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List of Acronyms

ACP	alternative compliance payment
BOS	balance of systems
bps	basis points
C&I	commercial and industrial
IRR	internal rate of return
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
MA DOER	Massachusetts Department of Energy Resources
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt-hour
NPV	net present value
NREL	National Renewable Energy Laboratory
PPA	power purchase agreement
RPS	renewable portfolio standard
SACP	solar alternative compliance payment
SAM	System Advisor Model
SCCA	Solar Credit Clearinghouse Auction (Massachusetts)
SREC	solar renewable energy certificates
TMY	typical meteorological year
W	watt
WACC	weighted average cost of capital

Executive Summary

Solar carve-outs, which require a percentage of a state's renewable portfolio standard (RPS) to be met with solar resources, have price caps in eight states.[1] These price caps—called solar alternative compliance payments (SACPs)—allow for RPS compliance without supporting solar deployment through the procurement of solar renewable energy certificates (SRECs). SRECs represent the environmental attributes of one megawatt-hour of solar generation. If solar projects cannot be developed with an SREC price that is lower than the SACP, new solar deployment may be postponed.

We examine the potential impact of the scheduled reversion of the Section 48 investment tax credit (ITC) in 2017 from 30% to 10% of project costs for corporate entities on solar carve-out compliance. We analyze the potential for SREC prices to approach or exceed alternative compliance payment rates for commercial solar projects. Our analysis is limited to states that have a solar carve-out, an SACP, and an active SREC market: Delaware, District of Columbia, Maryland, Massachusetts, New Hampshire, New Jersey, Ohio, and Pennsylvania. While our analysis is limited to these states, the ITC reversion will likely have an impact on solar deployment across the country. We are focused on whether carve-out compliance will be met through solar deployment, not on many other key aspects of the ITC reversion, such as implications for the solar industry (e.g. SEIA 2015).

Whether SACPs will be used to meet solar carve-outs is a function of how high solar carve-outs are set and future SREC prices. Based on our projections, the Massachusetts and Maryland RPSs have the greatest need for additional solar capacity to meet their carve-outs, though the smaller markets of New Hampshire, Delaware, and Washington, D.C. require large expansions to meet their carve-outs relative to their market sizes.

To examine future solar competitiveness in solar carve-out states after the ITC reversion, we model 2017 PPA rates under high and low installed cost scenarios using NREL's System Advisor Model (SAM). We focus our analysis on commercial PV specifically, comparing PPA rate estimates in SAM to forecasted commercial electricity rates.

In the low cost scenario, we assume 35% reductions in BOS costs, $0.20/W reduction in installer margin, and a 100 basis point (bps) reduction in the cost of capital. In the high cost scenario, we assume a 15% reduction in BOS costs, $0.10/W reduction in installer margin, and a 50 bps reduction in the cost of capital. We assume SREC prices in years 1-3 at 90% of the September 2015 spot price, and in years 4-10 at 80% of the SACP. Given their volatility and uncertain availability, we do not include state incentives in our analysis.

Assuming a 10% ITC, under these cost reduction scenarios, Washington, D.C., Massachusetts, and New Jersey are projected to have SREC prices lower than SACP rates, while SREC prices in Maryland are at the SACP in the high cost scenario. SREC prices in Ohio and Pennsylvania are estimated to be considerably above the SACP, indicating that carve-outs in those states would be

[1] Additional states have cost containment mechanisms on the entire RPS through a rate impact or revenue requirement cap, for example. See Heeter et al. 2014a for more information.

met with out-of-state resources, or compliance entities would use SACPs. These results are summarized in Table ES-1.

Table ES-1. Summary of Sensitivity of State Solar Carve Outs to ITC Reversion

State	Sensitivity to capacity reductions	Sensitivity of project economics	Overall sensitivity to ITC reversion
Delaware	High	High	High
District of Columbia	High	Low	Medium
Maryland	Medium	Medium	Medium
Massachusetts	Low	Low	Low
New Hampshire	Low	Medium	Low
New Jersey	Low	Medium	Low
Ohio	High	High	High
Pennsylvania	Medium	High	Medium

In all the states examined, state policies currently have a considerable impact on reducing solar project costs under both high and low cost scenarios. To date, most state policymakers have not focused explicitly on implementing policies to address the ITC reversion. Examples of such polices include: extension of state tax credits or rebates, or expansion of net metering program caps.

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Figure and Tables

1 Introduction

Businesses that invest in a commercial solar project are eligible for a solar investment tax credit (ITC) equal to 30% of the qualifying costs of the project. Residential investors are eligible for a 10% ITC. The ITC is scheduled to revert to 10% for businesses and expire for residential investors after December 31, 2016. The ITC in its current form offsets a portion of solar project capital costs, improving the financial viability of solar projects. The ITC reversion will effectively increase the capital costs borne by project developers and reduce the financial viability of certain projects. The higher capital cost burden of solar projects could force developers to increase the cost of solar generation by 10%–70% in some markets (Comello and Reichelstein 2015; Mueller and Ronen 2015). The increased costs of solar generation after an ITC reversion could reduce annual installed capacity by more than 50% (EIA 2015; GTM 2015).

This study assesses an ITC reversion's potential impact on the ability of states to meet solar energy targets, commonly called solar "carve-outs." Solar carve-outs require designated load-serving entities (regulated entities) to provide a given amount of power from solar energy for renewable portfolio standard (RPS) compliance. Fourteen states and Washington, D.C. administer solar carve-out programs (Figure 1). Another six states carve out a percentage of their RPS for distributed generation (DG), which includes eligible solar resources.

Regulated entities comply with carve-outs through the retirement of solar renewable energy certificates (SRECs). An SREC represents the renewable energy component of one megawatt-hour (MWh) of electricity generated by solar power. Regulated entities can either generate solar energy and retire the associated SRECs or purchase and retire the SRECs from another generation source. For the purposes of this report, a "compliance SREC" refers to an SREC used for carve-out compliance. SRECs may be used for other purposes (e.g., voluntary green power).

Seven states and Washington, D.C. allow regulated entities to make solar alternative compliance payments (SACPs or simply "compliance payments") for carve-out compliance in lieu of SRECs (see Figure 1). For the purposes of this study, we refer to the eight states, including Washington, D.C., that allow compliance payments as "solar ACP states." The solar ACP states designed compliance payments as cost-capping mechanisms with rates exceeding prevailing SREC prices. Regulated entities only have a financial incentive to make compliance payments rather than purchase SRECs for carve-out compliance only when SREC prices approach the compliance payment rate. In most cases, the compliance payment rate sets a ceiling on SREC prices (Bird et al. 2011).[2] It follows that solar deployment in the solar ACP states will generally be limited to projects that have a break-even SREC price below the compliance payment rate.

[2] In some cases, utilities may be willing to pay SREC prices above SACP rates if SREC payments are recoverable through ratemaking.

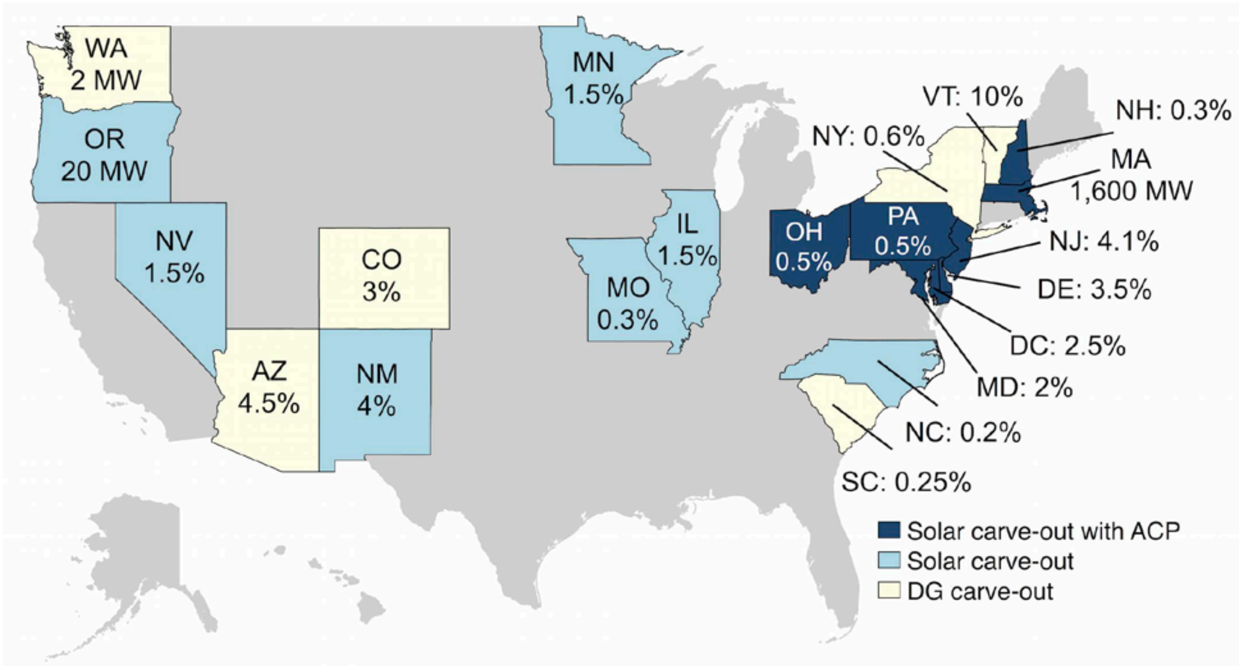


Figure 1. Solar carve-out programs and ACP policies

Numbers reflect percentage or capacity (MW) carve-out targets.

Our analysis focuses on the eight solar ACP states because of the sensitivity of carve-out compliance to the ITC reversion in these states. All else being equal, a smaller commercial ITC will increase the capital costs borne by solar project developers and increase solar project revenue requirements. Increased revenue requirements could manifest in higher SREC prices or lower developer margins. In carve-out states without compliance payment policies, compliance SREC demand is effectively fixed at the carve-out rate and therefore not responsive to SREC prices. As a result, the ITC reversion may have a limited impact on carve-out compliance in states without compliance payment policies. In contrast, compliance payments allow regulated entities to respond to changes in SREC prices, therefore compliance SREC demand in the solar ACP states is dynamic rather than fixed. The ITC reversion could reduce carve-out compliance in the solar ACP states if SREC prices approach compliance payment rates, at which point regulated entities would make compliance payments in lieu of SREC purchases.

The future outlook of carve-out compliance in the solar ACP states is a function of two related factors. The first factor is the difference between the solar capacity available for compliance purposes (SREC supply) and the capacity required for compliance purposes (SREC demand). The second factor is the potential impact of the ITC reversion on SREC prices and solar project economics. The first factor will determine which state carve-out programs are sensitive to the ITC reversion. The second factor will determine more precisely in what states the ITC reversion could cause carve-out compliance issues. This study explores both factors to answer two questions:

- Are the solar ACP states likely to meet their solar carve-out targets?
- What is the potential for compliance payment use in these states after ITC reversion?

Section 2 provides background on the concepts of solar carve-outs and SREC markets. Sections 3 and 4 assess the sensitivity of carve-out compliance to the ITC reversion in the solar ACP states based on projections of future installed capacity and carve-out capacity requirements. Section 5 details the results of an economic modeling analysis conducted using NREL's System Advisor Model (SAM) to investigate the ITC reversion's potential impact on SREC prices in certain states and thus the potential use of compliance payments by regulated entities. Section 6 identifies the conclusions and implications of this analysis.

2 Background

This section summarizes the carve-out programs in the eight solar ACP states and the status of SREC markets.

2.1 Current Status of Solar Carve-out Programs

State solar carve-outs in the solar ACP states required regulated entities to retire about 2,581,000 MWh of SRECs in 2014 (BNEF 2015). Table 1 summarizes, by state, long-term carve-out targets, SRECs required for compliance in 2014, compliance rates as of 2013, and installed capacity as of 2014.

"Compliance rate" refers to the percentage of solar carve-out targets that are met through compliance SRECs. Compliance rates do not necessarily reflect whether the state has sufficient installed capacity to meet annual carve-out targets. Regulated entities in states with insufficient capacity may nonetheless achieve compliance through the retirement of SRECs from other states, where allowed. Alternatively, non-compliance can occur even if sufficient capacity is available if other sources of demand exist for SRECs (e.g., voluntary markets).

Table 1. Summary of State Solar Carve-outs (2014)

State	Solar carve-out	SRECs required (x1,000)[a]	Carve-out compliance rate (%)[b]	Installed capacity (MW)[c]
Delaware	3.5% by 2025	66	100	61
District of Columbia	2.5% by 2023	65	96	13
Maryland	2% by 2020	206	100	242
Massachusetts	1,600 MW by 2020[3]	506	97	806
New Hampshire	0.3% by 2014	32	76	8
New Jersey	4.1% by 2028	1,430	100	1,489
Ohio	0.5% by 2026	149	100	104
Pennsylvania	0.5% by 2021	128	100	247

[a] BNEF 2015; [b] Barbose 2014; [c] SEIA 2015b

Compliance issues in New Hampshire and Washington, D.C. resulted from insufficient installed capacity or capacity "shortfalls." In 2014, New Hampshire had enough installed capacity to meet about 31% of the state's solar carve-out target, while Washington, D.C. had enough capacity for about 24% of its target. The states' compliance rates suggest that regulated entities used out-of-

[3] In April 2014, the Massachusetts Department of Energy Resources (MA DOER) increased the state's carve-out from 400 MW to 1,600 MW of new capacity (installed after January 1, 2013). The MA DOER sets annual targets through a formula designed to constantly balance supply and demand. When the supply of SRECs exceeds demand in a given year, excess SRECs are placed into the Massachusetts Solar Credit Clearinghouse Auction (SCCA). The quantity of SRECs in the SCCA in one year is added to the compliance requirement of subsequent years, so that over-supply in one year is automatically absorbed by demand in the following years. Massachusetts held its first SCCA in 2013 after temporary under-supply of SRECs following the program's implementation in 2010.

state SRECs to achieve partial compliance.[4] Every other state except Massachusetts had sufficient capacity installed in 2014 for regulated entities to comply with carve-out targets.

2.2 SREC Markets

Demand for compliance SRECs has resulted in competitive markets for the trade of SRECs in the eight solar ACP states. As in any competitive market, SREC prices are a function of supply (SRECs generated by solar system owners) and demand (SRECs required for carve-out compliance). High compliance rates in the solar ACP states indicate that SRECs are the primary mechanism for solar carve-out compliance. High SREC use suggests that sufficient SREC supplies are available to keep prices below compliance payment rates. In September 2014, SREC prices ranged from about 12% of compliance payment rates in Ohio to about 96% of compliance payment rates in Washington, D.C. (SRECTrade).[5]

The relationship between SRECs, compliance payments, and solar project viability can result in the following cycle of solar deployment (Figure 2): 1) Carve-out adjustments (e.g., annual increases) create capacity shortfalls and increase demand for SRECs. SREC demand exerts upward pressure on SREC prices. 2) Higher SREC prices open solar markets to solar projects with higher break-even SREC prices and increase solar deployment. 3) Increasing supplies of SRECs eventually saturate compliance markets and may ultimately exceed the quantity demanded for compliance by regulated entities. 4) Excess SREC supplies drive down SREC prices and again reduce solar deployment to projects with lower break-even SREC prices. 5) The cycle renews if carve-out change (e.g., annual adjustments) creates a new SREC demand.

Figure 2. Schematic of the SREC market cycle

Past periods of high SREC demand and high SREC prices have caused excess SREC supply in New Jersey, Ohio, and Pennsylvania. Following the implementation of the New Jersey solar carve-out program in 2010, surging demand drove weighted-average SREC prices over $400/MWh in 2012 and fueled installed capacity growth from 132 MW in 2010 to 419 MW in 2012. SREC supply outstripped demand and New Jersey weighted-average SREC prices fell below $200/MWh. As a result, annual installed capacity fell from 419 MW in 2012 to 236 MW in 2013 (GTM 2015). Similarly, Ohio and Pennsylvania SREC prices fell as low as $10/MWh following excess generation of SRECs.

[4] As of 2011, Washington, D.C. prohibits the use of out-of-state SRECs for carve-out compliance. However, the amendment grandfathered out-of-state facilities registered to sell SRECs into Washington, D.C. prior to 2011. The New Hampshire programs accept SRECs from generators within the New England control area.
[5] Based on highest vintage 2014 price in September 2014.

Six of the solar ACP states designed compliance payment rates to decline over time to account for assumed reductions in solar project costs over time (Figure 3). The relationship between SREC prices and compliance payment rates implies that SREC prices will decline over time in response to declining compliance payment rates in these six states. Declining SREC prices will limit financially viable projects to those with lower break-even SREC prices.

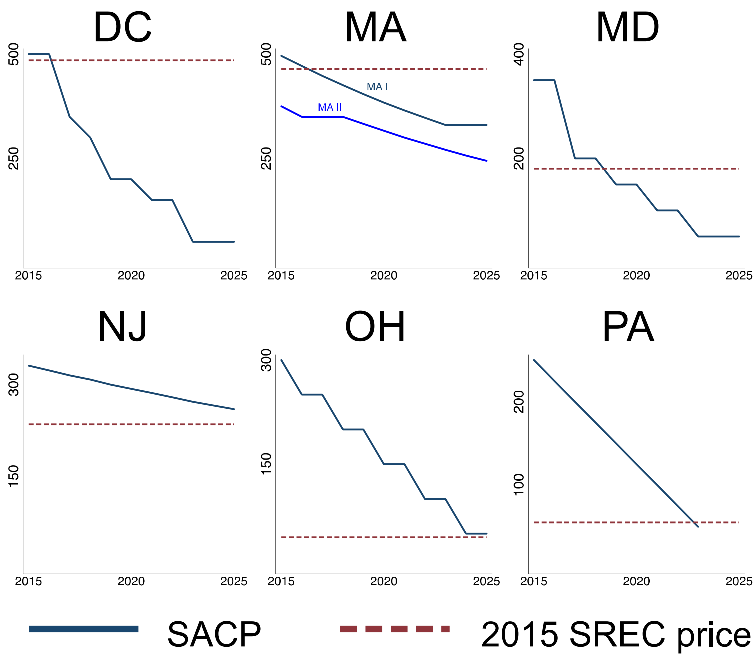


Figure 3. SACP rates ($/MWh) from 2015 to 2025 for the six solar carve-out states with declining SACP rates

Peak 2015 SREC price provided for illustrative purposes. MA I and MA II refer to SACP rates for the Massachusetts Solar Carve-out I and Solar Carve-out II programs.

3 Future Outlook of Solar Carve-out Compliance

This section and Section 4 explore which state carve-out programs are sensitive to an ITC reversion based on the difference between the solar capacity available for compliance purposes (SREC supply) and the capacity required for compliance purposes (SREC demand). We use market and government forecasts to project future installed capacity in the solar ACP states. We then estimate the additional solar capacity required to generate sufficient compliance SRECs for near- and long-term solar carve-outs. Last, we compare capacity forecasts with required capacity targets to assess how reduced SREC supplies following the ITC reversion could affect carve-out compliance.

3.1 Projected Capacity in the Solar ACP States

Annual installed capacity grew 185% from 2010 to 2014 in the eight solar ACP states (GTM 2015). Market and government forecasts project continued growth in installed capacity through 2016, but anticipate a significant reduction in annual installed capacity due to the ITC reversion in 2017 (EIA 2015; GTM 2015).[6] The ITC reversion is projected to have a particularly significant impact on utility-scale projects that rely more heavily on the ITC (84% reduction), in comparison to distributed solar projects that rely less heavily on the ITC (20% reduction) (GTM 2015). Utility-scale solar plays a less prominent role in solar markets in the solar ACP states than in western solar markets. As a result, the ITC reversion is projected to have a relatively low impact on solar deployment in the solar ACP states. GTM (2015) projects a temporary reduction in annual installed capacity in the solar ACP states of 25% in 2017, which is much lower than GTM's forecast of a 57% reduction in annual installed capacity nationwide.

Market and government forecasts differ in their projections of the sustained effect of the ITC reversion. GTM (2015) projects a temporary reduction in annual installed capacity. GTM projects annual installed capacity growth in the solar ACP states to fall to 16% in 2017, but rise in every subsequent year to 21% by 2020. In contrast, EIA (2015) projects a more sustained depression in annual installed capacity, with annual growth in residential and commercial capacity falling from 30% to 6% following the ITC reversion and remaining at about 6% annual growth through 2040 (Figure 4).[7]

[6] This report uses a "market" forecast (GTM 2015) and a "government" forecast (EIA 2015) as lower and upper bounds of the ITC reversion's impact on solar deployment. The GTM (2015) forecasts assume no ITC extension. GTM assumes that distributed solar and non-residential markets will remain resilient in a post-ITC reversion environment, but that utility-scale solar will see significant reductions in capacity growth. Prior to the ITC reversion, GTM projects strong growth in 2015 and 2016 in the residential (49% and 56%) and non-residential (40% and 45%) sectors. In solar ACP states, GTM assumes resumed growth in the non-residential sector in New Jersey in response to more stable SREC pricing.

[7] The GTM (2015) estimate is based on projections for the solar ACP states, while the EIA estimate is based on a nationwide projection.

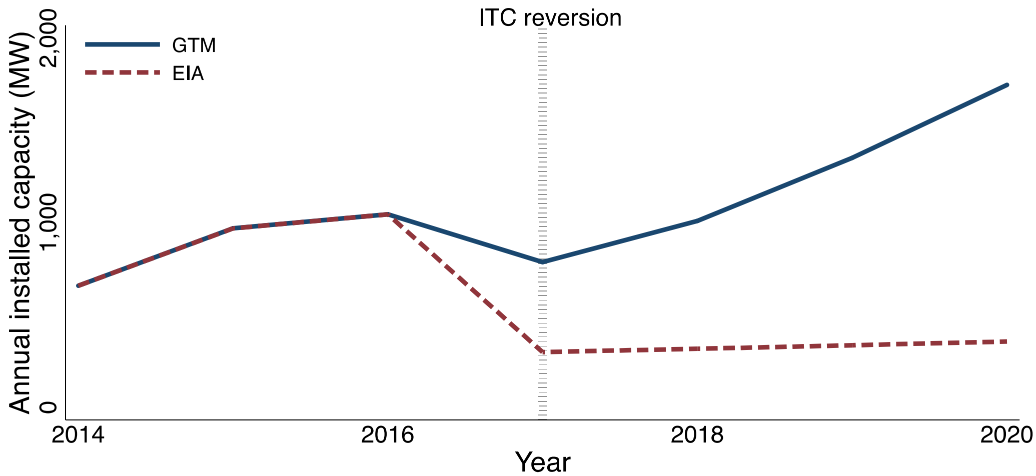


Figure 4. Projections of annual installed capacity in the solar ACP states

Source: GTM 2015. EIA projection is based on an NREL estimate with an assumed 6% annual growth rate following the ITC reversion.

GTM (2015) projects an additional 6,900 MW of capacity installed in the solar ACP states by 2020, or about 9,900 MW of cumulative installed capacity. New Jersey (42%) and Massachusetts (32%) account for the majority of projected new capacity in the solar ACP states. Using historical data and market forecasts to project installed capacity from 2015 to 2030, our analysis estimates that the solar ACP states could install as much as 17,900 MW by 2030, or a cumulative capacity of 20,900 MW (Figure 5).[8] Our projection does not account for potential technical limitations as solar PV reaches higher levels of penetration or the potential impacts of net metering caps. However, only Washington, D.C. is projected to exceed 10% of its technical potential (Lopez et al. 2014), and several studies suggest that distribution networks can accommodate high penetrations of distributed solar PV (for examples see Milligan and Kirby 2010; Coddington et al. 2012; Bank et al. 2013).

[8] GTM (2015) projections end in 2020. NREL assumed that the projected annual growth rate from 2015 to 2020 would continue linearly from 2021 to 2030, and used the growth rate from 2015 to 2020 to project values from 2021 to 2030.

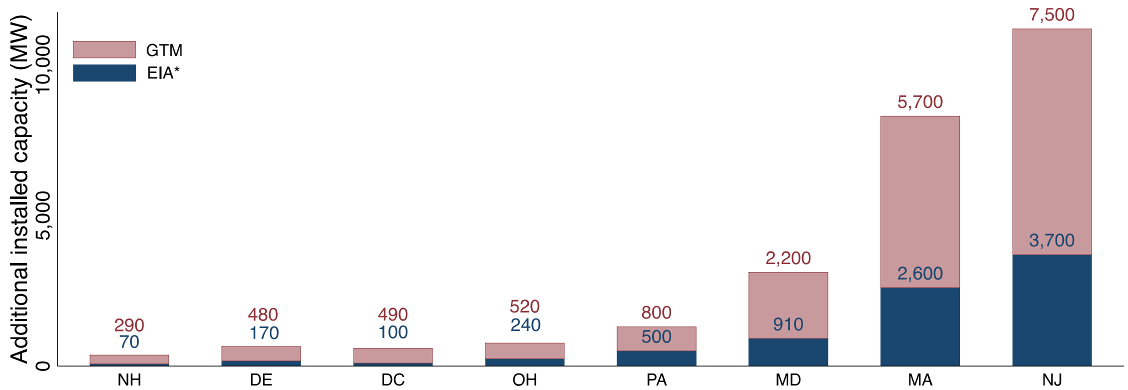


Figure 5. Market forecasts of additional installed capacity from 2015 to 2030 by solar ACP state

Numbers are NREL estimates based on GTM (2015) and EIA (2015). *Based on national annual growth rate of 6% following ITC reversion.

3.2 State-Required Additional Capacity

State solar carve-out targets will require about 3,300 MW of new solar capacity by 2030 in the solar ACP states, about a 112% increase over current installed capacity in the states.[9] Figure 6 illustrates the additional capacity required to meet peak solar carve-out targets by state.

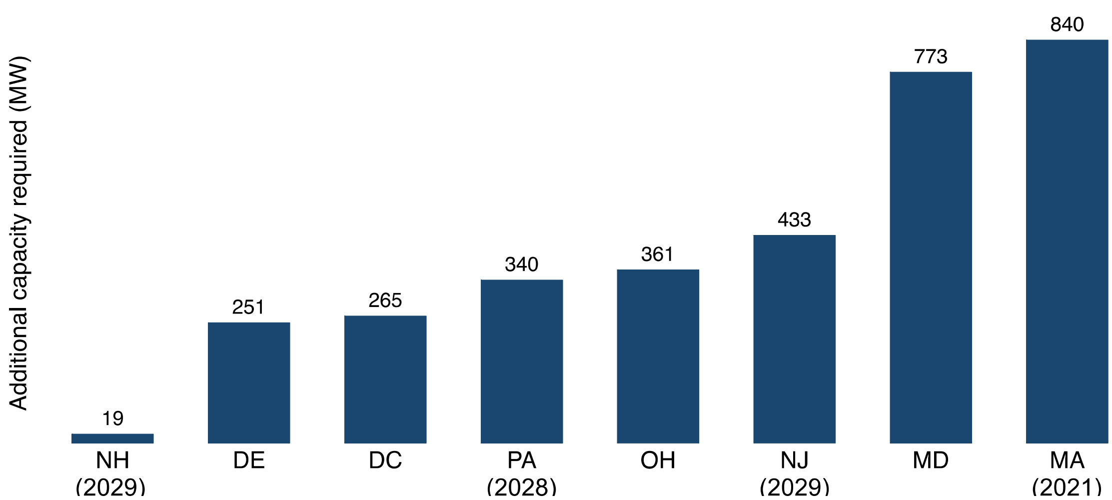


Figure 6. Additional capacity (MW) required to meet peak carve-out targets

Based on difference in cumulative installed capacity in 2014 (SEIA 2015) and forecasts of required capacity (BNEF 2015). Peak target year is 2030 unless otherwise noted in parentheses. MA based on difference between required capacity (1,600 MW), capacity operational under the Solar Carve-out I program (647 MW), and qualified capacity under the Solar Carve-out II program (113 MW).

Figure 6 provides a rough benchmark of the additional capacity required to meet long-term targets; however, the actual solar capacity necessary to ensure a sufficient SREC supply will vary for two reasons. First, not all solar power generated will produce saleable SRECs for carve-

[9] NREL calculated required capacity based on a conversion of SREC requirements in MWh (BNEF 2015) to capacity in MW through state-level solar PV capacity factors derived from NREL's SAM. We assumed a state-specific mix of utility-scale and rooftop PV systems based on data from NREL's Open PV Project.

out compliance. Solar generators must register with relevant state SREC tracking systems in order to sell SRECs (Bird et al. 2011). Total installed capacity will not necessarily reflect registered capacity, and some projects may generate solar energy without generating saleable SRECs. Further, a small but growing number of SRECs are being sold into voluntary markets (Bird et al. 2011; Heeter et al. 2014b) where they become unavailable for RPS compliance purposes. Second, four solar ACP states (Delaware, New Hampshire, Ohio, and Pennsylvania) allow the use of out-of-state SRECs for RPS compliance. States that allow out-of-state SRECs will typically require less additional in-state capacity for regulated entities to achieve carve-out compliance. Maryland, Massachusetts, and New Jersey explicitly require the use of in-state SRECs for carve-out compliance. As of 2011, Washington, D.C. prohibits the use of out-of-state SRECs except from grandfathered out-of-state facilities registered before the 2011 RPS amendment. The first factor (non-saleable SRECs) will generally increase the additional in-state capacity necessary to meet carve-out targets, while the second factor (out-of-state SREC use) will generally reduce the additional capacity required to meet targets. Therefore, our estimates of required capacity serve only as a rough benchmark to identify states that are susceptible to SREC shortages in a post-ITC environment.

4 Projected Future Carve-out Compliance

4.1 Installed Capacity Under Forecasted ITC Reversion Scenarios

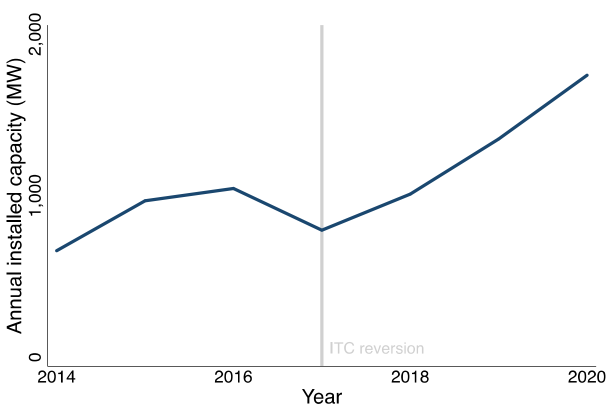
We project two plausible scenarios of future installed capacity based on market and government forecasts to assess in which solar ACP states that carve-out compliance may be sensitive to the ITC reversion (Figure 7):

Scenario #1: Temporary ITC effect

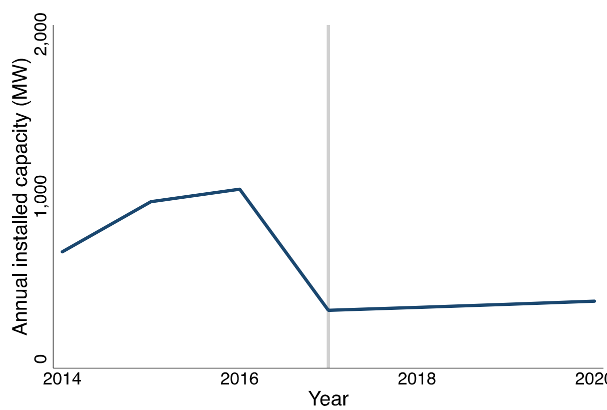
We assume the ITC reversion causes a temporary reduction in annual installed capacity in 2017 (GTM 2015). In this scenario, state solar markets rebound after the ITC reversion and exceed pre-ITC reversion annual installed capacity before 2020.

Scenario #2: Permanent ITC effect

We assume the ITC reversion permanently reduces annual installed capacity growth. In this scenario, state annual installed capacity growth falls to 6% after 2017 (EIA 2015).



Scenario 1. Temporary ITC effect



Scenario 2. Permanent ITC effect

Figure 7. Market-forecasted (Scenario 1) and government-forecasted (Scenario 2) installed capacity (MW) scenarios post-ITC reversion.

Figure 8 illustrates the two scenarios relative to future required capacity in the solar ACP states. The projections suggest that carve-out compliance may be sensitive to the ITC reversion in Delaware, Maryland, Ohio, Pennsylvania, and Washington, D.C. The analysis suggests that current installed capacity and projected future capacity make carve-out compliance in Massachusetts, New Hampshire, and New Jersey robust against the ITC reversion.

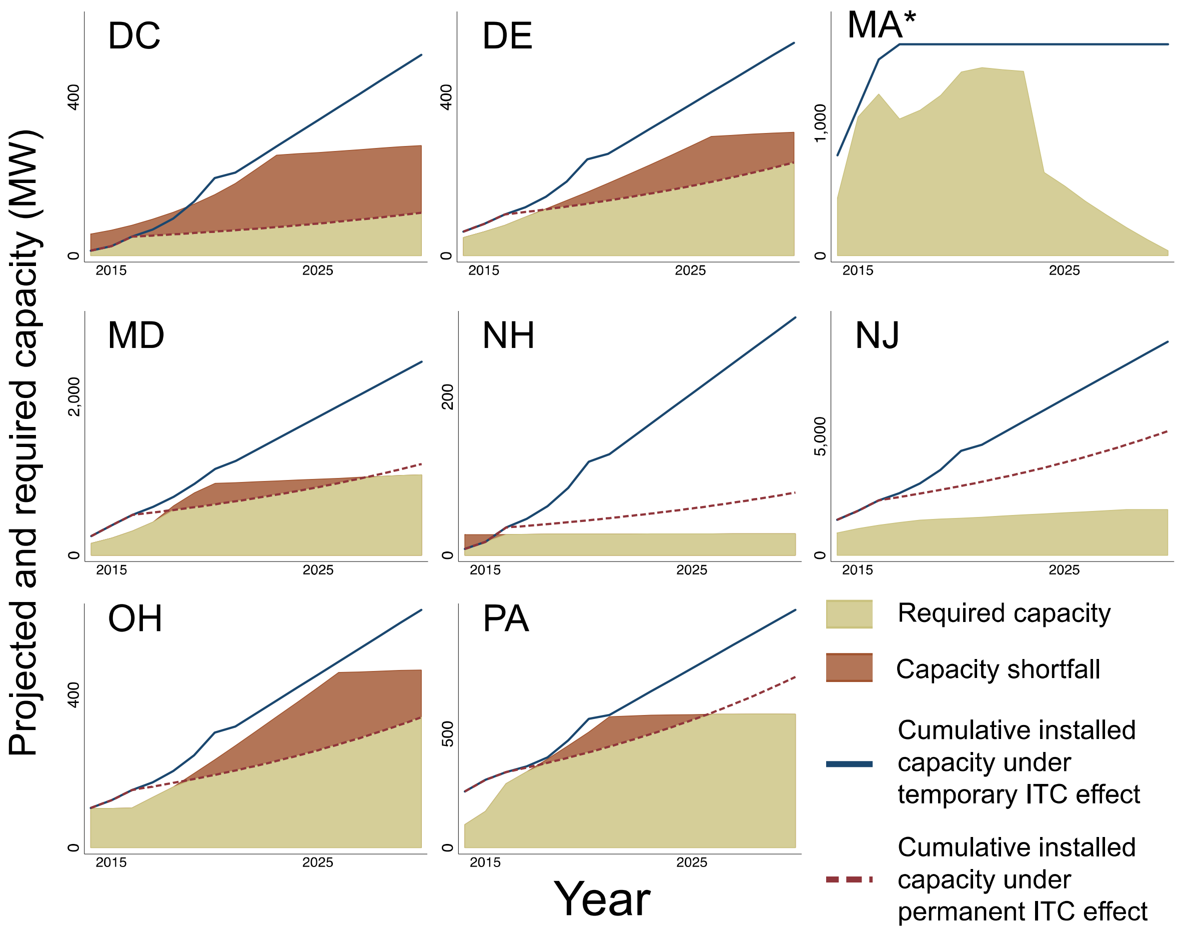


Figure 8. Projected capacity (MW) and capacity required to comply with carve-out targets through in-state SRECs, by state

Note: Capacity "shortfalls" occur where required capacity exceeds projected capacity under the permanent ITC scenario. *Projected capacity for Massachusetts represents "qualified" capacity under the Massachusetts Solar Carve-out II program. Qualified capacity is capped at 1,600 MW.

4.2 Forecasted SREC Availability

Constraints on new installed capacity following the ITC reversion in Delaware, Maryland, Ohio, Pennsylvania, and Washington, D.C. could be sufficient to cause temporary or long-term compliance SREC shortages. Figure 8 highlights capacity "shortfalls" over time where required capacity exceeds capacity projected under the permanent ITC scenario. Projected capacity shortfalls peak at about 30 MW in 2017 in the temporary ITC effect scenario and at about 630 MW in 2023 in the permanent ITC effect scenario (Figure 9). The sum of capacity shortfalls from 2017 to 2030 equate to SREC shortages of about 215,000 MWh in the temporary ITC effect scenario and about 8.4 million MWh in the permanent ITC effect scenario.

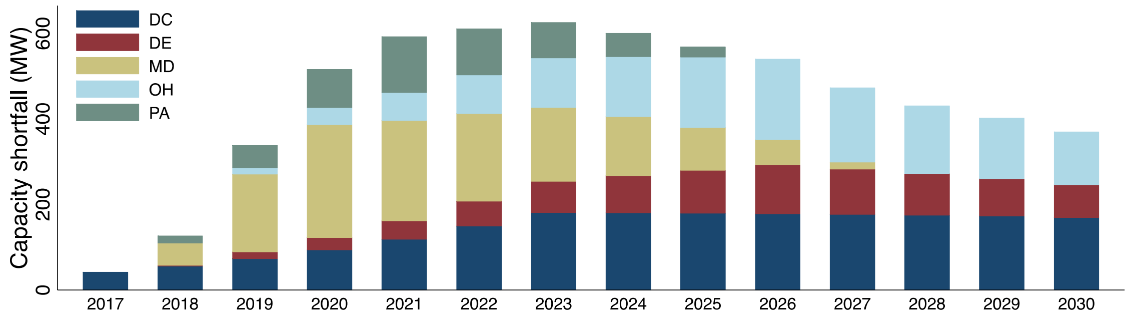


Figure 9. Projected capacity shortfalls by year in the permanent ITC effect scenario

Table 2 summarizes the sensitivity of carve-out compliance in the solar ACP states to the ITC reversion. "Robust" states have sufficient installed capacity and projections for strong future growth to ensure carve-out compliance in a post-ITC reversion environment. "Sensitive" states could experience temporary carve-out compliance issues if the ITC reversion has a substantial and persistent impact on solar deployment. "Very sensitive" states could experience long-term carve-out compliance issues in a permanent ITC effect environment.

Table 2. Summary of Carve-Out Compliance Sensitivity to ITC Reversion by Solar ACP State

State	Sensitivity to ITC reversion	Years of potential SREC shortages (permanent ITC effect)
Delaware	Very sensitive	2017-2030
District of Columbia	Very sensitive	2018-2030
Maryland	Sensitive	2018-2027
Massachusetts	Robust	-
New Hampshire	Robust	-
New Jersey	Robust	-
Ohio	Very sensitive	2019-2030
Pennsylvania	Sensitive	2018-2025

5 Modeled Effects of ITC Reversion on PPA Prices

We performed a series of modeling analyses in NREL's System Advisor Model (SAM)[10] to examine the effects of an ITC reversion on mid-sized solar competitiveness with local electricity rates in the eight states with solar carve-outs and SACPs. We do this by calculating commercial solar PPA rates based on present-day conditions (principally installed costs, financing costs, and SREC prices), and then running a sequence of scenarios that were conceived to reflect possible realities in 2017. The goal of these analyses is to take a purely economic approach in understanding which states are particularly "sensitive" to an ITC reversion (because of low electricity rates, historically low SREC prices, and other factors) and therefore likely to experience some challenges in meeting their carve-out. Methodologies are discussed in Section 5.1, and results in Section 5.2. A more detailed discussion of assumptions and methodologies is presented in the Appendix.

We utilize a number of sources to furnish their assumptions and substantiate their results for these analyses, including interviews conducted with industry solar professionals, and several publicly available and proprietary publications. These sources will be referenced where relevant in the subsections that follow.

5.1 Assumptions and Methods

5.1.1 Caveats and Limitations

These analyses are designed to be indicative, not determinative. That is, we seek to illustrate which state markets *may* experience challenges in complying with their solar carve-outs, not determine or forecast particular outcomes. The commercial solar market is complex, and PPA prices are often deal-specific. Assigning one general PPA rate to a state simplifies this reality, but the purpose is to show general market conditions and a snapshot of an "average" commercial project.

Because there are complications in modeling markets that can not only differ greatly from one to the other, but can also be highly diverse in and of themselves, it is important to identify some limitations of these analyses upfront.

- **State Incentives:** In addition to SRECs, states may also offer any number of incentives to support the economics of solar power within their jurisdictions, including rebates, tax credits, and credit enhancements (e.g. loan guarantees). Solar projects in some states may require additional incentives beyond the SRECs to be competitive with retail electricity prices. New Hampshire, for example, offers a rebate of $0.65/W of installed capacity (not to exceed 25% of installed cost) which could be a significant driver of PPA price reductions for an awarded project in a state where SREC prices currently provide only light economic support. Regardless of these conditions, the following analyses, *do not* factor in state incentives beyond SRECs. The limited availability of funds and elevated

[10] SAM is a technology performance and economic model designed to facilitate decision-making and analysis for renewable energy projects (Gilman and Dobos 2012). SAM uses the Typical Meteorological Year 3 (TMY3) dataset of the National Solar Radiation Database (Wilcox and Marion 2008) for a particular location along with user-defined technology inputs and performance assumptions.

levels of competition can make incentive programs difficult to access, and many face uncertain futures over the next several years. Moreover, project requirements and costs associated with application, in addition to other special circumstances, may introduce changes to the modeling parameters that could make certain states less comparable to others on an "apples-to-apples" basis.

- **The Utility Rate Database and Load Profiles:** Commercial retail electricity rates will vary for each customer in a given service territory based on the rate structure in the utility tariff, and the load profile of a particular building. The SAM model allows users to download utility-specific electricity rate data from the Utility Rate Database (http://en.openei.org/wiki/Utility_Rate_Database). The Utility Rate Database did not always have the most current rate schedules and, in some cases, did not have the schedule for the particular service territory (as is the case with D.C.). In such instances, proxy schedules—either in the form of past rates or nearby service territories—were substituted. We indicate where proxy data was used in Section 5.2. Additionally, SAM allows users to run a macro that applies a utility rate to a particular load profile (based on the U.S. Department of Energy's commercial reference building models [Deru et al. 2011]) in a given location. While this capability is illustrative for analysis purposes, actual solar impacts can be highly variable, depending on site-specific load parameters, weather, solar system design, net metering regulations and the presence of additional incentives, among other factors.

- **Shared Solar:** Shared solar is an emerging model which can leverage the economics of scale to reduce installed costs and simultaneously reach a large segment of customers that may not be able to install solar on their rooftops. Accordingly, in states where this model is being used, shared solar may represent an opportunity to access new markets at competitive rates when the ITC reverts to 10%. However, shared solar potential under the ITC reversion is beyond the scope of this analysis.

5.1.2 Accounting for SREC payments in the SAM Models

SRECs can provide a critical revenue stream for solar projects. The most common buyers of SRECs are regulated entities that must comply with the state solar carve-out. Often, these regulated entities will purchase all the SRECs from a solar project via a 3- to 10-year fixed-price contract. Generally, the shorter the contract term, the closer that fixed-price is to the market or "spot" price of SRECs at the time the contract is executed. Longer contracts usually entail a deeper discount to the SREC spot price, but can offer project developers more revenue certainty. Interviewees for this report indicate that three-year SREC contracts are highly prevalent today, though this exposes project developers to some merchant risk in the backend years of SREC generation (years 4–10). According to these interviewees, developers may account for this backend revenue by assuming that SREC prices will be—conservatively—75%–80% of the SACP in each of the years 4–10. Though there is no contract for this anticipated income, developers may input it into their project models when determining the price at which they can reasonably sell the energy from their project (i.e. the PPA price).

In the SAM analyses conducted for this report, we account for SREC income in two ways: 1) we discount the most recently available SREC spot price for each state by 10%[11] and enter this value into SAM as a state-level, taxable production-based incentive at a three-year term; 2) to account for the SREC revenue in years 4–10, we assume a payment of 20% of the SACP for every SREC generated in years 2018–2024.[12] We calculate the present value of these payments by discounting the revenue stream by the project internal rate of return (IRR) (7.5%), and enter this lump sum into SAM as a state-level, taxable investment-based incentive. While accounting for this revenue stream as an upfront payment can skew its value and therefore the effect on PPA price in SAM, we mitigate this effect by accounting for the time value of money in the present value calculation.

5.1.3 PPA Calculations

To simplify the effects of the different entities in the capital structure, we use the "PPA single owner" model in SAM. In other words, instead of attempting to model tax equity, developer equity, and back leverage in SAM, we use a high level weighted average cost of capital (WACC) of 7.5% to function as the project IRR. Projects were modeled to break even—i.e., achieve a net present value (NPV) of essentially $0.

We obtain 2015 year-one PPA prices in SAM using the set of assumptions outlined in Table 3 as well as the SREC revenue calculation detailed in the previous section. We cross-referenced these modeled rates with published PPA figures for commercial off-takers in SolSystems (2015a; 2015b; 2015c) and with information from interviews. For a summary of state-specific assumptions, see the Appendix.

[11] This percentage is based on interviews with professionals in the solar and SREC trade industries.
[12] This analysis assumes a combined ten-year payment stream for SRECs in all states (three years at 10% of the strike price, seven years for 20% of the SACP).

Table 3. Assumptions Behind 2015 PPA Prices Modeled in SAM

Assumption	Value
System Size	500 kW
Installed Cost	Variable by state*
Balance of Systems (BOS) Costs	15% of installed cost**
Installer/Developer Margin and Overhead	32% of installed cost**
Cost of Capital/Internal Rate of Return (IRR)	7.5%***
Inflation	2%/yr
PPA Escalation Rate	2%/yr
Analysis Period (PPA Term)	20 yrs
Real Discount Rate	5.39%
Federal Tax Rate	35%
State Tax Rate	Variable by state
Operations and Maintenance Costs	$15/kW/yr
Degradation Rate	0.5%/yr

*Based on a forthcoming NREL benchmarking analysis

**Based on GTM/SEIA 2015a,b,c and forthcoming NREL benchmarking analysis

***Based on an internal NREL analysis using data from Chadbourne 2014 and 2015a and 2015b.

Using these 2015 state-specific rates, we obtain 2017 PPA rates by changing the ITC input in SAM to 10% from 30%, with all other inputs remaining equal. To investigate how developers may mitigate the effects of a 10% ITC on PPA prices, we identify three areas of project cost that could potentially be reduced in 2017 and after:

- **BOS Costs:** Solar developers and installers continue to innovate means of reducing BOS costs. While module prices are expected to remain mostly flat in the near term, installed costs are projected to decline due to reductions in BOS costs.
- **Developer/Installer Margin and Overhead:** Margin and overhead expenses include the developer's selling, general, and administrative costs, office space, human resources, and operating profit (Feldman et al. 2013). GTM/SEIA 2015a, 2015b, and 2015c, as well as previous NREL analyses, have benchmarked installer margin, overhead, and profit between 30% - 38% of total installed costs. Reductions in this proportion in future years could come through corporate productivity gains and tighter profit margins, among other things.
- **Cost of Capital:** Typical tax equity returns range from 8%–10% on investments that constitute about 50% of the total project cost (Chadbourne 2015a and 2015b; Bolinger 2014). This, in combination with the developer's equity (which is commonly "back-levered," i.e., supplemented with debt at the developer level), can yield a project weighted average cost of capital (WACC) of 7.5% and above. In 2017, there will be fewer tax credits generated by solar projects, which means that tax equity players will likely make smaller investments, thus reducing the WACC. Additionally, investor

perceptions of solar project risk are continually improving with the increasing availability of performance and credit data, and this could also lead to lower project WACCs.

To obtain 2017 PPA we run a "high" and a "low" installed cost scenario for each state. These scenarios are defined by adjustments to the above-named constituent costs as specified in Table 4 below.

Table 4. Cost Reduction Amounts in the High and Low Installed Cost Scenarios[13]

Scenario	BOS Reduction	Installer Margin Reduction	Cost of Capital Reduction
High	12%	$0.10/W	50 basis points (bps)
Low	30%	$0.20/W	100 bps

Note: The level of reductions assumed in the low installed cost scenario are unlikely to occur within the 18 months from the time of this writing, but they do provide a useful benchmark against which to measure near-term progress.

5.1.4 Benchmarking Volumetric Rates and Demand Charges

PPA rates obtained through the two modeling scenarios are compared against the prevailing price of electricity in the eight states with SACPs to demonstrate how an ITC reversion would affect solar competitiveness in each of these markets. Electricity rates were obtained from the Utility Rate Database and applied to a secondary school load type with weather data[14] from a major airport in each of the solar ACP states. Using these parameters, we generated annual energy cost (per kWh) figures and divided these by the annual load, thus obtaining an *average* energy rate. We then escalate this year-one average by the inflation rate (2%) for two years to obtain a 2017 average price of energy.

In addition to energy, commercial electricity costs are typically also comprised of a demand charge (per kW), which reflects a customer's highest level of demand in a usually 15 – 30 minute period every month. Solar energy directly offsets the energy-only or volumetric charge, assuming that net metering is available at the full retail rate. Solar can have a mitigating effect on demand charges, but because of weather variability and the fact that net metering does not lower demand charges, the impact of solar on demand charges is difficult to predict. SAM does have the capability to model this impact for a solar project of a given size at a given location installed on a given building type, though this output is highly dependent on the model variables and assumptions, and is not suitable for decision-making purposes.

5.1.5 Solar Competitiveness in SACP Markets

For the purposes of this report, solar competitiveness is defined as a year-one PPA rate that falls in the shaded area between the volumetric rate (lower solid line) and the rate reflecting the modeled level of demand charge reductions (middle dashed line). This area represents the price

[13] The numbers chosen for each scenario are based on a variety of sources, including GTM/SEIA (2015a; 2015b; 2015c); SolSystems (2015b); Feldman et al. (2014); Mercatus (2015); Barbose et al. (2014); internal NREL data; and interviews with industry professionals.

[14] SAM uses Typical Meteorological Year 3 or TMY 3 files to model solar irradiance and therefore generation for a typical year in the given project location.

range at which solar can reasonably offset utility bills and therefore be considered to have economic value for the offtaker.[15]

According to our model, four of the states (Delaware, New Hampshire, Ohio, and Pennsylvania) demonstrate 2015 PPA prices that exceed the competitiveness area for 2017. This could imply that solar is not economic in these markets today, even though new builds are indeed happening there. This discrepancy may result from several factors, including, the exclusion of state incentives beyond SRECs in our analysis, the unique conditions of certain projects that are not captured in our analysis (e.g. particular load shapes, unique capital structures, the inclusion of grant money, etc.), and non-economic motivations among offtakers for going solar.

The four states where the 2015 PPA prices are not competitive with 2017 rates are characterized by recently slow solar growth rates, and thus our PPA analyses could be indicative of the challenges developers experience in these states. If the PPA rates published in this report represent average projects, then it may be that only "best-in-class" projects are being developed in these markets.

In all but two states (Washington, D.C. and Massachusetts), the shift to a 10% ITC (without altering other inputs) raise PPA rates outside of the competitive range and the cumulative reductions in the "Low" scenario are not enough to return them to that range (though Maryland and New Jersey are within $0.013). When a reduction scenario is not enough to reduce PPA rates to competitiveness, we estimate a "breakeven" SREC price (three-year contract) that would be required to bring solar PPAs to at least even with the 10% demand reduction line. For some states, that SREC price exceeds the state SACP, in which case we consider it likely that there may be some SACP use among regulated entities to comply with the RPS.

[15] There are several metrics by which to quantify and define solar competitiveness. For the purposes of this analysis competitiveness is defined as a PPA rate that can meet or undercut anticipated electricity costs in the first year of system operation. However, it may be that an offtaker would purchase solar electricity as a hedge against future increases in utility rates, even if the year-one PPA price did not meet or undercut its electricity costs. In this case, the system host would anticipate that the lifetime savings from the system would deliver positive economics, and not be so concerned with immediate impacts.

5.2 Results

5.2.1 Maryland

The Maryland solar market is characterized by tight economics, but where projects with strong fundamentals (e.g., low installed and financing costs, good resource) are being built (Graves 2015). According to the PPA analysis below (Figure 10 and Figure 11), as well as current SREC prices, Maryland has a lower installed solar cost compared to other states. Maryland has a tax credit of $0.0085/MWh for 10 years as well as a rebate of $30/kW, both of which we did not include in this analysis.

According to the analysis, in both the high and low installed cost scenarios (Figure 10 and Figure 11, respectively), 2017 PPA prices, after all cumulative reductions in installed and financing costs, do not fall within the competitiveness range. Again, these PPA figures are based on today's SREC prices—if SREC prices were to rise to $200 (for a three-year contract), then PPA rates would fall to just within the competitiveness range. $200 would be the effective cap on SREC prices in 2017, however, as this is the level of Maryland's SACP in 2017 and 2018. If SREC prices do rise to that level in the next two years, and if $200 per SREC for three years is sufficient for average projects (like the kind modeled for this report) to make competitive PPA bids to certain offtakers, then Maryland could weather an ITC reduction with minimal effect on new development in the near term.

However, Maryland's SACP diminishes by $50 every two years after 2018, bringing it down to $50 in 2023. In the face of a continually lowered ceiling on SREC prices, and in the absence of further state incentives, the solar industry in Maryland may have to aggressively compress costs over the next five years to achieve competitiveness with state electricity rates.

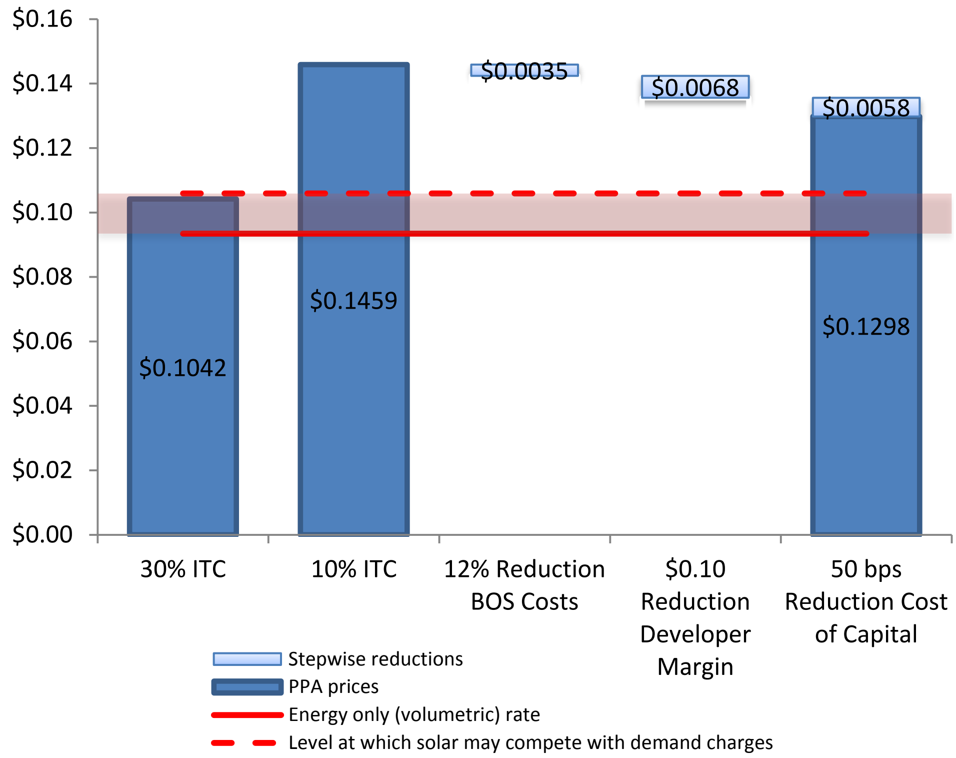


Figure 10. Maryland high installed cost scenario

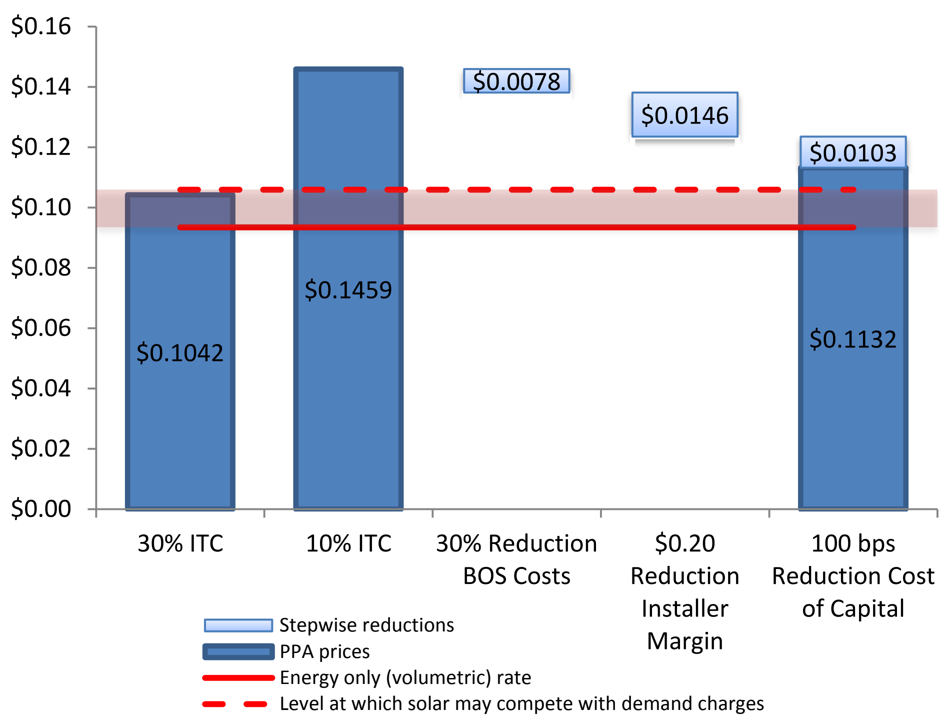


Figure 11. Maryland low installed cost scenario

5.2.2 Massachusetts

Massachusetts' high cost of retail electricity is such that the ITC reversion will likely have a minimal impact on future installations, at least in terms of solar PV's economic competitiveness (Figure 12 and Figure 13). In this particular analysis, the latest cost of electricity figures available in SAM[16] are so high and SREC prices are so supportive, that PPA prices are still 43% below the volumetric rate even after the ITC reversion. If SREC prices maintain levels commensurate with, or even slightly reduced from, today's prices, it can be reasonably anticipated that Massachusetts will be on solid footing in 2017 to fulfill its installation targets. Additionally, the Massachusetts Department of Energy Resources (MA DOER) anticipates a ramp-up in installed capacity in 2016 when developers seek to simultaneously benefit from the ITC and the remaining SRECs in the Massachusetts Solar Carve-out II program (see Section 4.2.1) (MA DOER 2015).

[16] NSTAR, the Massachusetts utility that was used to model electricity prices in this Analysis, is now Eversource. It is unclear if their rate structure has remained consistent through this change.

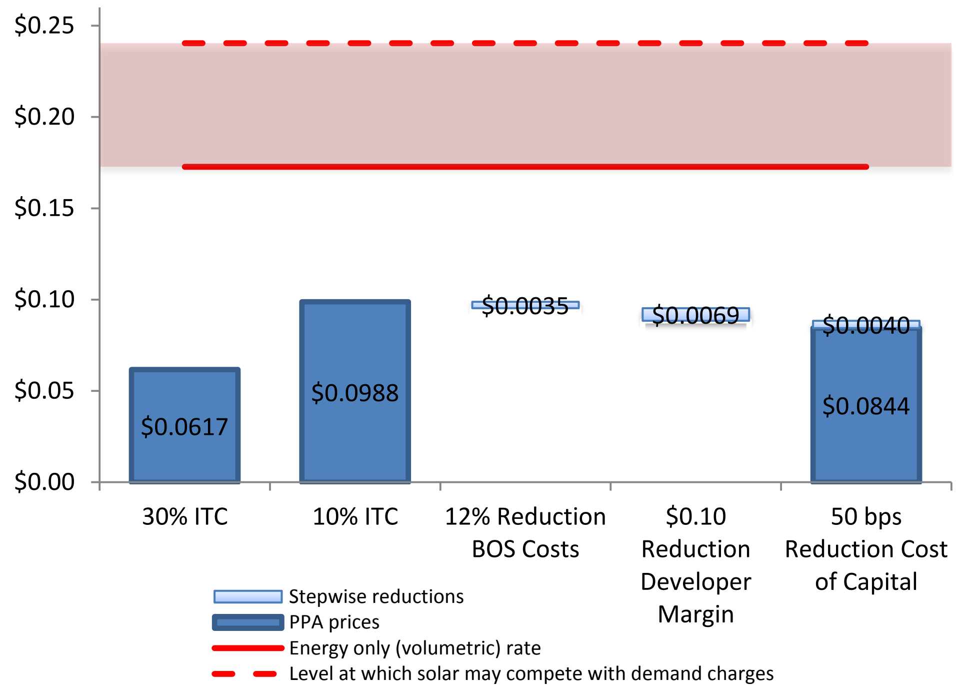


Figure 12. Massachusetts high installed cost scenario

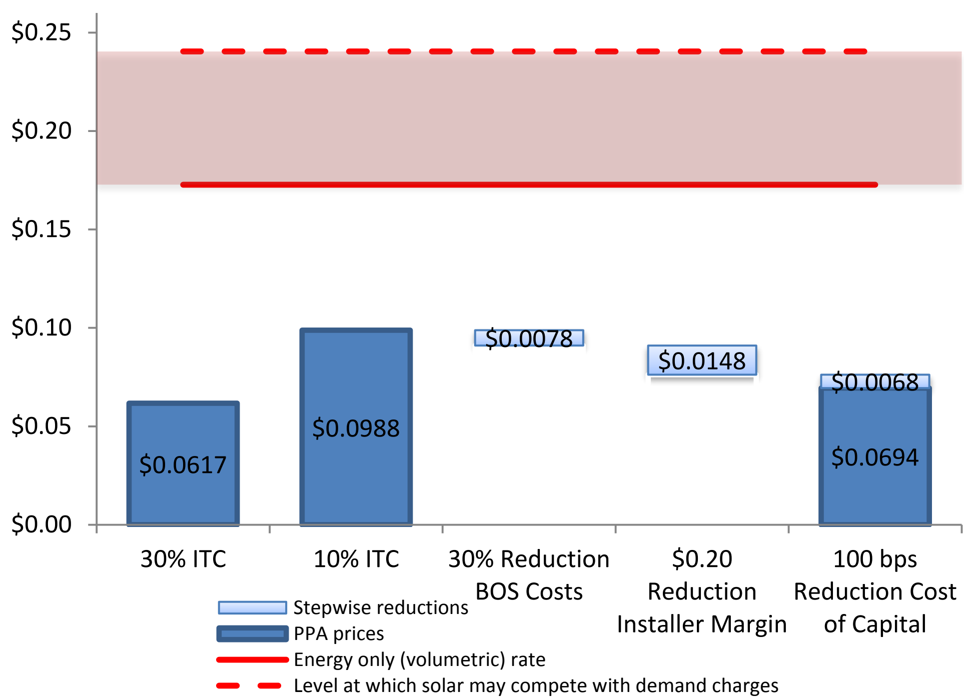


Figure 13. Massachusetts low installed cost scenario

5.2.3 New Hampshire

According to our analysis, New Hampshire's 2015 average PPA rates exceed 2017 competitiveness levels by 18% (Figure 14 and Figure 15). According to GTM/SEIA 2015c, the state's total installed capacity stood at over 7 MW as of the end of 2014, which means that at least some solar is being installed. It may be that the projects that are moving forward have access to other forms of support, including a state-offered capacity-based rebate of $0.65/W for systems larger than 100 kW but smaller than 500 kW in size (total award cannot exceed 25% of system cost). The application for this rebate closed in the third quarter of 2015, but projects that were able to access it could realize large reductions in PPA prices. When modeled in SAM, a rebate of this size brings 2015 PPA prices into the range of competitiveness, all else being equal. This illustrates the importance of additional solar strategies at the state level when SREC prices are not sufficient to drive the achievement of RPS goals.

The low installed cost scenario yields a PPA price that is still $0.03 above competitiveness levels. An SREC price of $191/MWh would be required to bring PPA prices even with the level at which solar may compete with demand charges. This far outstrips the SACP, which in 2015 was set at $55.75. Thought this would seem to indicate that New Hampshire would be sensitive to an ITC reversion, the state's target is low enough—0.3% of retail electricity sold to end-use customers—and alternative forms of support have been available (e.g., capacity-based rebates) to ensure that the state will likely meet its carve-out goals.

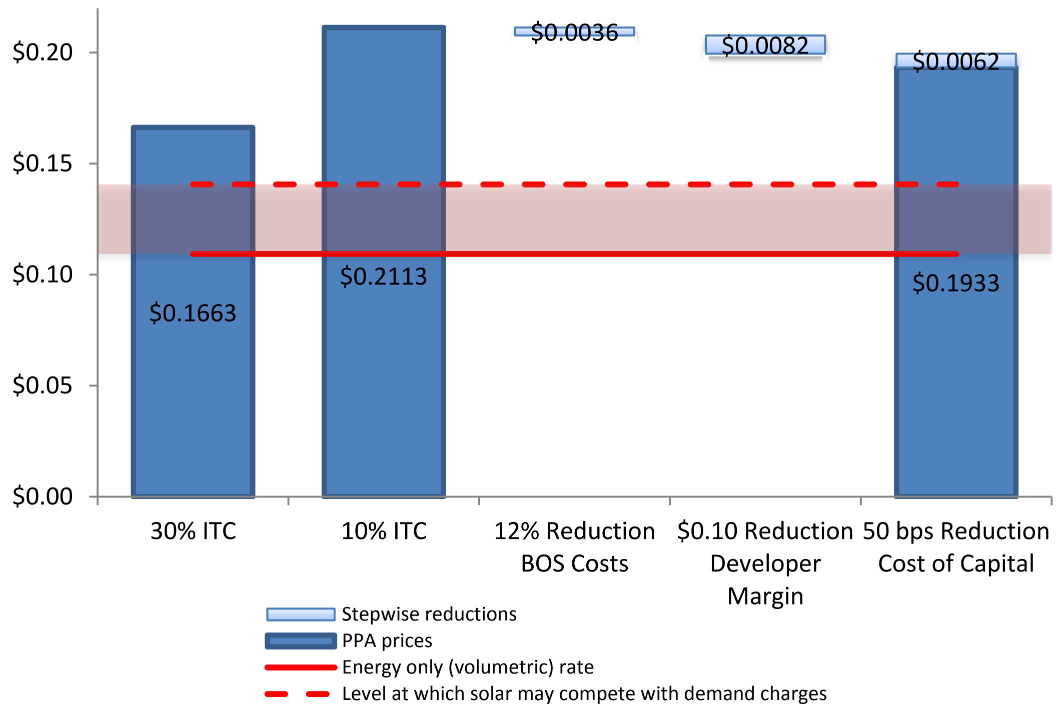


Figure 14. New Hampshire high installed cost scenario

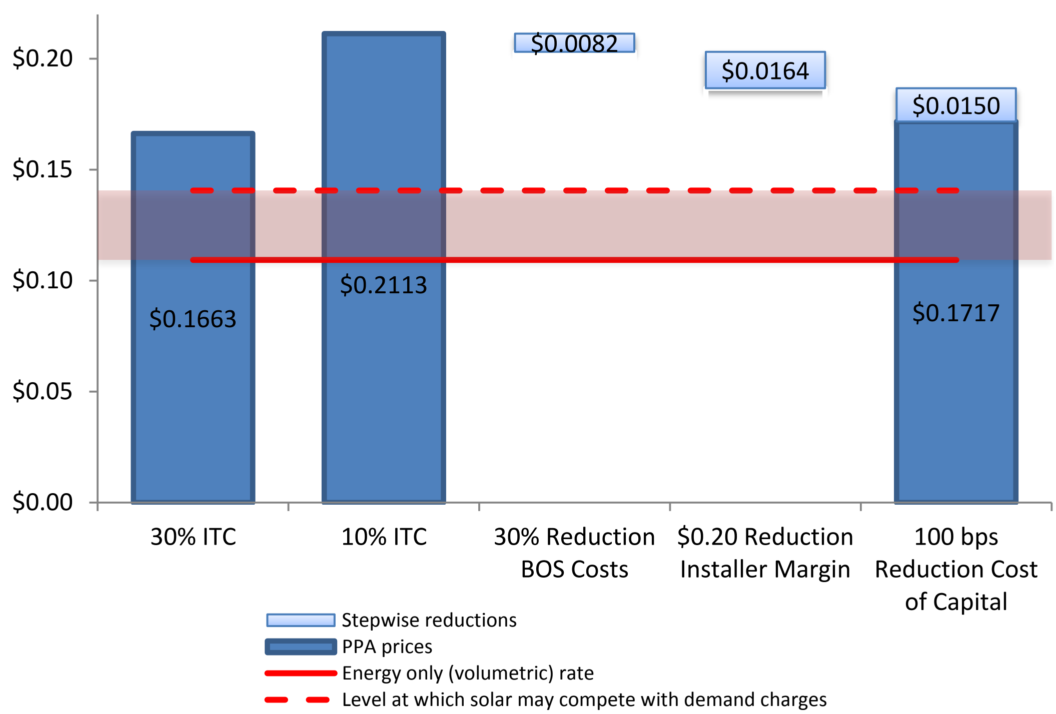


Figure 15. New Hampshire low installed cost scenario

5.2.4 New Jersey

New Jersey's SREC market has proven volatile in the past, but has stabilized in recent years, with prices reaching $207/MWh according to the most recent data available as of this writing. At that rate, an average solar project could compete with the price of commercial and industrial (C&I) electricity in New Jersey, though not necessarily by a wide margin.

The cumulative reductions of the low scenario (Figure 17) do not deliver PPA prices that fall between the volumetric rate and the 10% of demand charge line. The three-year SREC price required to close this gap is $263/MWh, which—considering that New Jersey's SACP in 2017 is set at $315 and considering that there may be a slowdown in installations and therefore a jump in SREC prices—may not be an unrealistic level for SRECs to approach. Therefore, even though the low installed cost scenario in this analysis does not deliver a competitive PPA price (according to our definition), there is enough room for New Jersey's SREC prices to increase to support ongoing development, given modest project cost reductions.

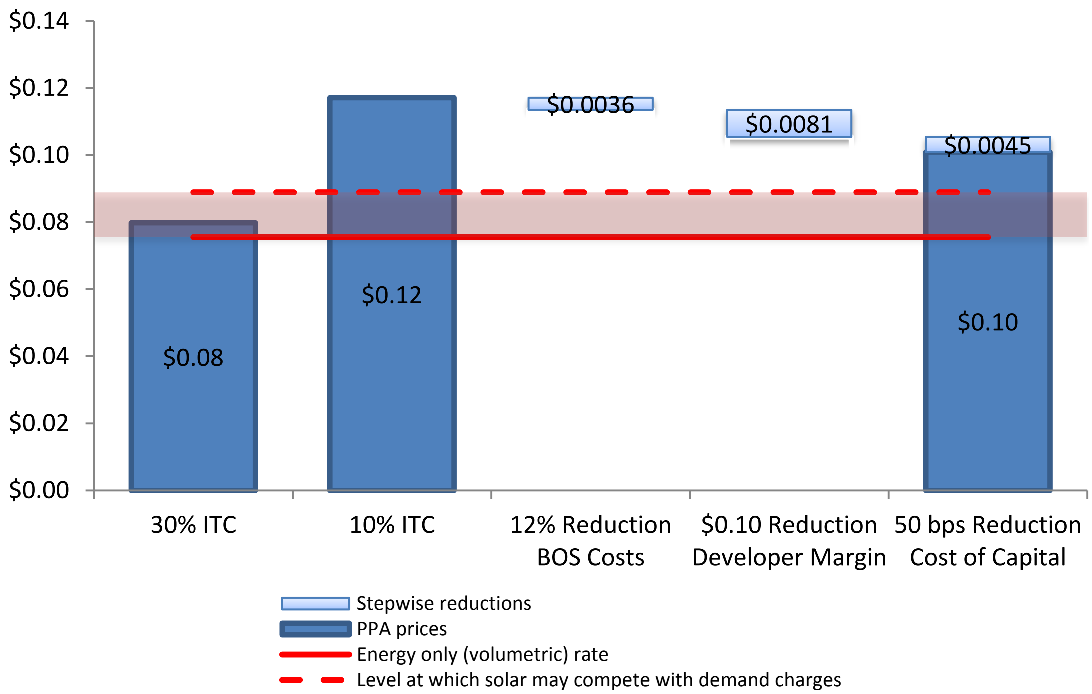


Figure 16. New Jersey high installed cost scenario

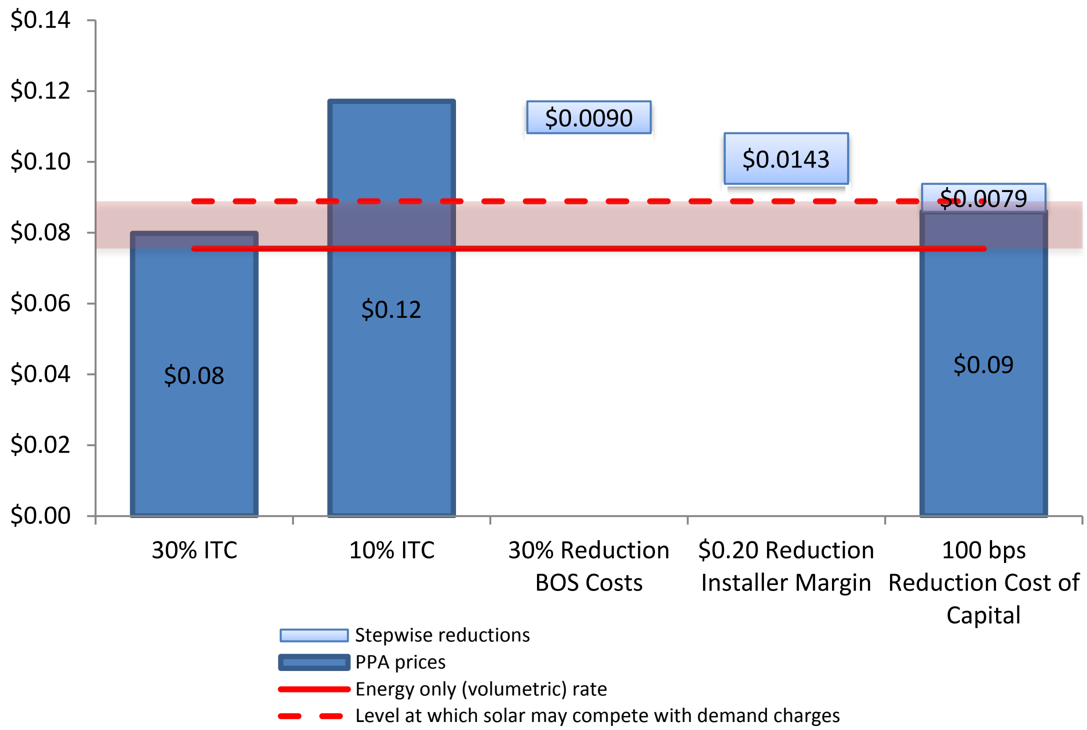


Figure 17. New Jersey low installed cost scenario

5.2.5 Delaware

Delaware has a unique SREC purchase program whereby developers bid into an auction and receive a 10-year fixed price for their SRECs, and a 10-year, fixed ($35/MWh) "back end" payment after that. In other words, the project receives a revenue stream for what could be the entirety of its PPA and this helps to exert downward pressure on PPA rates in the absence of robust SREC prices.

While Delaware's modeled PPA prices (Figure 18 and Figure 19) might be competitive in another market—say Massachusetts or California—it is difficult to match the price for C&I electricity in Delaware. According to our analysis, the volumetric rate is just above $0.05/kWh, and though there is a relatively ample bandwidth of competitiveness between the volumetric rate and the rate at which solar can compete with demand charges, the competitiveness ceiling remains too low for solar PV at current SREC levels.

GTM/SEIA 2015c indicates Delaware's total installed capacity exceeded 60 MW at the end of 2014, which is appreciable for a small state (in terms of population and landmass). Clearly there is a market for solar PV in the state today. Going forward, robust ten-year SREC prices ($105/MWh is the "breakeven" SREC price for the low scenario, according to our analysis), load profiles particularly sensitive to solar offsets, and continued cost reductions may be among the principal driving forces behind PV adoption in the wake of an ITC reversion.

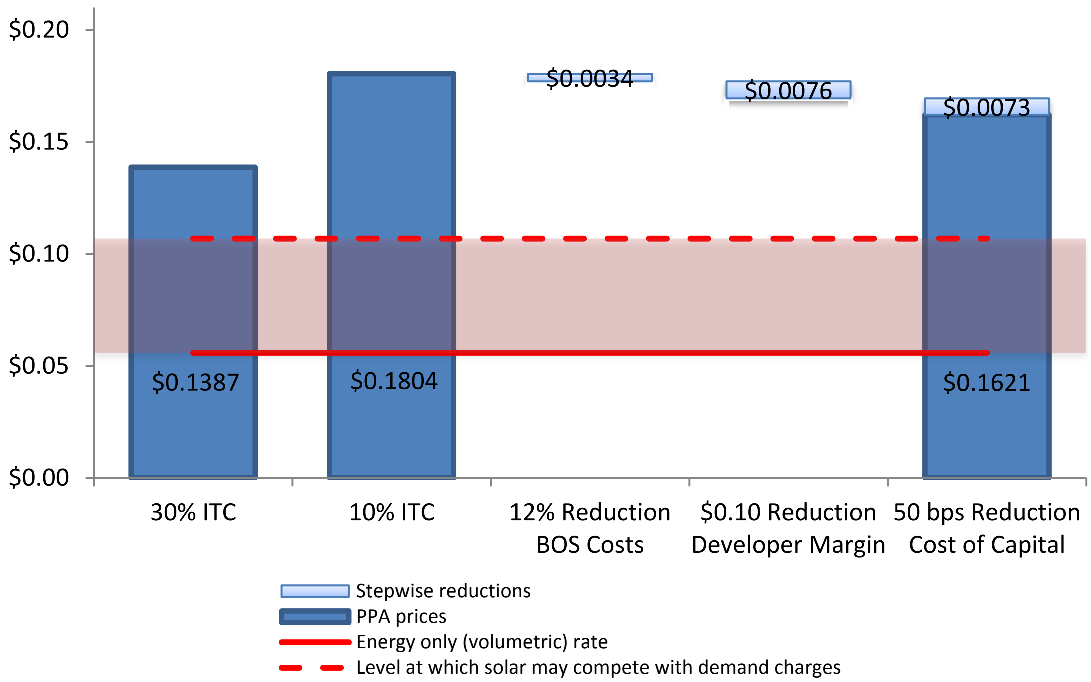


Figure 18. Delaware high installed cost scenario

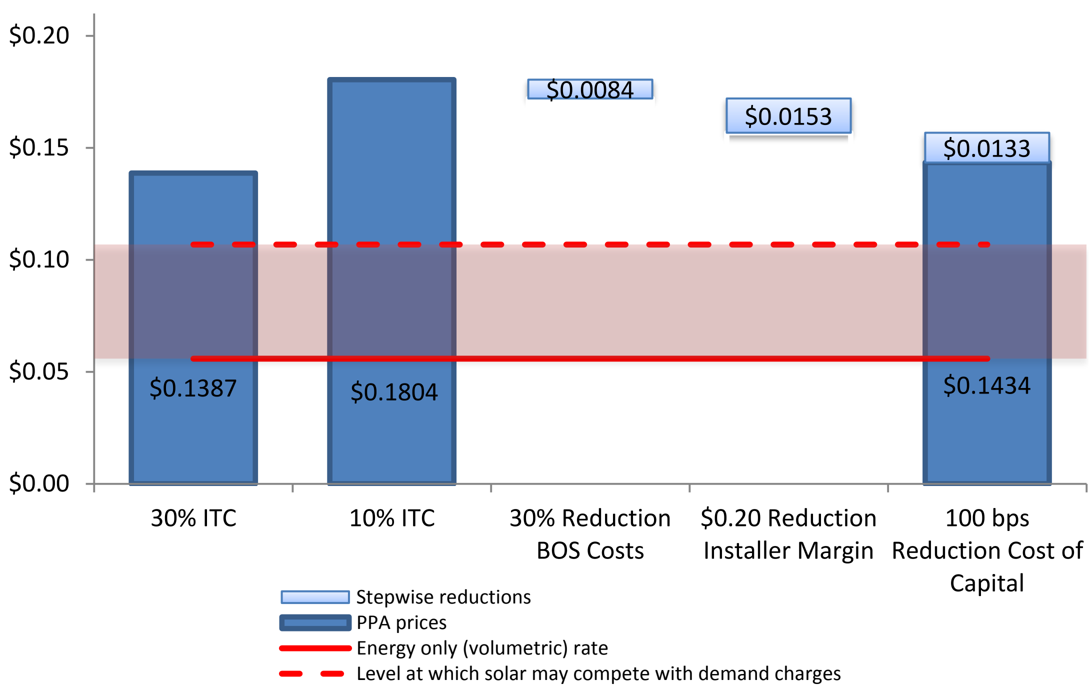


Figure 19. Delaware low installed cost scenario

5.2.6 Ohio

In 2014, Ohio's governor signed legislation to freeze the state's RPS compliance path, which has kept Ohio's solar development and SREC prices flat for the last year. Low commercial electricity prices exacerbate challenges for solar developers in Ohio. NREL interviews with solar financiers working in Ohio revealed that some solar projects are proceeding with development and installation, but these projects were said to be smaller than the 500 kW project modeled for this analysis (interviewees pegged the range of viable projects in Ohio at 50–100 kW). Smaller projects can access a higher price of electricity which helps to enable competitiveness in an environment where SREC prices are around $15/MWh.

Given these challenges, Ohio may be a state that is particularly sensitive to an ITC reversion (Figure 20 and Figure 21). Therefore, even with the RPS freeze in place, some SACP use among RPS-compliant entities may result if solar development for average projects becomes uneconomic in 2017.

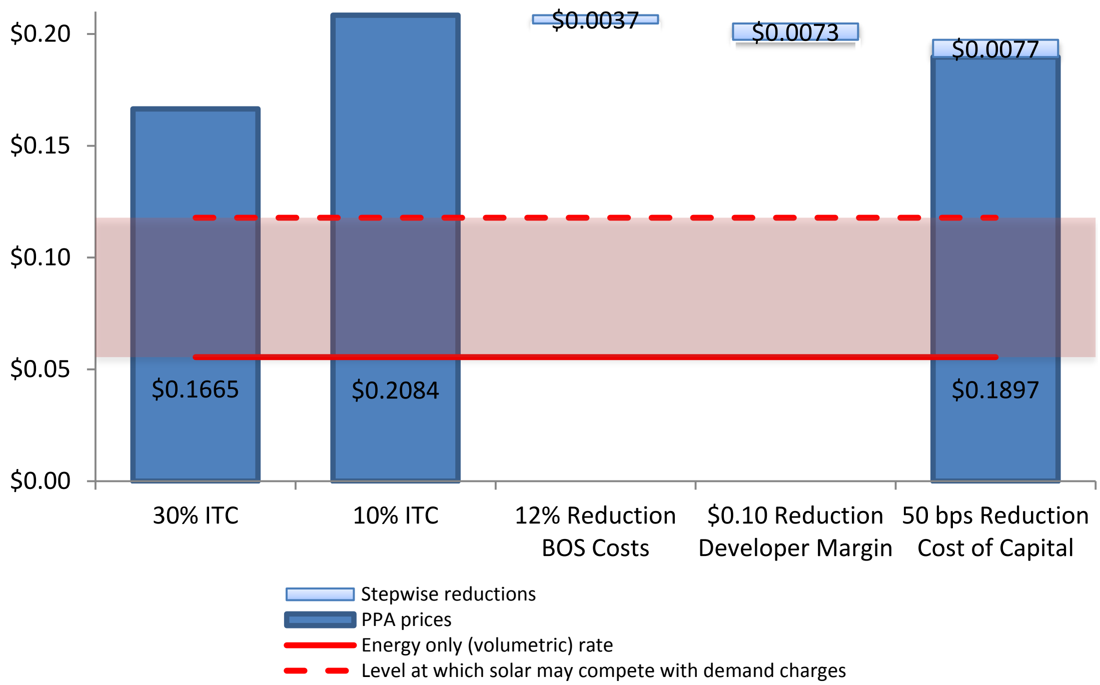


Figure 20. Ohio high installed cost scenario

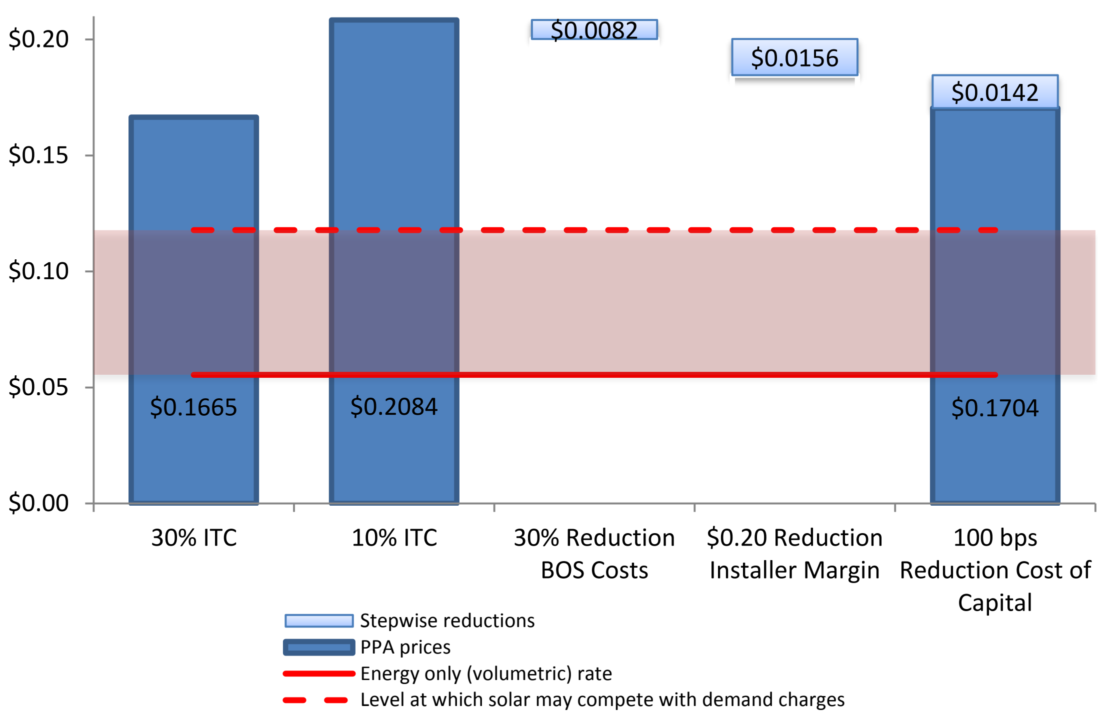


Figure 21. Ohio low installed cost scenario

5.2.7 Pennsylvania

Pennsylvania's SREC markets experienced a brief surge up to $60/MWh in January 2015, but as of August 2015, SREC prices had fallen to $13.50/MWh. The state's SREC prices have trended low over the last several years, partly because Pennsylvania allows out-of-state credits to be used for RPS compliance. As such, Pennsylvania has historically been an oversupplied SREC market. As such, it is unlikely that SREC prices could reach SACP levels.

According to our analysis (Figure 22 and Figure 23), SRECs of $290/MWh for three years would be the lowest price required for the PPA rate to fall within the range of competitiveness (i.e. for the low cost scenario). This, however, is not a realistic outcome given the open nature of Pennsylvania's SREC market, and the fact that the SACP for 2017 is $200.

Given these conditions, it is likely that regulated entities in Pennsylvania will continue to use out-of-state SRECs for solar carve-out compliance. This may prevent use of the SACP among compliant entities, but it also may keep development at low levels, especially after the ITC goes to 10%.

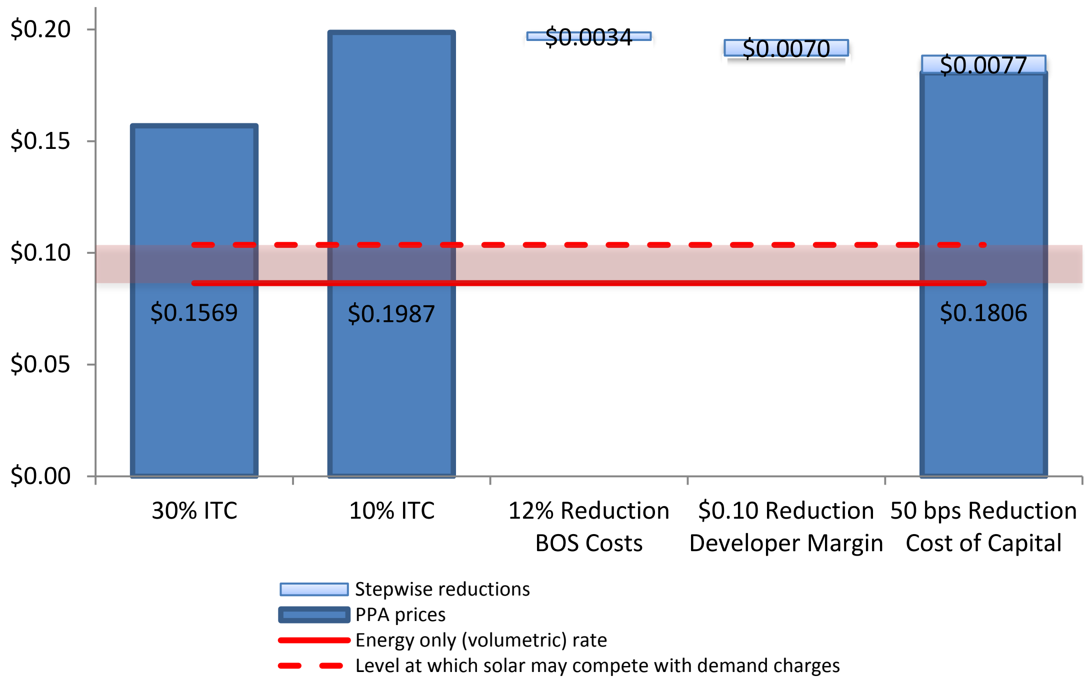


Figure 22. Pennsylvania high installed cost scenario

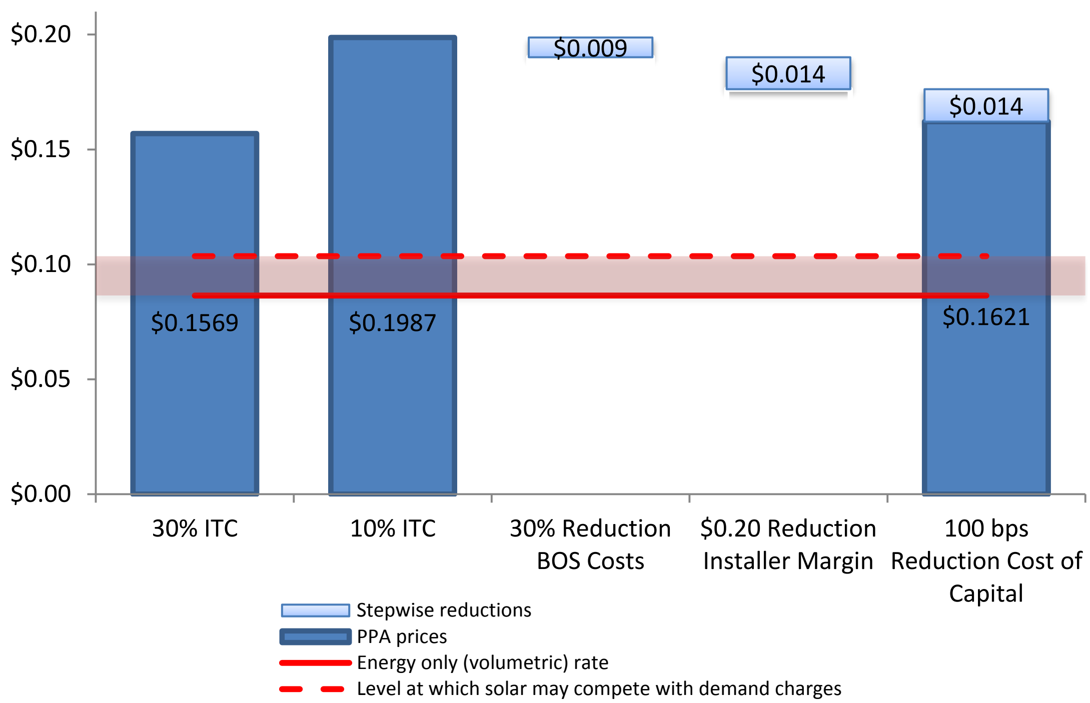


Figure 23. Pennsylvania low installed cost scenario

5.2.8 Washington, D.C.

Washington, D.C. is an especially unique market given the siting challenges—limited roof space, a large collection of historic buildings that may be undevelopable or have difficult permitting requirements—and the requirement that all qualifying projects be located within the district. The Washington, D.C. SREC market was undersupplied in 2015, which has driven prices up to $436/MWh as of September 2015. At those levels and an installed cost of $2.62/W, our break-even PPA price is below $0.05/kWh (Figure 24 and Figure 25). As in Massachusetts, the ITC reversion does not impact PPA competitiveness. Siting challenges, however, will likely continue to beset this market and make it difficult for developers to take advantage of the SREC price.

It should be noted that electricity data for Washington, D.C. is not available in the Utility Rate Database. Therefore, we used proxy data from PEPCO in Maryland to construct the competitiveness range. PEPCO also serves Washington, D.C., though it is likely that the rates between the two different territories will vary. However, even if PEPCO's rates for Washington, D.C. are lower than those for Maryland, the economics of solar projects that can clear siting hurdles in Washington, D.C. are robust enough—owing to the SREC price—that solar would still likely be competitive.

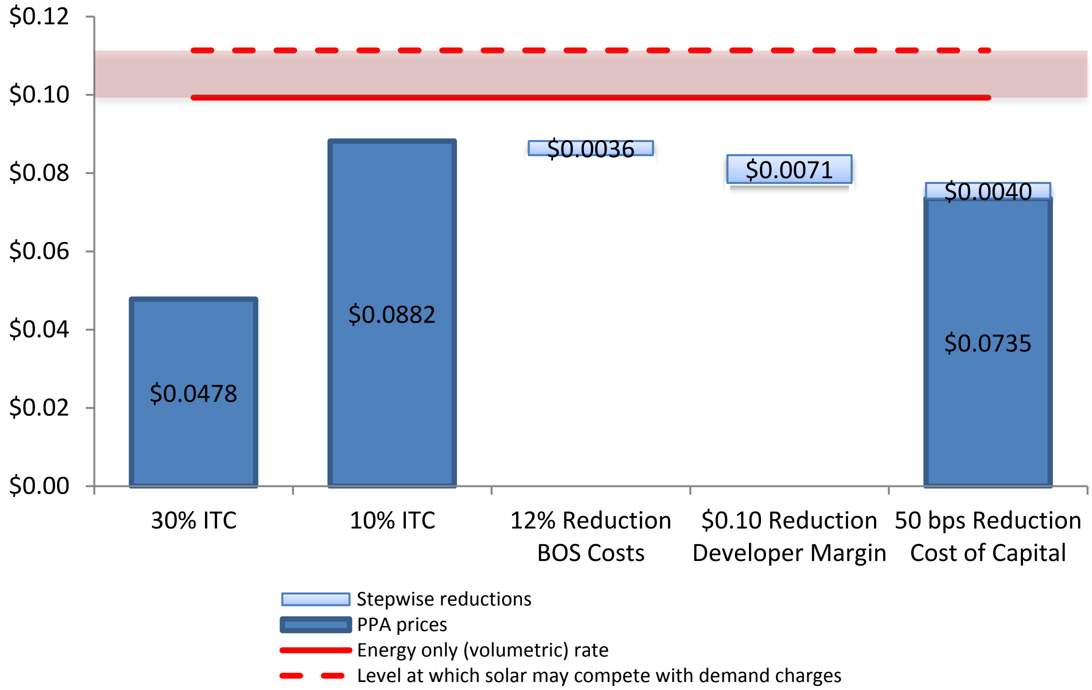


Figure 24. Washington, D.C. high installed cost scenario

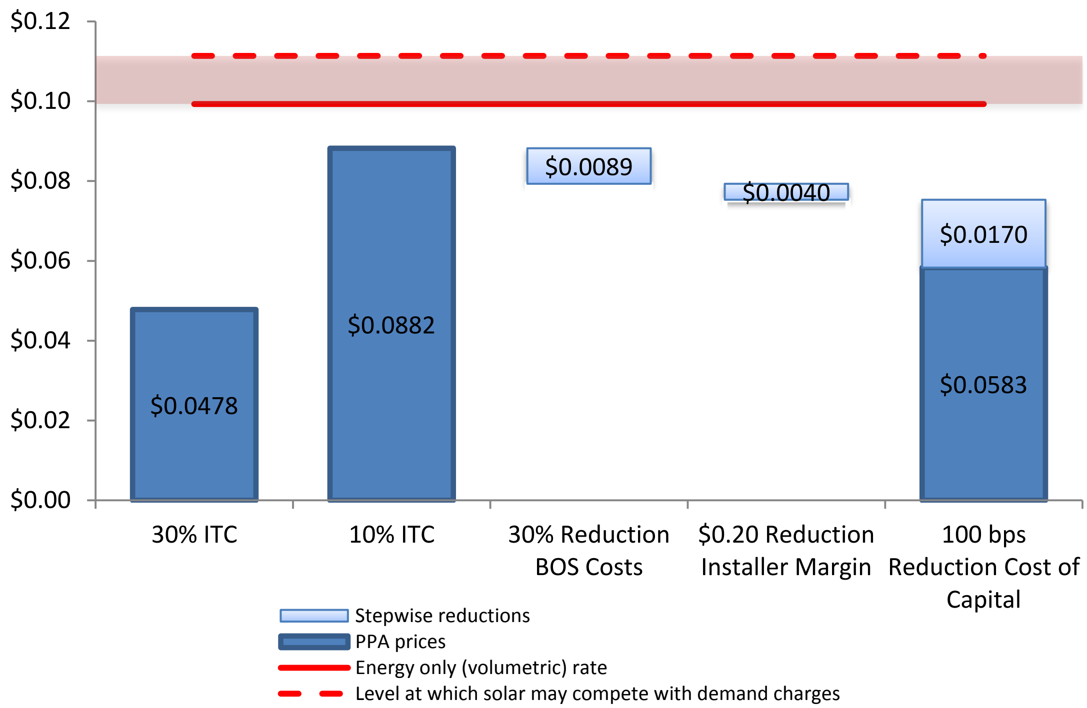


Figure 25. Washington, D.C. low installed cost scenario

6 Summary and Conclusions

In order for RPS solar carve-outs to be met, solar deployment will need to increase. If the ITC reversion causes long-term or even temporary deployment constraints in annual installed capacity, as some analyses posit, SRECs could be in shorter supply, resulting in regulated entities using SACPs for carve-out compliance.

Forecasts of near-term solar deployment vary. GTM (2015) projects installations to decrease in 2017 then rebound in years 2018–2020 to levels exceeding 2016 installations. EIA (2015) analysis shows installed capacity falling in 2017 and then remaining nearly flat in years 2018–2040. Based on these installation projections and solar deployment needed to meet carve-outs, shortfalls could exist in Washington, D.C., Delaware, Maryland, Ohio, and Pennsylvania if installations do not rebound after 2017.

As discussed in the introduction, two related factors will determine future carve-out compliance in the solar ACP states in a post-ITC reversion environment. 1) the sensitivity of states to capacity reductions associated with the ITC reversion (Section 4) and 2) the sensitivity of solar project economics to increased revenue requirements following the ITC reversion (Section 5). Table 5 summarizes the two factors by state.

Table 5. Summary of Sensitivity of State Solar Carve Outs to ITC Reversion

State	Sensitivity to capacity reductions	Sensitivity of project economics	Overall sensitivity to ITC reversion
Delaware	High	High	High
District of Columbia	High	Low	Medium
Maryland	Medium	Medium	Medium
Massachusetts	Low	Low	Low
New Hampshire	Low	Medium	Low
New Jersey	Low	Medium	Low
Ohio	High	High	High
Pennsylvania	Medium	High	Medium

Overall, our analysis suggests that the sensitivity of carve-out compliance to the ITC reversion is modest in six of the eight states. Current installed capacity in most of the solar ACP states place carve-out programs on a trajectory for future compliance, especially given projections of continued growth (GTM 2015). However the results of Table 5 present a simplified analysis that doesn't account for state-specific contexts that will ultimately determine post-ITC reversion carve-out compliance. The remainder of this section summarizes the results of our analyses by state carve-out program.

States with overall High sensitivity to ITC reversion:

- In Delaware, solar deployment projections indicate that SREC supplies may be sensitive to the ITC reversion. The state's long-term SREC contract program provides a 20 year contract, with 10-year auction-based price for the SRECs and 10-year back end payment of $35/MWh. The long-term revenue certainty helps exert downward pressure on PPA rates. However, our SAM analysis found that given the low commercial electricity prices in the state, SREC prices would need to reach $105/MWh – 130/MWh in order for commercial solar PPAs to compete with projected 2017 electricity prices. These SREC prices are significantly higher than current prices of around $40/MWh, but much lower than the 2017 SACP of $400/MWh.

- In Ohio, solar carve-out compliance is projected to be met under a temporary ITC effect scenario. However, looking purely at in-state economics of commercial solar systems, our analysis finds that SREC prices would need to exceed the 2017 SACP in order for solar PPA prices to be lower than commercial electricity rates. Current SREC prices are less than $20/MWh, indicating that compliance is coming from out-of-state solar resources. Future compliance will likely be met with out-of-state resources. The carve-out was frozen by SB 310 at 0.12% of retail sales but is set to increase to 0.15% in 2017.

State with overall Medium sensitivity to the ITC reversion:

- Washington, D.C. had some of the highest SREC prices, at greater than $400/MWh, since closing the market to out-of-district generators in 2011. Both deployment scenarios show potential shortfalls in needed capacity to meet the carve-out in 2017, likely due to the siting challenges in the District. However, our SAM analysis shows that commercial solar PPAs would be lower than projected 2017 electricity prices at SREC prices lower than current levels.
- In Maryland, solar deployment projections indicate that the carve-out could be sensitive to the ITC reversion. SREC prices would need to rise to $200/MWh, which is consistent with current SREC prices but bumping up against the 2017 SACP of $200/MWh.
- Pennsylvania's solar market is similar to Ohio's, with low SREC prices and use of out-of-state solar to meet the carve-out. In a low deployment future scenario, SREC capacity may not be able to be met with in-state resources. Our SAM modeling shows that under both the high and low cost scenarios, SREC pricing would need to exceed the SACP in order for a commercial solar PPA to be lower than projected 2017 electricity prices.

States with overall Low sensitivity to the ITC reversion:

- In Massachusetts, high and low deployment scenarios project compliance with the solar carve-out. Our SAM scenario analysis shows that under high and low solar cost scenarios, commercial solar PPAs would be lower than projected 2017 electricity prices. However the ITC reversion could affect future carve-out compliance through program attrition. The Massachusetts 1,600 MW requirement is based on "qualified" capacity, i.e., projects that have met the minimum requirements necessary to generate program-compliant SRECs. The ITC reversion could affect the economic viability of some qualified projects and ultimately prevent project implementation. Such program attrition would cause a capacity shortfall and a temporary shortage of SRECs.
- In New Jersey, projected installed capacity in the low installed cost scenario is enough to ensure compliance with the solar carve-out. In the high scenario, an SREC price of $263 would be required to drive solar competitiveness, but this may be a reasonable level for

SRECs given the SACP of $315 in 2017 and the fact that solar development is likely to slow in a 10% ITC market, thus pushing SREC prices up.

- New Hampshire's solar economics do not look to be competitive based on our analysis, though projects that are able to take advantage of a state rebate will likely be able to compete with the low electricity prices. With a low carve-out target (0.3%) and the continued existence (even if limited) of state rebates, New Hampshire will likely not meet with many challenges in achieving their solar carve-out.

State incentives (other than SRECs) play a critical role in determining the economics of solar-generated electricity in some states. The degree of PV competitiveness (or non-competitiveness) in these states will depend on the availability and the levels of these incentives in a post-30% ITC environment. In Maryland, for example, the loss of the state tax credit and rebate could have a significant impact on solar project economics, such that SREC prices matching or exceeding the SACP would be required to produce competitive PPA prices.

Though our focus of the SAM analysis is on commercial scale solar, residential and utility scale solar also contribute to solar carve-outs. State policies focused on these other segments, for example, net metering program caps, could also impact solar carve-out compliance. In response to nearing its net metering program cap, and in recognition that they wanted to incentivize maximum deployment solar before the ITC reversion, legislators in Vermont raised the net metering program cap from 4% of peak demand to 15%.

The ITC reversion is not the only factor that could influence carve-out compliance. Other considerations such as carve-out size, net metering, and rate redesign can impact the economic viability of solar energy in a given state. The interplay of these factors will be critical in determining the impact of the ITC reversion on solar deployment.

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Appendix: Detailed Discussion of Assumptions and Methods

The methodologies used to calculate PPA prices and electricity rates were based on the input of a number of sources both internal to NREL and in the solar development community. We sought the review of developers and financiers before, during, and after the analyses were performed to ensure that our figures were defensible and, where possible, in line with market realities. However, the analyses do not include state incentives and only analyze one type of commercial building in one utility service territory per state, thus limiting our scope.

Three significant aspects of these analyses are:

1. PV system costs
2. SREC prices
3. Electricity costs

Regarding system costs: it is difficult in a rapidly changing and fractured market such as solar to benchmark inputs such as system costs and their constituent proportions (e.g. BOS costs, developer margin). Therefore, the cost data used in this report may diverge from some realities on the ground and/or become quickly outdated. However, we have found that the sources indicated beneath Table 1 provide a credible portrait of the solar market today, and are confident that the numbers expressed in this report generally reflect the state of affairs in 2015.

Forward SREC prices are especially difficult to forecast, and, as such, we chose not to assume 2017 prices. We instead assume today's prices to model future projects, which may skew our 2017 scenarios, but in the absence of robust projection data, we opted to not make our own assumptions. It is reasonable to expect that any contractions in PV development resulting from the ITC reversion, rate redesign, changes to net metering regulations, and other effects would put upward pressure on SREC prices in 2017 and beyond. Thus, the assumption that SREC prices will be equivalent to 2015 levels in 2017 can be regarded as conservative for some markets.

In applying our methodology to value the backend of SREC revenue (years 4 – 10) some cases yielded 80% SACP discounts that were still above today's SREC prices on a per unit basis. For example, in Pennsylvania, the latest SREC figures we use for this report are $13.50/MWh. However, the backend revenue stream is valued at $50,274 according to the methodology described above, which would yield an SREC price of $75/MWh in year 4. While this proves a limitation in the analysis, we chose not to modify SREC valuation methodologies state by state so as to preserve an "apples-to-apples" basis of comparison.

Determining electricity costs for commercial customers is a complex undertaking because of the various charges, customer classifications (often a commercial customer may qualify for more the one schedule), and the site- and building-specific load characteristics. Commercial utility bills are typically some combination of an energy charge (per kWh), a demand charge (per kW, usually assessed by the highest level of load within a 15–30 minute period every month), a fixed charge (per month), and a host of riders and add-ons that inflate the energy charge. In addition to these elements, rates can vary temporally or based on consumption. Time-of-use (TOU), seasonal, and tiered or block rate structures will alter the amount of each charge to reflect the utilities costs in serving customers during peak intervals, and/or to inform particular consumption patterns (e.g. tiered rates can be discouraging to high energy use).

We chose secondary school as the load type (i.e. the PPA offtaker) because, among other reasons: 1) the coincidence of solar generation and modeled peak load, as well as the size of the modeled load, are such that they would make a large solar system economic for the offtaker; 2) it is common for universities to have enough available rooftop space or land to host a 500 kW system. We do not vary the building type for any of the analyses, but instead use the secondary school as a representative load type for all states. A forthcoming NREL analysis on breakeven conditions for commercial solar installations (Davidson and Gagnion 2015) provides a look at the effect that building types and thus load shape have on the economic viability of mid-scale solar across the United States.

Below are the tables of state-specific assumptions used in the SAM analyses. All installed costs are outputs from an NREL internal model designed to benchmark system costs in all 50 states. The proportions of BOS costs and installer margin were reconciled from percentages derived from GTM/SEIA 2015a, 2015b, and 2015c as well as from the NREL model.

Table A-1. Maryland Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Baltimore/Washington Int'l Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	Baltimore Gas and Electric GL (Secondary Voltage)		
BOS Costs	$0.38/W	$0.33/W	$0.27/W
Installer Margin	$0.81/W	$0.71/W	$0.61/W
Installed Cost	$2.53/W	$2.39/W (after all cost reductions)	$2.21/W (after all cost reductions)
SREC Price (3-year contract)	$164/MWh		
NPV SREC Revenue (years 4–10)	$85,268		

Table A-2. New Jersey Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Newark International Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	PSEG Secondary Bundled		
BOS Costs	$0.39/W	$0.34/W	$0.27/W
Installer Margin	$0.83/W	$0.73/W	$0.63/W
Installed Cost	$2.53/W	$2.44/W (after all cost reductions)	$2.28/W (after all cost reductions)
SREC Price (3-year contract)	$207/MWh		
NPV SREC Revenue (years 4–10)	$191,515		

Table A-3. Massachusetts Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Boston Logan International Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	NSTAR* B-2 G-2		
BOS Costs	$0.40/W	$0.36/W	$0.28/W
Installer Margin	$0.86/W	$0.76/W	$0.66/W
Installed Cost	$2.69/W	$2.54/W (after all cost reductions)	$2.37/W (after all cost reductions)
SREC Price (3-year contract)	$279/MWh		
NPV SREC Revenue (years 4–10)	$211,515		

*Now Eversource

Table A-4. New Hampshire Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Boston Logan International Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	PNSH* LG Large Commercial & Industrial		
BOS Costs	$0.38/W	$0.34/W	$0.27/W
Installer Margin	$0.82/W	$0.72/W	$0.62/W
Installed Cost	$2.55/W	$2.40/W (after all cost reductions)	$2.23/W (after all cost reductions)
SREC Price (3-year contract)	$45/MWh		
NPV SREC Revenue (years 4–10)	$36,038		

*Now Eversource

Table A-5. Pennsylvania Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Philadelphia International Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	PECO GS		
BOS Costs	$0.40/W	$0.35/W	$0.27/W
Installer Margin	$0.84/W	$0.74/W	$0.64/W
Installed Cost	$2.64/W	$2.49/W (after all cost reductions)	$2.32/W (after all cost reductions)
SREC Price (3-year contract)	$13.50/MWh		
NPV SREC Revenue (years 4–10)	$50,274		

Table A-6. Washington, D.C. Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Washington, D.C. Reagan Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	PEPCO of Maryland General Primary Service GS3A*		
BOS Costs	$0.39/W	$0.35/W	$0.28/W
Installer Margin	$0.84/W	$0.74/W	$0.64/W
Installed Cost	$2.62/W	$2.47/W (after all cost reductions)	$2.30/W (after all cost reductions)
SREC Price (3-year contract)	$436/MWh		
NPV SREC Revenue (years 4–10)	$114,996		

*Rates for PEPCO DC are unavailable on the Utility Rate Database

Table A-7. Ohio Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Columbus Port Columbus International Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	City of Columbus KW31 (Large Commercial Churches and Schools)		
BOS Costs	$0.39/W	$0.35/W	$0.28/W
Installer Margin	$0.84/W	$0.74/W	$0.64/W
Installed Cost	$2.64/W	$2.48/W (after all cost reductions)	$2.31/W (after all cost reductions)
SREC Price (3-year contract)	$15.30/MWh		
NPV SREC Revenue (years 4–10)	$51,040		

Table A-8. Delaware Assumptions

Input	2015 Analysis	2017 High Scenario	2017 Low Scenario
Project TMY Location	Dover Airport		
Project Size	500 kW_{dc}		
Load Profile	Secondary School		
Rate Schedule	City of Columbus KW31 (Large Commercial Churches and Schools)		
BOS Costs	$0.39/W	$0.35/W	$0.27/W
Installer Margin	$0.83/W	$0.73/W	$0.63/W
Installed Cost	$2.58/W	$2.43/W (after all cost reductions)	$2.26/W (after all cost reductions)
SREC Price (3-year contract)	$36.90/MWh		
NPV SREC Revenue (years 4–10)	$58,354		