

[32] Vermont also has a total renewable energy target schedule, which requires 55 percent of each retail electricity provider's annual electric sales to be met by renewable energy during the year beginning January 1, 2017, increasing by an additional 4 percent each third January thereafter, until reaching 75 percent on January 1, 2032. (Clean Energy Development Fund Home, 2015)

that takes into account state-law requirements to purchase electricity from particular sources of energy.[33] The solar avoided cost price cap is levelized, while all other technologies allow annual escalation of no more than 1.6 percent on no more than 30 percent of project cost.[34] Both the avoided cost price caps and the RFP process are established by the PSB. There is one competitive solicitation per year. Awards are made based on price, assuming all other eligibility criteria are met. Once a contract is awarded, projects have 24 months (solar and wind) or 36 months (all other technologies) to achieve commercial operation. All production is compensated at the successful bid price.

The programmatic goal of 127.5 MW has annual allocation targets, which are further divided by technology. Initially, the MW allocation for each technology was set at no more than 25 percent of the initial project queue. In June 2011, the PSB revised the technology guideline requiring the SPEED facilitator to admit projects on an alternative basis from the solar PV and wind waiting lists until the program was fully subscribed. The state is currently developing a new technology allocation methodology. The first 50 MW was made available in 2009 and – after significant project attrition[35] – was fully subscribed by early 2013 using the waiting list method described above to refill the program whenever project failure occurred. Incremental program MWs are offered through annual RFPs as follows: 5 MW per year for 2013-2015, 7.5 MW per year for 2016-2018 and 10 MW for 2019 through 2022. Each year, a portion of incremental capacity is reserved for ownership by Vermont utilities. This capacity is referred to as the Provider Block. The Provider Block is set at 0.5 MW for 2013-2015, 1.125 MW for 2016-2018 and 2.0 MW for 2019-2020. Projects which are determined to provide sufficient benefit to the distribution system are not counted toward the programmatic MW cap.

Competitive bids are capped at an administratively-determined avoided cost, by technology, which is updated annually by the PSB. The PSB process is public and largely driven by stakeholder inputs. Stakeholders are invited to provide cost, performance and other market data and propose financing models consistent with FERC's rules to determine the avoided cost (based on an efficiently sized and located facility) for each technology. The PSB will conduct a series of stakeholder discussions spanning multiple months to identify the appropriate avoided cost calculation methodology and prices. Such a process may be considered burdensome and costly, considering that new capacity development resulting from each of the program's annual solicitations is only 5 to 10 MW. Further, battles among stakeholders over appropriate models for avoided cost calculation in early rounds of the program have given way to less contentious and less involved proceedings focused on updating avoided costs in recent years.

Solar projects must bid a levelized price beneath the levelized cost cap. All other technologies may bid escalating prices, so long as such prices neither exceed the avoided cost cap nor escalate more than 30 percent of the project cost at more than 1.6 percent per year. Pricing also may not be front-loaded and decrease over the term of the contract. Under the RFP selection process, projects are ranked according to a levelized bid price. In its evaluation, the SPEED administrator uses a 9.75 percent target after tax return on equity as a discount rate to calculate and compare levelized bids.[36] Solar has a flat avoided cost schedule that maintains at the levelized cost cap for 25 years (the assumed project life).

33 Cal. Pub. Util. Comm'n Et.al 132 F.E.R.C. ¶ 61,047 (July 15, 2010); Cal. Pub. Util. Comm'n Et.al 133 F.E.R.C. ¶ 61,059 (Oct.21, 2010)

34 To reflect the impact of inflation on operating and maintenance expenses.

35 As of September 23, 2014, over 35% of project capacity were withdrawn or deleted from the queue.

36 This is intended to approximate the Vermont utilities' weighted average cost of capital.

The PSB set fixed, 25-year, Standard Offer rates for solar projects as follows:

- 2009: 30.0 ¢/kWh
- 2010: 24.0 ¢/kWh
- 2011: 24.0 ¢/kWh
- 2012: 27.1 ¢/kWh

The solar avoided cost rate, serving as the price cap for the RFP process, for both 2013 and 2014 is 25.7 ¢/kWh. The increase from 2011 to 2012 was likely, in part, due to the state ITC reaching its cap.

In order to encourage legitimate, realistic bidding and mitigate attrition, the PSB implemented a security requirement in the competitive procurement program. Projects submitting bids must include security of $10/kW of proposed AC capacity. This security is returned to projects that are selected and that achieve commercial operation. Projects that bid successfully but fail to execute the Standard Offer contract within 15 days of notification forfeit their security. The initial (non-competitive) program rounds did not include a security requirement, which may have unintentionally attracted highly speculative projects into the queue – only to increase the percentage of attrition later on. While it is too early to draw conclusions about whether the current security requirement has addressed this problem, only one (out of seven) projects selected by competitive bid has withdrawn from its Standard Offer contract to date.

In between contract execution and commercial operation, projects must demonstrate development progress. For example, a complete application for a Certificate of Public Good must be submitted to the PSB within one year[37] of executing a Standard Offer contract. As previously stated, solar projects must achieve COD within 2 years, and all other projects within 3 years. The SPEED facilitator has no authority to grant extensions.

2.7.3 Key Interactions

Within Vermont, renewable generators may elect to participate in either the Standard Offer or Net Metering Programs, but may not participate in both. Standard Offer contracts convey all energy, capacity and, with the exception of farm methane projects, renewable energy certificates (RECs) to the contracting utilities. Standard Offer projects may qualify to participate in other CEDF incentive programs, such as the loan program and the Solar & Small Wind Incentive Program. Under the current design, Standard Offer projects are counted toward the SPEED goal of generating 20 percent of 2017 statewide retail electric sales from new renewable resources. Outside of Vermont, the policy interactions are more complicated and not fully resolved. Since Vermont has no binding RPS, RECs produced under the SPEED Standard Offer program are frequently sold to RPS-obligated entities for compliance in other New England RPR markets. Recently, this practice became the subject of CT Docket 15-01-03, initiated to clarify the treatment of RECs associated with the Vermont SPEED resources under the Connecticut RPS and other potential double-counting situations.

2.7.4 Impacts and Observations

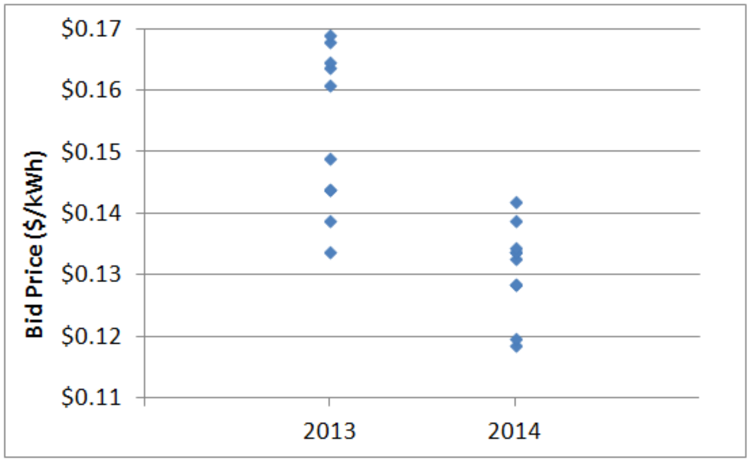
Since its launch in 2009, 23 solar PV systems totally approximately 33.9 MW have been commissioned under the Vermont SPEED program. 13 projects (23.4 MW) are currently under review by the PSB, under development or have been issued all necessary permits, but are not yet constructed.

Overall, the program has stimulated some competition in the market. In 2013, 34 proposals representing 60.4 MW were received in response to the 5 MW solicitation. In the most recent round, 18 proposals, totaling approximately 32.75 MW competed for 5 MW of available capacity. All except one of the bids were for solar PV projects. The program has demonstrated that long-term, fixed price,

[37] Except for hydroelectric projects requiring a license from FERC.

and creditworthy contracts can enable financing and drive down costs. The ten lowest cost bids (all solar) received under the 2014 RFP ranged in price from 11.87 to 14.20 ¢/kWh for 25-year fixed price contracts. This is compared to a bid price range of 13.40 to 16.90 ¢/kWh received under the 2013 RFP. The price cap in both years was 25.7 ¢/kWh.

Figure 12. Ten Lowest Cost Projects (All Solar) Selected Through 2013 and 2014 RFPs



This range of bidding, within a group of only the ten lowest-priced projects, demonstrates that the least-cost bid is neither likely to be replicable nor appropriately extrapolated to the larger volumes of projects that would be expected if such an approach were executed Massachusetts. Rather, these bids appear to represent the market's low-hanging fruit, at a diversity of project costs – the lowest of which may or may not ultimately be developable.

The initial phase of the Standard Offer program demonstrated great success in facilitating market diversity and promoting local job growth. The program supported deployment of a healthy mix of small and large scale projects, pursued mostly by local developers. As the program evolved to a competitive procurement model, smaller systems were no longer able to compete on price with larger installations, especially against national players, who are more sophisticated and can participate at lower costs. Of the seven projects selected in the 2013 and 2014 RFPs, six projects were larger than 2 MW and only two projects are by Vermont-based developers. This trend, combined with infrequent solicitations (i.e. once per year) for relatively small quantities of contracts (between 5 and 10 MW per year, which may translate into only two to five projects per year), is not conducive to driving permanent in-state jobs. The following table demonstrates the difference in project diversity between the original standard offer program and the competitive procurement program to date.

Table 26. Solar PV Project Sizes, Standard Offer Program versus Competitive Procurement Program

	Standard Offer		Competitive Procurement	
Project Size (kW)	Number of Projects	Capacity (kW)	Number of Projects	Capacity (kW)
≤15	5	48	-	-
>15 -100	12	705	-	-
>100 – 250	11	1,753	1	130
>250 – 500	7	2,549	-	-
>500 – 1000	6	5,300	-	-
>1000 – 2000	14	24,954	2	4,000
>2000	13	28,472	4	8,660
Total	68	63,781	7	12,790

Further, the program has also proven that ample challenges exist between submitting an application and executing a contract. Numerous projects have been removed from the list of approved and contracted projects. As of September 2013, 35 percent (22.3 out of 63.8 MW) of the projects initially selected through the Standard Offer program had withdrawn from the queue. Many of these were small or medium-sized systems. A higher percentage of projects have failed than the percentage of MW that have reached service. As shown in Table 27, 56 percent of the projects initially selected through the Standard Offer program have so far failed, while only 22 percent have reached in-service and an equal percentage are still pending. Thus if a similar percentage of pending projects withdraw as have withdrawn to date, the failure percentage could end at approximately 67 percent of total projects.

Table 27. SPEED Standard Offer Project Success Rate (As of September 23, 2014)[38]

Project Size (kW)	Number of Selected Projects	In-Service	Withdrawn	Active
≤15	5	0	5	0
>15 -100	12	6	6	0
>100 – 250	11	1	9	1
>250 – 500	7	0	7	0
>500 – 1000	6	0	3	3
>1000 – 2000	14	4	3	7
>2000	13	4	5	4
Total	68	15	38	15
Percentage	100%	22%	56%	22%

Since the program became competitive, only one project has dropped out so far. This change may be attributable to a combination of reasons. One primary factor is the new $10/kWh proposal security requirement designed to mitigate speculative bidding. Another factor that may lead to higher project success rate is the program's switch to a competitive procurement model, which favors more sophisticated players. However, given that none of the selected projects are currently operational, the project success rate may change in the future. Further, as the procurement volume increases in later years, the effectiveness of the proposal security and the competitive program in impeding attrition may become more apparent.

[38] This table does not include projects from the 2013 and 2014 SPEED competitive RFP.

2.8 Value of Solar Tariffs

2.8.1 Introduction

In the heat of a nation-wide debate regarding cross-subsidization of net metering, the need for a more accurate and transparent method for capturing the value of services provided in each direction (customer to utility and utility to customer) is becoming apparent. Value of Solar Tariffs (VOST) are a rate design approach aimed at exposing the cost and benefits of distributed solar generation, allowing more informed policy and investment decision making. (Fine, Saraf, Kumaraswamy, & Anich, 2014). So far, there are two examples of VOST implementation – in the state of Minnesota and the City of Austin, Texas - both of which operate under a vertically-integrated monopoly market structure.

In 2012, Austin Energy, a publicly-owned utility, became the first U.S. utility to replace net metering with a VOST for residential customers only. The tariff was designed to compensate customers for the value of solar generation they produced in support of the utility's 2020 local solar generation goal of 100 MW (Austin Energy, 2013). The Minnesota legislature enacted Chapter 85 in 2013 with the intent to provide maximum encouragement to distributed generation while protecting ratepayers and the public. The bill directs the state Department of Commerce, in conjunction with the Public Utilities Commission, to establish a methodology for determining the value of solar and authorize the states' public utilities to provide VOST as an alternative option to net metering. (Minn. Statute § 216B.164, Subd. 10, n.d.)

2.8.2 Policy Description

VOST is a rate design approach modeled after, and adapted from, a net metering tariff in structure, but with elements of a standard-offer or feed-in tariff approach. Solar customers enter into long-term value of solar tariffs with distribution utilities to receive compensation for onsite generation. Under both VOSTs and net metering, customers purchase electricity from utilities at retail rates. Unlike traditional net metering, VOSTs do not compensate a solar customer's generation at the retail rate. Instead, the generation is compensated based on a calculated value of solar rate in dollars per kilowatt hour.[39] In this regard, VOSTs are sometimes called a bi-directional rate design as it calculates the value of electricity provided from solar customers to utilities and from utilities to solar customers separately. (Bird, et al., 2013)

The VOST rate is derived from an analysis designed to determine the net benefit associated with distributed solar generation. VOST rates developed to date have been utility-specific. In Austin, the rate was determined by Austin Energy, a city-owned utility. In Minnesota, the state regulator was responsible for creating a methodology for determining the value of solar. Utilities can then apply the methodology to establish a VOST, subject to state approval, as an alternative to net metering. (Minnesota Department of Commerce, n.d.). Typical components to be considered in a VOST calculation include:

- Avoided energy costs
- Transmission and distribution service costs
- Ancillary service costs
- Avoided environmental costs
- Societal benefits (e.g. economic growth and health benefits)

VOSTs should be updated on a regular basis to reflect changes in energy costs and other market conditions. Both Austin and Minnesota's VOSTs are subject to annual review. In Minnesota, utilities are required to recalculate the tariff for new systems on an

[39] In Minnesota, net excess generation is credited to the customer's next monthly bill for up to twelve months. After twelve months, any unused credits will be eliminated. Austin Energy allows net excess generation to be rolled over to the next year.

annual basis and file the revised tariff for state approval.[40] Table 289 shows Austin Energy's VOST rates for 2013 and 2014. The rate change was mainly driven by decline in natural gas prices, along with changes in loss savings, transmission savings and assumed project life.

Table 29. Austin Energy Value of Solar Rates

($/kWh)	2013	2014
Value of Solar Rate	$0.128	$0.107

As an alternative to net metering, VOSTs are nominally targeted to residential and small C&I customers that are traditionally eligible for net metering. The Minnesota VOST, for example, has a 1-MW system cap. Austin Energy initially had a system size limit of 20 kW. However, the size cap was eliminated in August 2014, and all residential solar systems are now eligible for the VOST. (Resolution No. 20140828-157, 2014). There are no aggregated program caps in either program.

2.8.3 Key Interactions

As an alternative to traditional net metering, VOST can be implemented with a suite of solar policies that are proven compatible with net metering. On a broader scale, VOST can replace net metering as an additional support for small and medium scale solar projects, while large PV systems continue to rely on RPS, competitive procurements and some tax incentives. All VOST projects can participate in state RPS and solar carveouts.[41] In Austin and Minnesota, there are no provisions that prevent VOST projects from receiving rebates and other direct upfront payments. The interaction between VOST and other performance-based-incentives, such as feed-in tariffs and competitive long-term contracts, is more ambiguous. Depending on whether policymakers view VOST as utility bill offsets or an actual incentive policy, it may affect whether VOST and traditional PBIs are treated as complimentary or mutually exclusive policy options. (Bird, et al., 2013)

Regarding tax incentives, some have expressed concern regarding whether VOST is considered a buy-all, sell-all approach, which could potentially affect system owners' ability to obtain some tax credits that have onsite generation thresholds. Some have argued that VOSTs are a buy-all, sell-all approach as it involves customers paying for all electricity consumption at one rate and being compensated for all generation at a different rate. Other commentators have argued that, like net metering, VOST is an offsetting credit for customer generation, and hence, is not a buy-all, sell-all design. The federal Internal Revenue Service is currently conducting a formal review on the tax implications of VOST. [42]

2.8.4 Impacts and Observations

VOST can be implemented as a replacement or an alternative to net metering. In Minnesota, utilities are provided with the options to switch to a VOST approach. Since the VOST methodology was established in April 2014, no utilities have yet proposed a VOST with the state. In Austin, where residential VOST is mandated, there is insufficient data to date to draw statistical conclusion on the effectiveness of VOST in Austin. As a result, there is very little industry experience to go on, particularly in locations with modest

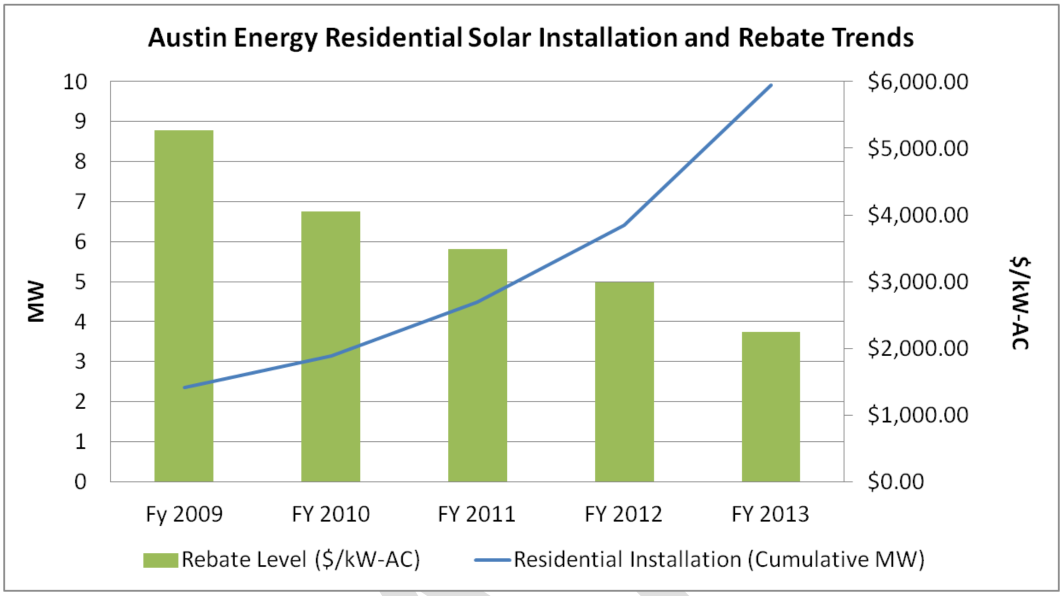
[40] In Minnesota, the VOST for existing systems is locked-in for the life of the solar PV system. (Fine, Saraf, Kumaraswamy, & Anich, 2014)

[41] In Minnesota, RECs generated from VOST facilities are owned by public utilities. (Minn. Statute § 216B.164, Subd. 10, n.d.) This requirement is established based on Minnesota's non-competitive market structure and will not apply to VOST in a competitive market, such as Massachusetts.

[42] In August 2013, Skadden, Arps, Slate, Meagher & Flom LLP (the firm) filed a legal memo with the Alliance for Solar Choice regarding the tax implications of feed-in-tariffs and value of solar tariffs. The firm noted that Section 25 D Credits requires 80 percent of the generation to be used onsite. The firm argued that FITs and VOSTs framework require the sales of all customer generation, and hence, could jeopardize a resident's eligibility to receive Section 25 D Credits. (The Solar Alliance for Solar Choice, 2013). At that time, Austin Energy asserted that VOST is an offsetting credit for customer generation, and a sale of all output from customer generators to Austin Energy is not involved. (Bird, et al., 2013). In September 2014, an Austin homeowner filed an Information Letter Request with the federal Internal Revenue Service to address the tax impacts of Austin Energy's VOST. The IRS will formally review the tax implications of Austin Energy's VOST. At time this section is written, the IRS has yet not issued a decision (The Solar Alliance for Solar Choice, 2014).

insolation and competitive markets. However, it is observed that there has been accelerated growth in the market sector, while rebate levels continue to decline since VOST implementation. There have been talks to extend VOST to the commercial sector. (Rabago, 2014)

Figure 13 . Austin Energy Residential Solar Installation and Rebate Trends



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