Economic Drivers of PV Report for ISO-New England

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Exhibits

1. EXECUTIVE SUMMARY

1.1 Purpose

The topic of solar photovoltaic (PV) economics attracts a great deal of attention and discussion, especially in areas with rapidly growing penetration of PV like New England. While the future path of PV deployment is unknown, that path will be heavily influenced by how the economic building blocks or drivers that determine the cost-effectiveness of PV change. Those drivers include technology cost and performance; Federal incentive policies; renewable energy credit (REC) markets; state, local, and utility policies; financing mechanisms; and wholesale and retail electricity markets. To inform the review of PV deployment paths in New England, this analysis conducted by consultancy ICF International for ISO-New England (ISO-NE) quantifies economic drivers of PV and how those drivers differ by state, by customer type, and over time. The relative contribution of each driver is provided under the simplifying and standardized assumptions of this analysis. While this report offers neither forecasts of PV capacity deployment nor electricity production, its analytic framework and observations are intended as a backdrop for forecast deliberations. The study results show major trends and factors affecting PV development; they do not represent precise dollar values.

1.2 Methods

This analysis uses a 25-year discounted cash flow model to calculate the estimated impact of 16 different economic "drivers" on PV economics. These drivers include installed costs of projects, the Federal investment tax credit, wholesale and retail electricity prices, REC prices, and low-cost debt. Results are presented as levelized per kilowatt-hour (kWh) impacts of each driver in present value terms. Summary measures, such as the economics of PV without any policy or financing support, with only Federal support, and with a full range of support, are also provided. Results are calculated for residential, commercial, and utility scale PV projects in each of the six New England states and for projects beginning in 2015, 2019, and 2024. In addition to a full set of results using the study's baseline assumptions, a partial set of alternative scenario results are presented in association with five state incentive policies with program goals that extend to at least 2019 but for which 2019 and 2024 incentives levels have not been established or are not readily available.

1.3 Summary of Results

Due to the large number of outputs presented (16 economic drivers across 54 combinations of state, customer type, and project starting year), there is a wide range of potential findings from this work. These findings should be tempered by the limitations of the analysis, as highlighted on the next page and described in more detail throughout the report. Key findings include:

- Projects beginning in 2015 should continue to offer strong investment returns for customers in many parts of New England if the project owner can access available Federal and state incentives and financing mechanisms. Many of the same factors and policies that contributed to large amounts of PV deployment in New England in 2014 are assumed to remain in place in 2015.

- The planned decline of the Federal investment tax credit (ITC) beginning in 2017, together with the planned reduction of some state PV policy support, creates somewhat more challenging overall PV economics in 2019 and 2024 in virtually all markets.

- The unaided (by Federal and state policy support) economics of PV continue to improve over time. This is because PV installed costs are forecast to continue declining in real dollars, PV performance is assumed to improve, and the physical electricity (wholesale and retail) prices received for PV output should continue to increase. However, the results generally show that the combined effect of these positive financial influences (as assumed) is not sufficient to entirely counteract the impact of the planned reduction of the Federal ITC. For projects beginning in 2019, the decline in PV economics was most significant when reductions in state policy support were also assumed for policies without proscribed future values, but it persisted even when state policy support remained constant at 2015 levels for these policies.

- For PV projects that begin after the Federal ITC declines in 2017 and that do not have access to key state policies (e.g., SREC premia over Tier 1 RECs or long-term tariff or auction procurement rates), resulting PV economics rely significantly on the study's assumed continuation of state net metering policies in their current form. Existing aggregate net metering caps were assumed not to become constraints on PV economics.

- Many economic drivers play a meaningful role in PV economics. Frequently, a dozen or more individual drivers increase or decrease PV project economics by $.01/kWh or more on a levelized basis. This means that informed PV discussions should weigh many factors when predicting or evaluating deployment.

- The largest economic drivers of PV in New England tend to be: (1) system installed cost (i.e., first cost), (2) physical power revenue (wholesale, offsetting on-site electricity loads, net metering), (3) renewable energy credit (REC) revenue, (4) Federal investment tax credit, and (5) Federal depreciation. Physical power revenues become increasingly important over time, while REC revenues and total Federal support tend to decline over time. The relative order of importance of these five drivers varies by state, customer type, and project start year.

In order to provide clarity, input assumptions are described in this analysis and individual output values are displayed in tables as well as in waterfall charts for all 54 combinations of state, customer type, and project start year.

1.4 Limitations

This analysis includes general assumptions in order to present standardized outputs. However, in practice, PV investment decisions are made one project at a time. Local solar resources, site constraints, equipment choices, incentive eligibility, load profiles, utility rate schedules, financing structures (e.g., debt percentages), REC strategies, and investment objectives will affect the economics of any PV project. PV developers and owners need to, and do, weigh these factors when making individual investment decisions. The aggregation of their behaviors determines the ultimate level of PV deployment. This analysis is not a substitute for individual project analysis, but rather a characterization of major factors at play and how they differ in general across states and customer types and over time. This analysis is also not intended to serve as an assessment of the relative merits of the New England states' PV policies. The manner in which the methods and results of this work will inform ISO-NE's PV forecasts will be developed by ISO-NE in consultation with the Distributed Generation Forecast Working Group as part of ISO-NE's 2015 PV forecast.

2. INTRODUCTION

2.1 Purpose

Solar photovoltaic (PV) project commercialization depends on a complex interplay between public and private investment and business models, which can be deconstructed into economic building blocks or drivers that support PV development. ICF International (ICF) is supporting ISO-New England (ISO-NE) by evaluating the current and potential future drivers of PV economic viability across New England. ICF understands that ISO-NE, the Distributed Generation Forecast Working Group (DGFWG), and other ISO-NE stakeholders frequently deliberate on current and expected future trends in PV growth in the region and the relative importance of various factors in driving that growth. Such deliberations, including those associated with ISO-NE's PV forecasts, will benefit from clear, objective summaries of the main drivers or factors that contribute to PV investment returns.

To serve that purpose and in response to stakeholder feedback that PV economics need to be considered as part of the ISO-NE forecast process, ICF has developed a financial model of PV economics that quantifies 16 economic drivers of PV. ICF applied that model to estimate PV economics, under simplifying assumptions, for residential, commercial, and utility scale PV projects in each New England state. Model results were generated for PV projects that begin operation in three different years (2015, 2019, and 2024)[1] to show how PV economics may differ over time as technology cost and performance, incentive policies, and utility rates change. The outputs of this analysis are (i) levelized per kilowatt-hour (kWh) impacts for each economic driver of PV, and (ii) sub-totals of economic driver impacts. The sub-totals (or summary measures) include levelized cost of energy; unsupported PV economics (crediting only wholesale power revenues to the PV project and not any Federal, state, or utility policies or financing support); federally supported PV economics (before any state or utility policy effects); and fully supported PV economics (including Federal, state, and utility policies and financial engineering).[2]

The assumptions used in this analysis were presented in draft form to the DGFWG in December 2014. Several suggestions for modifications and clarifications in model inputs have been reflected in this report.[3] These assumptions drive model outputs, which are based on the financial model applied for this analysis.

2.2 Organizing Principles

This report is organized into four main parts:

- *Financial Model (including inputs used)*
- *Outputs of Analysis (including data tables and description of alternative scenarios)*
- *Summary of Results*
- *Additional Appendices (including waterfall charts displaying each outcome)*

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[1] These starting dates were selected by ISO-NE to relate to its forecast horizon.
[2] For more detailed descriptions of the sub-total summary measures, please see Section 4.2 of this report.
[3] The manner in which each DGFWG comment was addressed is described in a comment response matrix that is posted on the DGFWG portion of the ISO-NE website (see http://www.iso-ne.com/committees/planning/distributed-generation).

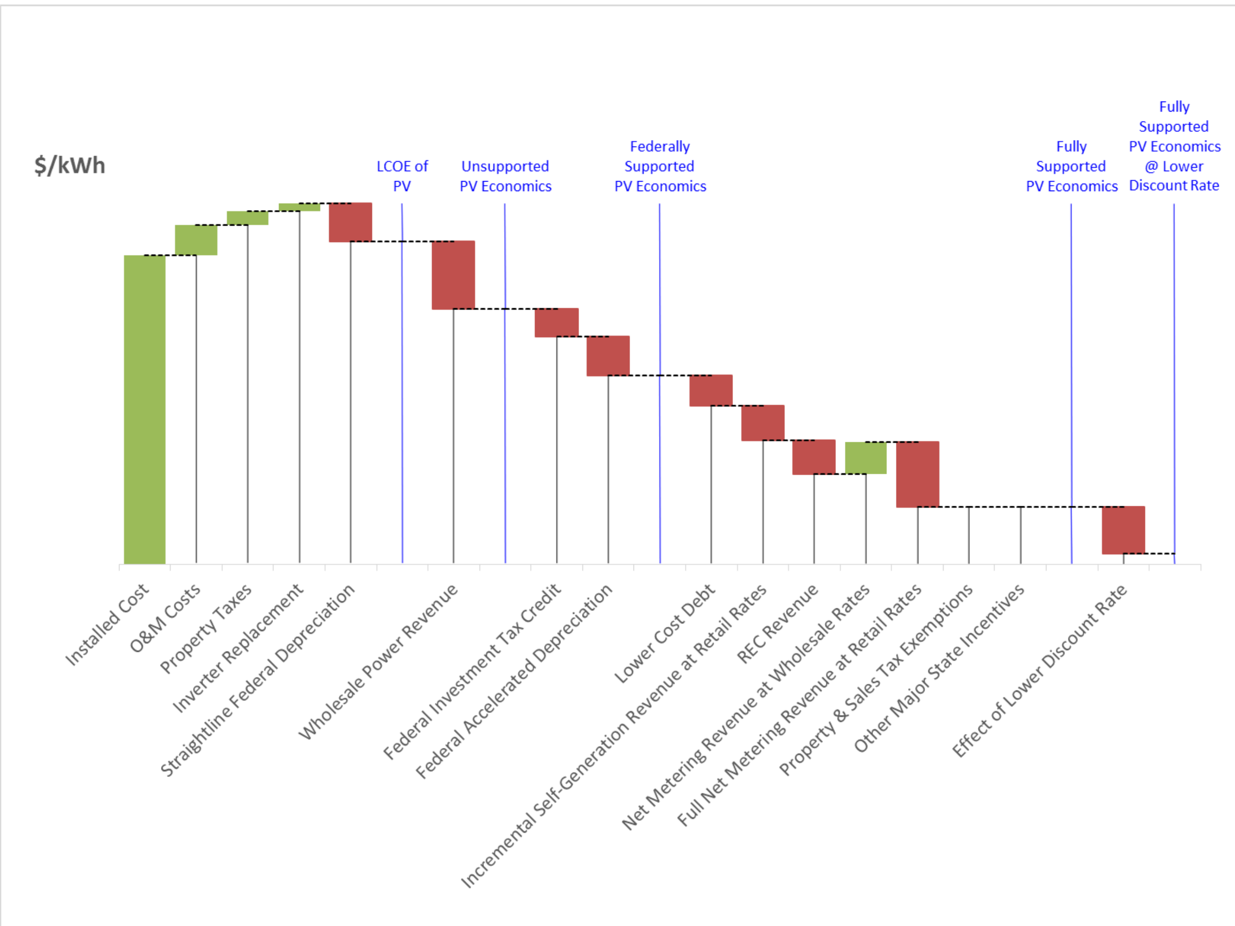
In addition to this narrative report, ICF is providing ISO-NE with a PowerPoint slide deck that follows the same organizing principles. The PowerPoint deck is meant to briefly summarize this report.

3. FINANCIAL MODEL

3.1 Overview

An MS Excel-based financial model was developed to characterize the contributions of individual drivers or factors in PV economics. Having this framework is useful in order to compare PV economics across the 54 combinations of state, customer type, and project start year analyzed.[4] The model contains 23 inputs and has sufficient data on those inputs to create 25-year cash flows for each of 16 economic drivers (a subset of the inputs) for each of 54 combinations mentioned above. An example, generic output chart from this analysis is shown in Exhibit 3-1.

Exhibit 3-1: Generic PV Economic Drivers Output Waterfall Chart



[4] The 54 (= 6 x 3 x 3) combinations are comprised of the six New England states (Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire, and Maine), three customer types (residential, commercial, and utility scale), and three project start years (2015, 2019, and 2024).

The waterfall chart displays the $/kWh contribution to PV economics of each of the 16 drivers and five sub-totaled summary measures under the standardized assumptions of this analysis. The 16 drivers are listed along the x-axis and the five summary measures are in blue in the upper half of the chart. Waterfall charts for each study outcome show $/kWh values that are levelized using a standard discount rate and reflect present dollars for the year of PV installation.

Within the waterfall charts, a green chart slice indicates the normalized value of an added cost (e.g., O&M) in PV economics, and a red slice indicates the normalized value of an added benefit or revenue item (e.g., renewable energy credit (REC) revenue) in PV economics. The waterfall charts can most easily be interpreted by reading them from left to right. First, costs of PV ownership are built up on the left side of the charts and, then, they are decreased by various benefits that are grouped in order to separate the effects of Federal versus non-Federal support and other groupings of factors.

3.2 Limitations of Analysis

This analysis includes general assumptions in order to present standardized outputs. However, in practice, PV investment decisions are made one project at a time. Local solar resources, site constraints, equipment choices, incentive eligibility, customer load profiles, utility rate schedules, financing structures (e.g., tax monetization structures, cost of debt, debt coverage), REC strategies, counterparty risk, and investment objectives will affect the economics of any PV project. PV developers and owners need to, and do, weigh these factors when making individual investment decisions. The aggregation of their behaviors determines the ultimate level of PV deployment. This analysis is not a substitute for individual project analysis, but rather a characterization of major factors at play and how they differ in general across states and customer types and over time.

Further, in order to increase the transparency of this work, publicly-available government sources of PV and electricity market data are frequently used. To increase the uniformity of this work, Federal government data covering multiple states are used in several places. In some cases, useful proprietary, state, local, or utility data exist that differ somewhat from information applied in this analysis, but such specialized data were not used due to the emphasis on transparency and uniformity in this analysis. All analyses are done on an annualized basis, with one set of exceptions.[5] This annualized method was used in order to meet the budget and timeline requirements of the analysis, but is also a limitation. PV financial analyses are most precisely conducted on hourly, or sub-hourly (15-minute), interval bases.

This analysis should not be interpreted as a forecast of future events or outcomes. The analysis does not predict future levels of PV capacity deployment nor electricity output. Rather, the analysis separates PV economics into components so that readers can see what may be more and less important drivers and how those drivers vary by state, customer type, and over time.

While the analysis contains assumptions in several instances on future levels of state incentives where incentive levels have not yet been established, these assumptions are neither predictions

[5] Energy production and consumption volume (kWh) data are computed hourly and then aggregated annually. Specifically, PV production is computed hourly and matched to hourly electricity consumption to calculate self-generation versus net metered volumes..

nor suggestions. The assumptions are only meant to create incentive values for the analysis in line with decline rates for other known incentives in the region over time.

Also, this analysis does not take any position on the distribution and transmission system benefits and costs of PV, the grid and storage integration of renewable energy, nor the environmental, societal, or economic development effects of PV deployment. These additional elements are sometimes included in "Value of Solar" analyses. More broadly, this analysis is not intended to analyze the cost-effectiveness of Federal, state, or utility PV policies, nor to make value judgments about the need for, or appropriateness of, Federal, state, or utility PV policies.

In displaying various measures of PV economics, the report is simply trying to capture the respective economic differences between three situations in which (i) PV output is not distinguished from round-the-clock wholesale grid power ("unsupported PV economics"), (ii) PV projects receive Federal support but zero state or utility policy support ("Federally supported PV economics"), and (iii) PV projects access a typical range of currently-available and projected Federal, state, and utility support and financial structuring benefits ("fully supported PV economics"). The report does not compare the level or efficacy of PV support to that received by other forms of electricity generation. Additional notes about limitations of this analysis are included in portions of this report describing financial model inputs and outputs.

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3.3 Inputs

There are 23 types of inputs into the financial model, which are discussed in turn beginning on the next page. These inputs are listed in Exhibit 3-2. The inputs that are also "economic drivers" have cost or revenue streams (in nominal dollars) of up to 25 years that are discounted using a standard discount rate of 10% to real dollars of the project start year.[6] The application of the discount rate is frequently reiterated within economic driver descriptions below.

[6] The study provides results for an alternative discount rate of 5% as well, as described in subsection 3.3.W below.

Exhibit 3-2: Inputs to PV Economic Drivers Analysis

A. PV System Size (Capacity)	I. Installed Cost*	Q. Project Debt*
B. PV System Configuration	J. Operations and Maintenance (O&M) Cost*	R. Retail Electricity Rates (for self-generation volumes)*
C. PV Electricity Output	K. Property Tax*	S. Net Metering Rates: Wholesale vs. Retail Compensation* (note: this input produces two drivers)
D. On-Site Consumption Offset by PV Electricity Output	L. Inverter Replacement Cost*	T. Renewable Energy Credits (RECs)*
E. Net Metered Volumes	M. Straightline Federal Depreciation*	U. Property and Sales Tax Exemptions*
F. Project Duration	N. Wholesale Electricity Rates*	V. Other Major State Incentives*
G. Salvage Value	O. Federal Investment Tax Credit*	W. Discount Rate*
H. General Inflation Rate	P. Federal Accelerated Depreciation*	

**** = Also is an "economic driver" with discounted cash flows calculated in this analysis***

A. PV System Size (Capacity)

A standard system size (capacity) is applied in this analysis for each customer type. The system sizes are not varied by state or over time. The residential system size used is 5.13 kW_{DC}. For commercial and utility scale systems, the respective system sizes are 100.8 kW_{DC} and 2,000.1 kW_{DC}.[7]

The residential size is consistent with Massachusetts Department of Energy Resources (MassDOER) data for system sizes and is also near the midpoint of the small PV system size range in a recent U.S. Department of Energy report on PV system costs.[8],[9] There is a relatively wide band of commercial system sizes deployed in practice; the 100 kW size used here was chosen because it strikes a balance between being distinguished from residential scale and somewhat close to an average commercial system size. For example, this commercial system size lands squarely within the Market Sector B range for the Massachusetts SREC II program[10] (allowing the analysis to incorporate different solar renewable energy credit factors into the financial analysis), within the "Medium Scale" (26 kW to 250 kW) size category in Rhode

[7] The system sizes are not exactly 5 kW, 100 kW, and 2,000 kW due to the need to calibrate them with solar module sizes (see PV System Configuration sub-section below for more information on exact system sizing).

[8] The median size of residential systems with 2013 and 2014 commercial operation dates was 5.8 kW, as summarized from data as of October 7, 2014, that MassDOER collected on PV systems. For current data, see MassDOER, RPS Solar Carve-Out Qualified Units, http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-carve-out-program.html. The median system sizes for commercial and utility scale systems, as the report authors defined such categories, in the same MassDOER data were 65 kW and 2,500 kW, respectively.

[9] See U.S. Department of Energy (with National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory), *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition*, September 22, 2014, http://www.nrel.gov/docs/fy14osti/62558.pdf.

[10] MassDOER, *Massachusetts Solar Market: RPS Solar Carve-Out II Final Policy Design*, December 13, 2013, page 7, http://www.mass.gov/eea/docs/doer/rps-aps/doer-srec-ii-final-design-restructuring-roundtable-sylvia-121313.pdf.

Island's Renewable Energy Growth Program[11], and at the size cut-off for both the Connecticut small ZREC program[12] and the New Hampshire commercial and industrial rebate program.[13]

The utility scale system size was established within the cap for Class III net metering in Massachusetts and is also generally consistent with MassDOER data for the sizes of such systems. This system size is also near the size cap (2.2 MW) of Vermont's (Sustainably Priced Energy Enterprise Development or SPEED) standard offer program[14] and within the 1-5 MW range for large solar projects in Rhode Island's Renewable Energy Growth Program.

B. PV System Configuration

This analysis utilizes hourly alternating current (AC) output from the PV system in order to differentiate between PV production that is consumed on-site by the PV host and PV production that is net metered or sold directly to the grid.[15] The analysis used three standard PV system configurations; one each for residential, commercial, and utility scale systems. The specific fixed-axis configurations used were:

- Residential: 285 watt Trina panels[16] (18 panels for a 5.13 kW_{DC} system); 5.2 kW Solectria inverter[17]; and 25 degree tilt angle to represent typical flush-to-roof installations.

- Commercial: 300 watt Trina panels (336 panels for a 100.8 kW_{DC} system)[18]; 4 x 20 kW Solectria inverters; and 10 degree tilt angle to represent typical low-slope ballast racking system.

- Utility scale: 300 watt Trina panels (6,667 panels for a 2,000.1 kW_{DC} system)[19]; Solectria string inverters totaling 1.62 MW_{AC}; 25 degree tilt angle for Massachusetts, Connecticut, and Rhode Island; and 30 degree tilt angle for Vermont, New Hampshire, and Maine to represent the trade-off between ideal tilt angles for production and minimizing ground area usage.

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[11] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=RI37F&ee=0.
[12] See, for example, Connecticut Light & Power, Renewable Energy Credits, http://www.cl-p.com/Home/SaveEnergy/GoingGreen/Renewable_Energy_Credits/.
[13] See New Hampshire Public Utilities Commission, http://www.puc.nh.gov/Sustainable%20Energy/RenewableEnergyRebates-CI.html.
[14] See Vermont Public Service Department, http://publicservice.vermont.gov/topics/renewable_energy/standard_offer.
[15] The PV system configurations selected for this analysis did not affect the installed cost nor other cost data; the configurations, using commonly-available equipment and design standards, were made only for the purpose of developing PV hourly production profiles. Capacity factors (annual output levels) from these PV configurations were calibrated on a state-by-state basis to be consistent with capacity factors presently used by ISO-NE in its PV production forecasts. The next sub-section of the report describes the calibrations that were conducted.
[16] Trina panels are a mainstream crystalline-silicon product. Other common crystalline-silicon panels should have comparable performance characteristics for the limited purposes to which panel choices were applied in this study.
[17] Though this is a somewhat large inverter relative to the DC capacity size chosen, it is a reasonable choice given the nearest size inverter from Solectria and offers system flexibility benefits. For the larger commercial and utility scale systems in this analysis, aggregate DC capacity to inverter size is near typical 1.25:1 or 1.2:1 ratios.
[18] This system was assumed to be exactly 100 kW_{DC} for purposes of any PV program or incentives cut-offs in this analysis.
[19] This system was assumed to be exactly 2,000 kW_{DC} for purposes of any PV program or incentives cut-offs in this analysis.

Crystalline-silicon modules are used because they maintain more market share than thin-film modules. Fixed-tilt systems were used rather than tracking systems for the same reason. Inverters from Solectria are used because they are both a mainstream equipment choice and are made by a New England firm.[20] Energy storage (e.g., batteries) is not included in the system configurations.

C. PV Electricity Output

National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM)[21] is used to create hourly net AC production from each type of customer PV system for a typical meteorological year (TMY) at a site in each state.[22] Thereby, 8,760 (24 hours/day x 365 days/year) hourly PV output values were produced for each customer type in each New England state for 2015 and were increased by 1/1,460 to account for leap years. The analysis assumes that the initial energy production of new PV system designs will increase by 5% in total between 2015 and 2019 and another 5% between 2019 and 2024 compared to 2015 levels.[23]

The hourly output from NREL SAM for each system is proportionately reduced to be in line with the annual capacity factors in ISO-NE's *PV Energy Forecast Update* to the DGFWG dated September 15, 2014.[24] While NREL SAM creates generally accurate production data, that production data can be thought to reflect a somewhat idealized PV system; i.e., one that is well-designed on a roof oriented to the south[25] without shading and with proper operations & maintenance (O&M) being conducted. In practice, not all sites are ideal. Shading from trees or other obstructions can exist, the pitch of the roof or its orientation towards the Sun may not be perfect, and system design or O&M occasionally have drawbacks. Further, the NREL SAM data are run for a single site in each state and do not represent the diversity of solar resources within

[20] Overall, the system configuration choices have only a modest effect on this analysis. They determine the hourly production shape of PV output, which then determines how much PV output offsets on-site consumption versus is net metered to the utility. They also affect capacity factors by customer type (which affect physical power and renewable energy credit revenues), but statewide capacity factors in this analysis are calibrated to those used in ISO-NE's PV forecast.

[21] NREL SAM is a publicly available solar modeling program with integrated access to many TMY weather files and the ability to include specific PV configurations.

[22] TMY3 weather files are used from airport sites in Boston, Massachusetts; Hartford, Connecticut; Providence, Rhode Island; Burlington, Vermont; Concord, New Hampshire; and Portland, Maine.

[23] The increase in PV production may come from a combination of sources including PV module efficiency gains, inverter efficiency improvements, enhanced designs to minimize system losses, and improved O&M practices.

[24] The DC based capacity factors in that ISO-NE report were: 13.1% for Massachusetts, 13.7% for Connecticut, 13.2% for Rhode Island, 12.0% for Vermont, 12.8% for New Hampshire, and 13.0% for Maine. The hourly PV production outputs in this analysis were calibrated so that they would arrive at the same statewide average capacity factors as ISO-NE uses, with statewide average being defined here as the simple average of residential, commercial, and utility scale capacity factors. Specifically, NREL SAM outputs were adjusted downward by 19.5% for Vermont, 18.7% for Maine, 17.8% for New Hampshire, 16.5% for Rhode Island, 16.4% for Massachusetts, and 7% for Connecticut. The capacity factors calculated from NREL SAM are higher for utility scale systems than for residential systems and higher for residential systems than for commercial systems. These calculations reflect system configurations entered into NREL SAM, including the lower tilt angle of commercial systems due to flat roofs that depress capacity factors, other factors equal.

[25] South orientation, if a viable design option, typically maximizes annual PV electricity production. In New England, most PV system revenues (i.e., from physical power production and renewable energy credits) are tied to total production, which leads to an emphasis on south-facing systems in practice and in this analysis. However, systems facing southwest or westerly may produce less annual electricity but have a daily peak production that occurs later in the afternoon and coincides more closely with utility and transmission grid system peak demand.

a state. ISO-NE's capacity factors are an approximation of blended PV output from operating PV systems in New England.

The difference between NREL SAM capacity factors and the capacity factors in ISO-NE's *PV Energy Forecast Update* dated September 15, 2014, might be attributed to many issues, including different equipment selection and vintage, different system design, user maintenance practices, local solar insolation variation, and normal weather variation versus typical meteorological years.

Consistent with industry practice, system output is assumed to degrade at 0.5% per year for projects starting in 2015, 2019, and 2024. All electricity volumes of the 25-year project life are levelized using the same discount rate as is applied to nominal revenues and costs over the same 25 years to arrive at $/kWh values that reflect present dollars for the year of PV installation

D. On-Site Consumption Offset by PV Electricity Output

Hourly residential and commercial[26] consumption profiles for a typical year are applied in this analysis in order to separate self-generation volumes from net metered volumes. The calculation of net metered volumes is described in the next sub-section of this report.

The consumption profile for commercial customers is based on historic customer class-wide data from the utility National Grid (Massachusetts).[27] For residential customers, the "residential customers without electric heat" consumption profile from Central Hudson Gas & Electric is used.[28] Though this utility is in the Hudson Valley of New York, and not within New England, its weather patterns should be similar to those of New England. Using customer class-wide profiles is preferable to individual customer profiles because class-wide data are representative of the variation among customers.

The above methods are used to obtain the consumption <u>shape</u> (from hour-to-hour). The <u>level</u> of residential and commercial consumption in this analysis was established so that PV production offsets 100% of annual on-site consumption in year 1 of PV system operation. This sizing implies that PV systems' peak output will be approximately three to four times customer peak demand. Electricity consumption is assumed to remain constant throughout the 25-year PV project duration.

On-site electricity consumption of utility scale systems is assumed to be zero (but the analysis separately values net metering volumes from such projects to the extent virtual net metering is permitted).

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[26] This analysis assumes that utility scale projects do not have on-site load, but utilize virtual net metering (also called group net metering) to the extent that state project net metering capacity caps and regulations allow.

[27] The commercial data were from a file with 2004 data produced by the utility that was a simplified rate class load shape for G2 tariff (commercial and industrial (C&I) demand metered, under 200 kW) customers in National Grid (Massachusetts Electric) territory. Though this is an older data set, the study authors believe it is appropriate for the limited purpose for which it is used. Overall load shape across this entire customer class is not expected to have changed dramatically in intervening years, except for typical year-to-year weather variations.

[28] This consumption profile contains hourly loads for a weekday and a weekend each month. See http://inet.cenhud.com/ic_esco/general_information/loadpf.htm. For this analysis, the utility data were extrapolated to obtain hourly consumption profiles for each hour of the year through reference to the hourly commercial consumption profile from National Grid (Massachusetts Electric).

E. Net Metered Volumes

Net metered volumes, as defined in this analysis, are obtained by deducting PV production in every hour from on-site consumption during that hour and summing the positive differences annually. This calculation is performed using residential PV production versus residential electricity consumption, commercial PV production versus commercial electricity consumption, and utility scale PV production (to the extent of project-level net metering limits per state) versus zero on-site electricity consumption.[29],[30],[31],[32]

Calculating net metered volumes on an hourly basis accounts for the differing cycles of PV production versus customer electricity consumption on a more precise basis[33] than simply forming annual net metering assumptions. This hourly approach also highlights how net metering changes in the future may have a larger relative effect on the economics of projects that frequently produce more PV electricity than is used contemporaneously on-site.

In this analysis, net metering is applied to residential and commercial customer types in all six New England States.

At the project level, the Class III net metering cap in Massachusetts is 2,000 kW, the virtual net metering cap in Connecticut is 3,000 kW (and the general net metering cap is 2,000 kW), and the net metering cap in Rhode Island is 5,000 kW. The study assumes full net metering is applied to the 2,000 kW utility scale projects in those three states. Vermont (except for military and certain other defined classes of projects), Maine, and New Hampshire have project-specific net metering caps of 500, 660, and 1,000 kW, respectively.[34] This analysis assumes that utility scale projects in Vermont[35], Maine, and New Hampshire access net metering to the extent of its

[29] Because many large New England PV projects rely on virtual net metering with extremely small on-site loads compared to PV production levels, their on-site production is taken as zero.

[30] For distributed residential and commercial PV, the sum of (i) self-generation volumes (those that offset on-site consumption) and (ii) net metered volumes equal (iii) total PV production volumes in this analysis. For utility scale systems, no on-site consumption is assumed. Any utility scale production volumes that cannot be virtually net metered nor obtain long-term payments from state solar programs (as Vermont SPEED standard offer and Rhode Island Renewable Energy Growth participants do) will simply remain volumes receiving wholesale power prices.

[31] All PV production volumes are labeled as net metered (not self-generation) for customers participating in the net metering solar credit program in Vermont per a suggestion from a Vermont stakeholder at the December 15, 2014, DGFWG meeting.

[32] If a state restricts virtual net metering to a certain customers (e.g., government agencies), then this analysis assumes that such customers are the hosts of the utility scale projects.

[33] Ideally, net metering and other PV analyses would operate on whatever billing interval is used by the utility (e.g., 15-minute or 30-minute), but hourly analyses are more useful than monthly or annual analyses.

[34] The project net metering caps in Vermont and New Hampshire appear to be driven by AC system capacity for PV projects based upon review of state net metering regulations. The capacity type (AC or DC) for PV projects in Maine could not be fully-established, but is assumed to be based upon AC capacity. For all three states, a standard DC to AC derate factor of 83% was applied to estimate the net metering caps in DC. That resulted in DC net metering caps of 602 kW_{DC} (Vermont), 795 kW_{DC} (Maine), and 1,204 kW_{DC} (New Hampshire).

[35] This analysis assumes that Vermont utility scale 2015 and 2019 project starts participate in the SPEED standard offer program and labels the volumes from that program as "net metering," though that labeling does not affect economic results. Vermont utility scale systems with 2024 project starts are assumed to virtually net meter output from 500 kW_{AC} (602 kW_{DC} with a DC to AC 83% derate) of their capacity and sell output from the remaining 1,398 kW_{DC} of capacity at wholesale rates.

availability in each state, and that utility scale projects will simply sell their PV output in excess of net metering limits at wholesale rates.[36]

This analysis assumes that existing state net metering programs will remain intact, and that existing aggregate net metering program caps (i.e., total net metered capacity allowed by state or utility) will not directly affect or become constraints upon PV economics. This is a significant assumption, as project economics modeled in this study extend through 2048. Several states have been involved in an ongoing process to determine if and how net metering policies, or the aggregate caps themselves, may change as PV and other distributed generation systems approach aggregate caps. Future scenarios in which the above assumptions are no longer true – e.g., caps become constraints, or state net metering programs change and reduce potential revenues via this economic driver – would be likely to yield diminished PV economics.

F. Project Duration

All PV systems in this analysis are assumed to have a 25-year duration.[37] This duration matches the warranties of many PV modules[38] and tends to be at the long end of power purchase agreement (PPA) lengths, which often are 15 years to 25 years. While PV systems can physically operate for longer than 25 years, a number of factors may work against much longer investment durations than 25 years being the norm. These factors include shorter PPA and other contractual durations, roof replacement cycles, changes in ground uses, changes in ownership of sites, equipment warranty expiration, ongoing performance degradation, or equipment replacement. In some PV financial analyses, 20 years is used as the duration. Longer project durations, other factors equal, will produce higher PV investment returns due to the low annual operating costs of PV systems in relation to their annual revenue potential from producing physical power and renewable energy credits.

G. Salvage Value

This analysis assumes zero salvage value at the end of the PV system project life (i.e., after 25 years).

In practice, salvage values could be positive, negative, or near zero. They would be positive if components' total resale value exceeds decommissioning, disposal, surety bond, and site reconditioning costs. There are little comprehensive domestic data on PV system salvage values because most PV systems built in the U.S. are still in operation. Given the relatively long system life ascribed to PV in this analysis, uncertainties in estimating salvage values, the effects of taxation (a positive salvage value could generate a capital gain), and the overall purposes of this analysis, the assumption of zero salvage value is applied here.

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[36] For more information on PV net metering policies by state, see Database of State Incentives for Renewables & Efficiency (DSIRE)™, http://www.dsireusa.org/.

[37] This duration was also used in an evaluation of PV economics recently conducted by Sustainable Energy Advantage, LLC. See *Rhode Island Renewable Energy Growth Program: 2nd Revision to Proposed 2015 Ceiling Price Recommendations*, December 9, 2014, page 49, http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf.

[38] See, for example, Trina Solar, http://www.trinasolar.com/us/about-us/Quality.html, and Suniva, http://www.suniva.com/quality-matters.php.

H. General Inflation Rate

A general price inflation rate of 1.83% is applied to escalate prices that are expressed in real dollars into nominal dollars where appropriate. Specifically, this inflation rate is applied to installed costs and operations & maintenance costs.[39] This inflation rate applied to PV costs is based upon the Federal Reserve Bank of Cleveland's estimates of 10-year inflation expectations[40] and is also consistent with the inflation rate included in the U.S. Department of Energy's (DOE's) wholesale and retail electricity price forecasts[41] that are used in this study. This makes the inflation assumptions used in the study for PV cost drivers and revenue drivers generally consistent.[42]

I. Installed Cost

The installed cost of PV projects includes all capital, labor, and other costs involved in original deployment of the system. Initial values were obtained from a recent publication of the DOE SunShot Program[43] and other sources as described below.

For residential systems, a 2014 value of $4.29/watt$_{DC}$ (or $4,290/kW$_{DC}$), as suggested by a Vermont stakeholder based on recent experience in that state, is used. That value is between the values in the SunShot report reported for Connecticut ($4.03/watt$_{DC}$ or $4,030/kW$_{DC}$) and Massachusetts ($4.45/watt$_{DC}$ or $4,450/kW$_{DC}$) for residential-sized systems.[44],[45] For commercial systems, the SunShot report does not include Connecticut values, but identifies an average Massachusetts value of $3.40/watt$_{DC}$ (or $3,400/kW$_{DC}$) that is used in this analysis to represent

[39] Both installed system costs and O&M costs are comprised of a variety of goods and services, including both capital and labor. For example, installed costs include silicon (for solar cells); glass and metal used in modules; inverters; racking; conduit; ballast in some cases; freight; professional services labor from engineers, attorneys, financiers, and managers; installation labor; and permits). The range of costs involved is a reason for using a market basket inflation measure like this index.

[40] The Federal Reserve Bank of Cleveland publishes its estimates of 10-year inflation expectations each month. The November 2014 release value was 1.83% The value can change each month. For example, the value was 1.89% in the September 2014 release, 1.87% in October 2014, 1.78% in December 2014, and 1.66% in January 2015. See, for example, https://www.clevelandfed.org/en/Our%20Research/Indicators%20and%20Data/Estimates%20of%20Inflation%20Expectations.aspx.

[41] For the DOE wholesale and retail electricity price forecast series from the *Annual Energy Outlook* covering the period, the average gap between nominal and real prices was approximately 1.8%. See http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

[42] The inflation rates in the Federal Reserve Bank of Cleveland and DOE data are low, but not unprecedented, by historic standards. For comparison, the approximate average increase in the U.S. Consumer Price Index for all items for Northeast Urban consumers each year over the period 2004 to 2013 was approximately 2.5%. Annual inflation rates going back to 1913 average above 3% nationally. See Bureau of Labor Statistics, U.S. Department of Labor, http://www.bls.gov/cpi/data.htm.

[43] See U.S. Department of Energy (with National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory), *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition*, September 22, 2014, http://www.nrel.gov/docs/fy14osti/62558.pdf.

[44] Though detailed PV system cost data are in the Massachusetts Department of Energy Resources' (MassDOER's) RPS Solar Carve-Out Qualified Units files, for this analysis the vetted and published data from the SunShot program are preferred to the MassDOER raw cost data.

[45] For recent installed cost data on somewhat larger residential systems than used as the benchmark in this study, see also Connecticut Clean Energy Finance and Investment Authority, *Market Watch Report, Residential Solar Investment Program*, Program Data as of January 16, 2015.

all New England systems.[46] Those 2014 residential and commercial installed costs are (i) reduced by the annual real decline rate forecasted for PV installed costs in DOE's *Annual Energy Outlook*, and (ii) increased by the annual price inflation rate (described above) to obtain 2015, 2019, and 2024 nominal dollar installed costs for this analysis.

The same SunShot report has a wide range of values for utility scale costs. To place appropriate utility scale costs within that range, this analysis uses a $2.15/watt$_{DC}$ (or $2,150/kW$_{DC}$) cost for 2014 based upon a recent PV economic review issued in New England[47] and uses the same combination of *Annual Energy Outlook* real decline rates[48] and price inflation rates as for residential and commercial systems. The installed costs (in nominal dollars) used in the analysis for each customer type for each project start year are summarized in Exhibit 3-3. The Exhibit also displays the same data in real (constant) 2014 dollars.

Exhibit 3-3: Assumed PV Installed Costs

Customer Type	Currency	2015 Project Starts[49]	2019 Project Starts	2024 Project Starts
Residential	Real 2014 dollars	$4,010/kW$_{DC}$	$3,660/kW$_{DC}$	$3,440/kW$_{DC}$
	Nominal dollars	$4,080/kW$_{DC}$	$4,010/kW$_{DC}$	$4,120/kW$_{DC}$
Commercial	Real 2014 dollars	$3,170/kW$_{DC}$	$2,900/kW$_{DC}$	$2,730/kW$_{DC}$
	Nominal dollars	$3,230/kW$_{DC}$	$3,180/kW$_{DC}$	$3,270/kW$_{DC}$
Utility Scale	Real 2014 dollars	$2,010/kW$_{DC}$	$1,840/kW$_{DC}$	$1,720/kW$_{DC}$
	Nominal dollars	$2,040/kW$_{DC}$	$2,010/kW$_{DC}$	$2,070/kW$_{DC}$

Installed costs are expressed above in relation to the rated direct current (DC) capacity of system modules. Because there is a standard associated with the DC rating of PV panels that is independent of system design, DC capacity is commonly used to define PV project size and unit cost. Converting installed costs to alternating current (AC) capacity requires a review of system AC capacity.

It is assumed that these installed costs do not include sales taxes (due to the prevalence of sales tax exemptions). The average sales tax in each state[50] is added to half of the installed costs (under the assumption that half of PV costs are comprised of taxable equipment). Sales

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[46] These residential and commercial installed costs are similar to the figures ($4,281/kW$_{DC}$ and $3,305/kW$_{DC}$, respectively) used in a recent Rhode Island PV evaluation. See Sustainable Energy Advantage, LLC, *Rhode Island Renewable Energy Growth Program: 2nd Revision to Proposed 2015 Ceiling Price Recommendations*, December 9, 2014, page 44, http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf.

[47] See Sustainable Energy Advantage, LLC, *Rhode Island Renewable Energy Growth Program: 2nd Revision to Proposed 2015 Ceiling Price Recommendations*, December 9, 2014, page 44, http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf. This system was appropriate for 1-5 MW projects in the Sustainable Energy Advantage report. The Sustainable Energy Advantage document contains a $2.151/watt$_{DC}$ price, which is rounded to $2.15/watt$_{DC}$ for this study to be consistent with the rounding used for residential and commercial installed costs.

[48] For a brief discussion of other public forecasts of decline rates for PV installed costs, see Appendix F of this report.

[49] 2015 project start installed costs differ from the 2014 costs listed in the text above because the *Annual Energy Outlook* price decline forecast between 2014 and 2015 exceeds the rate of price inflation between those years. Conversely, though the *Annual Energy Outlook* forecasts a decline in real (constant dollar) installed costs each year between 2016 and 2024, the cumulative rate of inflation during that period exceeds the real cost reductions. This leads to nominal installed costs being estimated as higher in 2019 than in 2015 and higher in 2024 than in 2019.

[50] See Federation of Tax Administrators, *State Sales Tax Rates and Food & Drug Exemptions*, http://www.taxadmin.org/fta/rate/sales.pdf.

tax is added at this stage to allow for display of the incentive value of tax exemptions later in the analysis.

The installed cost per watt is multiplied by the PV system size for each customer class to arrive at the driver called "installed cost."

J. Operations and Maintenance (O&M) Cost

This analysis begins with 2015 annual O&M values of $32.80/kW$_{DC}$ for residential PV systems, $23.50/kW$_{DC}$ for commercial systems, and $20.49/kW$_{DC}$ (converted from $24.69/kW$_{AC}$ using a 83% DC-to-AC derate) for utility-scale systems.[51],[52] These O&M costs are inflated annually with the study's assumed inflation rate.

The O&M value each year is multiplied by the original system size (capacity) to arrive at the economic driver called "O&M costs." The 25-year O&M cost stream is discounted at the standard rate of 10% applied throughout this analysis.

Inverter replacement costs are not included here, but are their own line item in the financial analysis.

K. Property Tax

The driver called "property taxes" is calculated by multiplying original installed PV costs by 0.5% each year.[53] Property tax is included as a recurring cost to demonstrate the value of property tax exemptions (that are prevalent for PV) later in the analysis. In practice, property tax rates vary widely from county to county. The value used here is a very rough proxy.

L. Inverter Replacement Cost

The analysis assumes that inverters will be replaced in year 15 of the project at 8% of the original installed cost of the project, and the driver "inverter replacement" is calculated accordingly.[54] A useful inverter life of 15 years is a standard PV industry assumption[55] that is

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[51] The utility-scale O&M starting value was obtained from Energy Information Administration, U.S. Department of Energy (DOE), *Annual Energy Outlook (AEO) 2014* (http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf) and was expressed in AC capacity, thereby requiring a conversion to DC capacity to be used in this study's calculations. The residential and commercial O&M starting values were obtained from the DOE, *SunShot Vision Study*, http://energy.gov/downloads/sunshot-vision-study. Additional information on PV O&M costs produced by the National Renewable Energy Laboratory can be found at: http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.

[52] For another view of PV O&M costs, please see Sustainable Energy Advantage, LLC, *Rhode Island Renewable Energy Growth Program: 2nd Revision to Proposed 2015 Ceiling Price Recommendations*, December 9, 2014, page 47, http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf. That report divides O&M expenses into multiple sub-categories.

[53] In addition, Vermont's $4/kW capacity tax is included in this driver. Because systems at or below 10 kW are exempt from this tax, residential customer types are credited with an exemption of this amount subsequently in the property and sales tax exemption portion of this analysis. See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT53F&ee=1.

[54] Inverter replacement is an occasionally overlooked aspect of PV economics. Inverters, which convert DC power from the panels into AC power that can be used by the project host or utility, are relatively complex pieces of equipment, and it is prudent to plan for their replacement so that unexpected expenses do not occur.

[55] Inverter manufacturers frequently offer combined basic and extended warranties extending from 10 to 20 years in total duration. For example, many of Solectria's combined basic/extended warranty packages are for 20 years. See

consistent with some inverter warranty durations, and inverters can comprise 6% to 10% of a PV project's cost. The assumption that replacements will be 8% of the original system cost implies that inverters may decline in real costs.

M. Straightline Federal Depreciation

To demonstrate a depreciation treatment before PV incentives, the (pre-sales tax)[56] installed cost of the PV systems is assumed to be depreciated on a straightline basis (equal amounts depreciated each year of the 20-year project life).[57] To arrive at the driver called "straightline Federal depreciation," annual depreciation amounts (5% x installed cost for each of the first 20 project years) are multiplied by a 35% marginal Federal tax rate.[58] The resulting annual totals are discounted using the standard rate of 10% applied throughout this analysis.

In a subsequent portion of the analysis, the marginal value of Federal accelerated depreciation (above straightline depreciation) is calculated and displayed as its own economic driver.

N. Wholesale Electricity Rates

This analysis uses the New England generation price series ("Electric Power Projections by Electricity Market Module Region, Northeast Power Coordinating Council / New England, Reference Case") from the Energy Information Administration, DOE, *Annual Energy Outlook (AEO) 2014*.[59]
Specifically, the analysis uses the *AEO* generation price to represent wholesale electricity prices. This *AEO* generation price series for New England includes a mix of two methods. For 97% of the series that is assumed to correspond to competitive markets, the sub-components are physical energy (calculated at margin cost), taxes, and a capacity payment that also covers costs associated with meeting spinning reserves. An average costing method is used for the other 3% of the pricing that the *AEO* attributes to fully regulated supply in New England.[60]

These annual prices are applied in this analysis through the *AEO* forecast horizon of 2040. To arrive at prices between 2041 and 2048, the average rate of change between 2015 and 2040 *AEO* prices is extended forward. The annual wholesale prices used are displayed in Exhibit 3-4.

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http://solectria.com/support/documentation/warranty-information/grid-tied-inverter-warranty-letter/. 15 years is a reasonable assumption and implies that the inverter will be replaced once during the overall PV system life of 25 years.

[56] Due to the prevalence of PV sales tax exemptions in New England, it is prudent not to include sales tax in the depreciation calculations because few buyers should incur it. Sales tax is included in "installed cost" earlier in this analysis so that the value of sales tax exemptions can be displayed at a later stage.

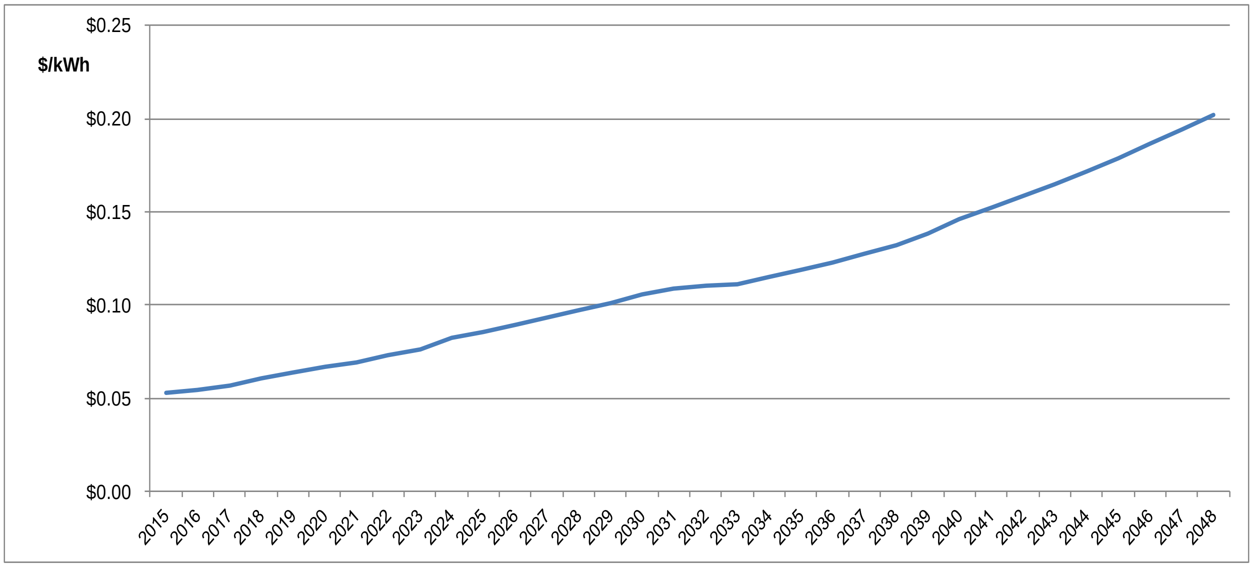
[57] PV systems are considered 20-year assets for tax purposes.

[58] Only if the PV system is owned by a for-profit business (the project host itself or a third-party owner such as a solar developer) are depreciation benefits available.

[59] See http://www.eia.gov/forecasts/aeo/tables_ref.cfm. *AEO* is a publicly-available source that uses a multi-dimensional (National Energy Modeling System) method to arrive at its price forecasts, and these data can be readily updated in the future with new editions of *AEO*.

[60] See DOE, *Electricity Market Module*, page 102 (PDF page 10), http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.

Exhibit 3-4: New England Wholesale Electricity Prices based on U.S. Department of Energy Forecast (in nominal dollars)



These annual wholesale electricity prices are multiplied by annual PV output to calculate the driver "wholesale power revenue" in this analysis. The resulting 25-year cash flows are discounted at the standard rate of 10% applied throughout this analysis.[61],[62]

O. Federal Investment Tax Credit

This analysis assumes that the PV project monetizes a Federal investment tax credit (ITC) equal to 30% of total installed costs for projects starting in 2015. For projects starting in 2019 and 2024, a 10% ITC is applied because the ITC is slated to decline to 10% from its current level of 30% on January 1, 2017.[63],[64] The driver "Federal Investment Tax Credit" is calculated by multiplying 30% (for 2015 project starts) or 10% (for 2019 and 2024 project starts) by the (pre-sales tax)[65] installed cost and taking the ITC at project outset in the 25-year cash flow analysis.

[61] This analysis does not estimate revenues for PV systems from capacity, ancillary services, resiliency, or other potential benefits they may offer to the grid nor does it deduct expenses for potential costs of PV systems to the grid. This is because the analysis concentrates on revenue and cost categories that are frequently monetized at this time. In the case of capacity payments, that is an available revenue source, but a relatively small percentage of PV systems within this analysis' system size range (5 to 2,000 kW_{DC}) currently participate in the ISO-NE capacity market. Future capacity price levels are also difficult to forecast.

[62] This analysis operates on annual electricity prices and does not reflect time-of-use (e.g., peak and off-peak) and seasonally-differentiated prices, nor energy storage, loss, and dispatch of electricity.

[63] See Internal Revenue Code, http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA-partIV-subpartE-sec48.pdf.

[64] The ITC declines to 0% in 2017 for residentially-owned systems, but this analysis applies the 10% ITC to the 2019 and 2024 project start years for residential systems because commercial ownership of residential systems occurs within the PPA structure.

[65] Due to the prevalence of PV sales tax exemptions in New England, it is prudent not to include sales tax in the ITC because few buyers should incur it. Sales tax is included in "installed cost" earlier in this analysis so that the value of sales tax exemptions can be displayed at a later stage.

These assumptions are consistent with the facts that (i) third-party financing, including project ownership with sufficient tax liability and sophistication to efficiently monetize tax benefits, is the dominant financing method for distributed residential and commercial PV in high-growth PV markets, and (ii) utility scale PV developers also typically monetize tax benefits efficiently. Additional information on PV financial products is provided for reference in Appendix G.

Some PV system purchasers do not receive the ITC because they do not have sufficient tax liability and/or they do not have the expertise to claim the ITC in their tax accounting. For example, a non-profit agency could purchase a PV system outright (i.e., not finance it through a PPA or lease with a private owner). Such a purchase would not be eligible for the ITC. In that case, one would treat the driver "Federal Investment Tax Credit" as if it was not available.

P. Federal Accelerated Depreciation

The modified accelerated cost-recovery system (MACRS) federal depreciation of 85% of (pre-sales tax)[66] installed costs is applied to projects beginning in 2015. MACRS is applied to 95% of installed costs for projects beginning in 2019 and 2024. The reason for the difference is that the capital basis for MACRS is reduced by half of the ITC, and the ITC declines from 30% to 10% beginning in 2017.[67]

The analysis assumes that accelerated depreciation is efficiently monetized by the PV project owner (i.e., benefits are used in the first possible project years and not carried forward) using a relatively common application of MACRS depreciation called the 200% declining balance with half-year convention MACRS schedule. That schedule's relative depreciation percentages each year for the first six years, from year 1 to year 6, are 20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%.[68],[69] Annual depreciation amounts for each of these first six project years are multiplied by a 35% marginal Federal tax rate to calculate the value of depreciation. To demonstrate the relative effect, the driver "Federal accelerated depreciation" is calculated as the annual difference between MACRS depreciation and straightline depreciation each year and is discounted at the standard rate of 10% applied throughout this analysis.

As with the ITC, this assumption for accelerated depreciation is consistent with the facts that (i) third-party financing, including project ownership with sufficient tax liability and sophistication to efficiently monetize tax benefits, is the dominant financing method for distributed residential and commercial PV in high-growth PV markets, and (ii) utility scale PV developers also typically monetize tax benefits efficiently. No state-level depreciation is included in this analysis, due to the difficulty in obtaining cost-effective Federal tax equity investors that also have sufficient in-state tax liability to monetize state depreciation.

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[66] Due to the prevalence of PV sales tax exemptions in New England, it is prudent not to include sales tax in the depreciation calculations because few buyers should incur it. Sales tax is included in "installed cost" earlier in this analysis so that the value of sales tax exemptions can be displayed at a later stage.

[67] Specifically, the 30% ITC in 2015 reduces the accelerated depreciation basis by 15% (half of 30%). The 10% ITC in 2019 and 2024 reduces the accelerated depreciation basis by 5% (half of 10%).

[68] Depreciation over six years, instead of five years, is due to systems becoming operational intra-year (not on January 1).

[69] See the 5-year column of Table A-1, U.S. Internal Revenue Service, Publication 946, http://www.irs.gov/publications/p946/ar02.html#en_US_2013_publink1000270861.

Some PV system purchasers do not receive accelerated depreciation benefits because they do not have sufficient tax liability and/or they do not have the expertise to claim accelerated depreciation in their tax accounting. For example, a non-profit agency could purchase a PV system outright (i.e., not finance it through a PPA or lease with a private owner). Such a purchase would not be eligible for depreciation benefits. In that case, one would treat the driver "Federal accelerated depreciation" as if it was not available.

Q. Project Debt

In order to demonstrate the beneficial financial effects of introducing debt into PV ownership structures if the debt interest rate is below the owner's discount rate, "lower-cost debt" is one of the drivers evaluated. Specifically, a fixed-rate loan at 5% over 15 years that covers half of the project's installed cost is included in the financial model. These parameters are relatively typical in PV financing.[70] The 5% interest rate might be obtained by a project owner with financial sophistication, scale, and an attractive credit profile. An owner lacking these attributes, or that did not want to incur debt, would not receive the financial benefits of "lower-cost debt" and would ignore this factor when reviewing this report's financial analysis. If interest rates climb in the U.S., the availability of lower-cost debt for PV projects may decline.

The driver "lower cost debt" is calculated as the discounted cash flow of a 15-year, 5% rate loan with annual debt service payments and with the original principal being 50% (assumed debt/equity ratio) of (pre sales-tax)[71] installed cost.[72]

R. Retail Electricity Rates (for Self-Generation Volumes)

Retail electricity rates establish the compensation that PV project hosts receive for what is labeled as "self-generation" volumes in this analysis; i.e., PV output that displaces on-site electricity consumption on an hourly interval basis.[73] Residential and commercial retail electricity prices for each state are assumed at their respective means between the August 2014 YTD and

[70] For example, the 50% debt and 50% equity structure applied is somewhat of a mid-point between projects with no debt or low debt percentages of 20% and those with high degrees of leverage (e.g., 80% debt). This debt/equity ratio is also generally consistent with another recent New England PV economic evaluation. See Sustainable Energy Advantage, LLC, *Rhode Island Renewable Energy Growth Program: 2nd Revision to Proposed 2015 Ceiling Price Recommendations*, December 9, 2014, page 48, http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf.

[71] Due to the prevalence of PV sales tax exemptions in New England, it is prudent not to include sales tax in the loan calculations because few buyers should incur the tax. Sales tax is included in "installed cost" earlier in this analysis so that the value of sales tax exemptions can be displayed at a later stage.

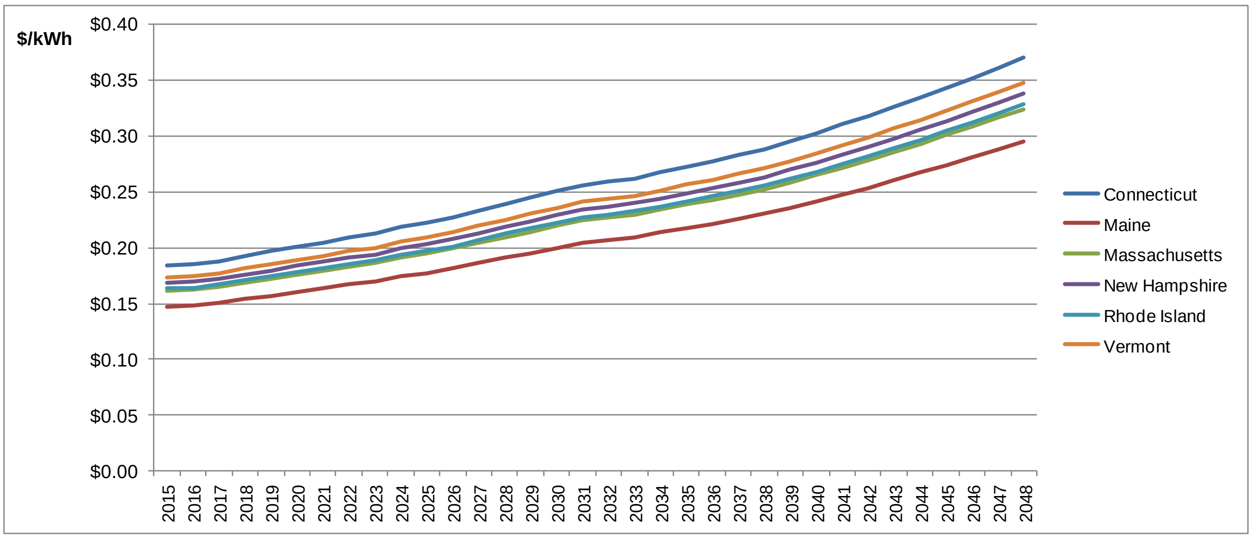
[72] For reference, the study authors also calculated this driver under three other project debt assumptions, all conducted at the 10% discount rate. If project debt was 80%, instead of the standard study assumption of 50%, the value (to the PV owner) of this driver tends to increase (or improve) by about $.02/kWh on average (with a range of effects from $.01 to $.03/kWh depending on the state and customer type). If, on the other hand, project debt is reduced to 20%, the value of the driver decreases by approximately those same amounts. If the length of the loan (with a 50% debt/equity percentage) is reduced from 15 years to 10 years, the value of this driver decreases by about $.01/kWh.

[73] For example, if a residential PV system produces 4 kWh during an hourly interval, and the residential customer consumes 6 kWh during that interval, the entire 4 kWh is labeled "self-generation" in this analysis. In that example, the utility would bill the customer for the 2 kWh of net electricity that it consumed during the hour. On the other hand, if the same customer only consumed 3 kWh (and produced 4 kWh of PV power) during that interval, then the utility would bill the customer for zero kWh for that interval and the 1 kWh of excess PV production would be net metered (see net metering description below).

August 2013 YTD prices published by DOE's Energy Information Administration.[74] Utility scale projects are assumed to have no self-generation volumes, only net metered volumes where applicable.

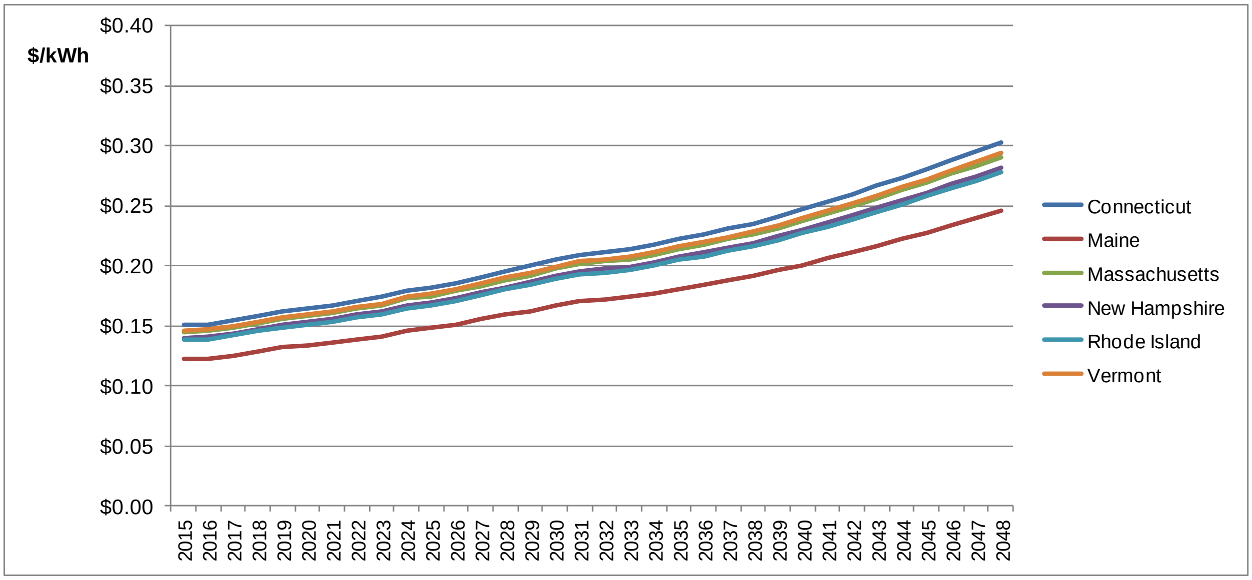
Retail electricity prices from 2016 through 2040 are obtained by applying the annual rate of increase for residential and commercial retail electricity prices in New England from DOE's *Annual Energy Outlook (AEO) 2014* to the 2015 values described above. To arrive at prices between 2041 and 2048 (beyond the *AEO* forecast horizon of 2040), the average rate of change between 2015 and 2040 *AEO* prices is extended forward. The annual retail residential and commercial electricity prices used are displayed in Exhibits 3-5 and 3-6, respectively.

Exhibit 3-5: State-by-State Residential Retail Electricity Prices based on U.S. Department of Energy-reported Historical Data and Forecast Growth Rates (in nominal dollars)



[74] See Energy Information Administration, DOE, *Table 5.6.B., Average Retail Price of Electricity to Ultimate Customers, by End-Use Sector*, drawn from Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report, http://www.eia.gov/electricity/monthly/. The mean of 2013 and 2014 prices was used to modulate the effect of 2014 polar vortex events on these data. While certain utilities have published their tariff electricity rates for at least a portion of 2015 that may diverge from those of 2013 and 2014, historic prices are used in this analysis because they reflect realized, statewide, full-year pricing across the relevant customer classes as reported by DOE.

Exhibit 3-6: State-by-State Commercial Retail Electricity Prices based on U.S. Department of Energy-reported Historical Data and Forecast Growth Rates (in nominal dollars)[75]



In practice, PV production does not equally offset all electricity utility charges. PV output does not change fixed monthly customer charges that are common on both residential and commercial utility bills. Nor does PV production typically offset peak demand charges in full.[76] The reason that peak demand is not fully offset is that relatively high levels of demand usually occur at least once per month during 15-minute or 30-minute billing demand intervals when PV systems are not producing electricity equal to the rated AC capacity of their inverters (e.g., during cloudy or evening periods).

To reflect this peak demand effect, the commercial (but not residential) retail prices for self-generation in this analysis are reduced by $.01/kWh[77] in 2015, and that price difference carries through to future years based upon the same 2016-2048 price logic described above. The value of $.01/kWh is a relatively conservative estimate (or proxy value) of the peak demand effect. Retail prices for self-generation are not adjusted for fixed customer charges, power factor charges, nor time-of-use energy rates.

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[75] The prices in this graph do not include the peak demand offset adjustment described later in this sub-section.

[76] Peak demand charges are common in commercial and industrial utility rate schedules, but not in residential schedules. For example, Public Service of New Hampshire's (PSNH's) General Service rate for small commercial customers has a distribution demand charge of $8.51/kW and a transmission demand charge of $4.61/kW applied to monthly billing demand over 5 kW (see PSNH, *Summary of Rates for Electric Service*, July 1, 2014, https://www.psnh.com/downloads/Summary_of_Rates.pdf?id=4294967859&dl=t), and Connecticut Light and Power's Small General Electric Service rate has a distribution demand charge of $6.06/kW and a transmission demand charge of $5.80/kW applied to monthly billing demand over 2 kW. See https://www.cl-p.com/Rates/Rates_and_Tariffs/.

[77] This peak demand adjustment is not applied to commercial customer types in Rhode Island (for the first 20 years of system operation) and Vermont (for the first 10 years of system operation) for 2015 project starts because the analysis assumes that those customers participate in the Renewable Energy Growth (Rhode Island) and net metering solar credit (Vermont) programs and receive performance-based compensation at fixed levels for the respective durations of those programs.

The difference between the retail and wholesale electricity prices in this analysis is multiplied by the self-generation volume each year to arrive at the driver called "incremental self-generation revenue at retail rates."[78] As with all other drivers, cash flows are then discounted at the standard rate of 10% applied throughout this analysis.

S. Net Metering Rates: Wholesale vs. Retail Compensation

Annual net metering volumes are multiplied by wholesale electricity prices to establish the driver called "net metering revenue at wholesale rates." The same net metering volumes are multiplied by the appropriate retail electricity prices for the state, customer type, and year to arrive at the driver called "full net metering revenue at retail rates."[79] As with all other drivers, cash flows are then discounted at the standard rate of 10% applied throughout this analysis.

The purpose of separating these two (wholesale vs. retail) drivers is to demonstrate the revenue that a customer would receive if net metering was allowed, but only compensated on an hourly basis at wholesale rates. For example, if net metering programs compensating participants at close to retail rates are thought in the future to over-compensate excess PV production compared to its net economic effects on the grid, there could be a policy discussion around compensating actual (on-site) and/or virtual (off-site) net metered volumes at or closer to wholesale prices. The separation of these two drivers helps clarify the potential effects on PV economics of a restriction in net metering policy and how those effects differ by state and customer type. This clarification is important given that this study assumes that existing net metering policies do not change for PV installations in all three project start years. For 2024 project starts, this means that current net metering policies (including aggregate caps) would not change over an assumed economic environment extending through 2048.

T. Renewable Energy Credits (RECs)

Annual solar renewable energy credit (SREC) price estimates are driven in a very simplified manner by state policy mechanisms in Massachusetts (SREC II)[80] and Connecticut (ZREC)[81] for

[78] The deduction of the wholesale rates is done because wholesale electricity revenues are calculated as a separate driver earlier in the analysis.

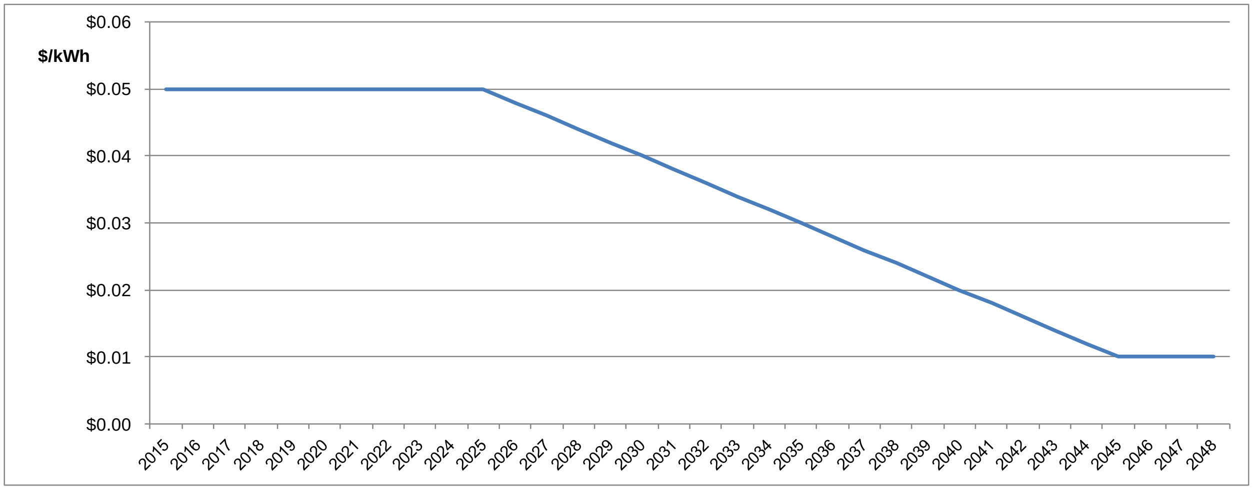
[79] Though some utilities have non-bypassable retail charges for net metering volumes, their levels vary, and they are not deducted from prices in this analysis.

[80] Massachusetts SREC prices are assumed at the SREC II annual soft auction floor prices (after administrative fee) through 2024. SREC II prices for 2025 through 2028 are assumed at $.179, $.17, $.161, and $.152/kWh, respectively. These prices apply to Massachusetts PV projects with 2015 and 2019 start years. Massachusetts residential PV projects starting in these years are assumed to be in Market Sector A (SREC price multiplication factor of 1.0), commercial projects in Market Sector B (SREC price multiplication factor of 0.9), and utility scale projects in the Managed Growth sector (SREC price multiplication factor of 0.7). In addition, it is assumed that owners of utility scale projects hedge their Massachusetts SRECs at 80% of this level to create more cash flow certainty for their projects. Massachusetts PV projects beginning in 2024 are assumed to not participate in the SREC II program, but to obtain Tier I REC prices.

[81] This analysis assumes that the small ZREC program applies to residential and commercial customer types for 2015 and 2019 project starts in Connecticut. The program is expected to end for new projects before 2024 and, therefore, is not applied to 2024 project starts. The small ZREC program has a 100 kW_{DC} size limit (equivalent to commercial customer types in this analysis). For 2015 project starts, small ZREC prices (for the 15-year term) are assumed at $.0847/kWh, which is the published Connecticut Light and Power year 3 small ZREC price ($.08097/kWh) plus one-half of the year 2 premium between United Illuminating and Connecticut Light and Power small ZREC prices. See http://www.cl-p.com/Home/SaveEnergy/GoingGreen/Renewable_Energy_Credits/ and *Year 2 Small ZREC Tariff*, Applicants Meeting, December 16, 2013, page 7, http://www.cl-p.com/downloads/Small_ZREC_Presentation.pdf?id=4294989333&dl=t. For baseline analysis of 2019 project starts,

the expected duration of those programs in relation to the starting years of projects (e.g., a qualifying 2015 or 2019 Massachusetts project could only receive SREC II prices for its first 10 years of operation and Connecticut projects for their first 15 years, and both would sell RECs beyond those program periods into the Tier 1 REC market) and by broader renewable energy credit (REC) market rules and price dynamics in other years and in other states.[82] All REC prices are in nominal dollars. Tier 1 REC price values are assumed at the levels displayed in Exhibit 3-7 below.[83]

Exhibit 3-7: Assumed Tier 1 REC Prices (in nominal dollars)



This analysis assumes that PV project owners sell (i.e., monetize), rather than retain and retire, their project SRECs. The driver "REC revenue" is calculated by multiplying the REC price each year by the PV output volume that year and applying the standard discount rate of 10% to the sum of those cash flows.

Estimating REC prices, even for a given year, is difficult. Doing so for the 25-year duration of this analysis is even more so. Providing detailed REC modeling is well beyond the scope of this effort. This analysis has attempted to make reasonable estimates, knowing that PV supply and demand dynamics, potential implementation of the U.S. Environmental Protection Agency's Clean Power Plan (Clean Air Act 111(d) regulations) in general and vis-a-vis the Regional

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small ZREC prices were assumed at $.076/kWh. The study also calculated results for two alternative scenarios for 2019 project starts: (i) 2019 ZREC rates remaining at 2015 project start levels, and (ii) the incentive being unavailable. The alternative scenario results are in Appendices D and E. The methodologies for the baseline and alternative scenario levels are described in Section 4.5.

[82] Outside of the Massachusetts SREC II and Connecticut ZREC assumptions mentioned above, it is assumed that all New England PV projects will sell their SRECs into the Massachusetts Tier I market. This includes participants in the Vermont SPEED standard offer program (utility scale customers in this analysis for 2015 and 2019 project starts) and net metering solar credit (residential and commercial customers for 2015 and 2019 project starts) programs. This analysis credits participants in the Rhode Island Renewable Energy Growth Program with REC revenues in the results by deducting each year's assumed Tier I REC price from the assumed 20-year Renewable Energy Growth bundled (physical power and REC) tariff price for the corresponding customer class.

[83] This graph reflects Tier 1 REC prices at $.05/kWh from 2015 through 2025, and then declining by $.002/kWh annually until 2045 and remaining at the 2045 level of $.01/kWh through 2048. Conducting detailed REC market analysis is beyond the scope of this project, and forecasting REC prices is highly uncertain. These assumed REC prices reflect a simplified version of REC market dynamics.

Greenhouse Gas Initiative, and other market, legislative, and regulatory factors will affect SREC and REC prices in practice.

U. Property and Sales Tax Exemptions

Property and sales taxes are added to PV project costs earlier in the analysis so that the value of tax exemptions can be displayed. The identification of tax exemptions for given states and customer classes is based upon interpretation of prevailing exemption rules at the time of the analysis.[84]

The driver "property & sales tax exemptions" is the sum over the 25-year project duration, at the standard discount rate of 10%, of (i) a recurring annual property tax calculated per the "Property Tax" subsection above if there is a property tax exemption, and (ii) a one-time state sales tax calculated per the "Installed Cost" subsection above if there is a state-level exemption.

V. Other Major State Incentives

This category includes state PV incentives in addition to RECs, property and sales tax exemptions, and net metering policies. For this analysis, up to one other "major state incentive" is applied per project, with the exception for Vermont commercial customer types as described below. Selecting if there is such an incentive for a given customer type in a state, whether the incentive is available to a wide enough group of customers and has sufficient funding to be included, and what the legislative or regulatory outlook is for its renewal or extension is an inherently subjective endeavor. Further, the scope of this analysis does not include review of all of the PV incentives that may exist at the state, local, or utility level at a given time and their sometimes complex eligibility and funding background. For this analysis, the "other major state incentives" listed below have been included, with all data applied in nominal dollars.[85]

- Connecticut: Residential solar investment program.[86]

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[84] There is no sales tax in New Hampshire and no sales tax is applied to PV installed costs for that state earlier in the analysis; therefore, a sales tax exemption is irrelevant in that state. Property tax exemptions will be applied to residential and commercial systems in New Hampshire. There are no prevalent property or sales tax exemptions for PV in Maine. Sales tax exemptions are assumed for all customer types in Connecticut, Massachusetts, and Rhode Island and for residential and commercial customers in Vermont. Property tax exemptions in the remaining states are applied as follows: Connecticut (full exemption for all customers); Massachusetts (no exemption due to assumed state treatment of all third-party owned PV systems); Rhode Island (40% exemption for residential customer types and 20% exemption for commercial and utility scale customer types); and Vermont (full exemption, including from state capacity tax, for residential customer types only). The source of the Rhode Island exemption percentages is: Sustainable Energy Advantage, LLC, *Rhode Island Renewable Energy Growth Program: 2nd Revision to Proposed 2015 Ceiling Price Recommendations*, December 9, 2014, page 12, http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf. For more information on PV property and sales tax exemptions, see Database of State Incentives for Renewables & Efficiency (DSIRE)™, http://www.dsireusa.org/.

[85] For more information on PV incentives, including those incorporated in this analysis and others, see Database of State Incentives for Renewables & Efficiency (DSIRE)™, http://www.dsireusa.org/.

[86] For residential customers with 2015 project starts, a performance-based incentive equal to $.082/kWh for the first six years of PV output is applied. That is the average of estimated step 6 and step 7 incentive levels appropriate to third-party owned PV systems like those modeled in this analysis. Though Step 6 and Step 7 incentive do not appear to be available at the time of writing, Connecticut stakeholders in the DGFWG suggested that 2015 projects would likely receive Step 6 early in 2015 and Step 7 later in the year. Step 6 and 7 levels were estimated based upon the approximate average historical reductions between Steps 2 through 5 in the program. Due to the history of incentive

- Maine: None applied.
- Massachusetts: None applied.[87]
- New Hampshire: Residential small renewable electrical generation systems rebate and commercial & industrial incentive program.[88]
- Rhode Island: Renewable Energy Growth Program.[89],[90]

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step-downs in this program, this incentive is not applied to 2019 or 2024 project starts. For more program information, see http://www.energizect.com/residents/programs/residential-solar-investment-program.

[87] The Commonwealth Solar II rebate program for small (under 15 kW) systems is not utilized in this analysis because Block 20 is the final funding block in the program, and it was fully subscribed as of October 20, 2014. See Massachusetts Clean Energy Center, http://www.masscec.com/solicitations/commonwealth-solar-ii-block-20.

[88] The state indicates that the residential program, which offers rebates of $.75/watt up to a maximum of $3,750 per project, has funding currently available. Funding is also available for the commercial program, which offers rebates of $.80/watt up to $50,000 per project (for systems up to 100 kW in capacity). For this analysis, 2015 residential and commercial project starts are assumed to obtain their respective maximum rebates. See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NH32F&re=0&ee=0, New Hampshire Public Utilities Commission, http://www.puc.nh.gov/Sustainable%20Energy/RenewableEnergyRebates-SREG.html, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NH44F&re=0&ee=0, and New Hampshire Public Utilities Commission, http://www.puc.nh.gov/Sustainable%20Energy/RenewableEnergyRebates-CI.html. The Public Utilities Commission is reviewing a proposal to reduce the commercial and industrial rebate. See Eckberg, Stephen, New Hampshire Public Utilities Commission, *New Hampshire Policies Supporting Distributed Generation*, ISO-New England Distributed Generation Forecast Working Group, December 15, 2014, http://www.iso-ne.com/static-assets/documents/2014/12/nh_dgfwg_presentation_121515.pdf. For the baseline analysis, the rebates are assumed to decline to values of $2,888 (residential 2019 project starts), $1,800 (residential 2024 project starts), $38,500 (commercial 2019 project starts), and $24,000 (commercial 2024 project starts). The study also calculated results for two alternative scenarios for 2019 and 2024 project starts: (i) 2019 and 2024 rebates remaining at 2015 levels, and (ii) the incentive being unavailable. The alternative scenario results are in Appendices D and E. The methodologies for the baseline and alternative scenario levels are described in Section 4.5.

[89] Rhode Island is implementing a Renewable Energy Growth Program that includes a performance-based incentive for which PV is eligible. That program's first group of tariffs and procurement rules may not be approved until the first half of 2015. See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=RI37F&re=0&ee=0 and State of Rhode Island Office of Energy Resources, *Rhode Island Solar Forecast*, presented at ISO-NE Distributed Generation Forecast Working Group, December 15, 2014, pages 4-6, http://www.iso-ne.com/static-assets/documents/2014/12/ri_dgfwg_presentation_121514.pdf. This program will establish separate 20-year prices that are applicable to each of the three customer types analyzed in this report. Specifically, the program has tariff rates for third-party owned small solar I (1-10 kW) applicable to residential customer types in this analysis and medium scale solar (26-250 kW) applicable to commercial customer types, and a ceiling price for large solar (1,000 to 5,000 kW) applicable to utility scale customer types. In this analysis, the draft recommended tariff and ceiling prices for these three size categories are applied to 2015 project starts for their first 20 years of operation. These ceiling prices are assumed to include both physical power and RECs associated with all PV production and are $.3295/kWh for third-party owned small solar (residential), $.244/kWh for medium scale (commercial), and $.167/kWh for large solar (utility scale). See Sustainable Energy Advantage, LLC, *Rhode Island Renewable Energy Growth Program: 2nd Revision to Proposed 2015 Ceiling Price Recommendations*, December 9, 2014, page 2, http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf. For the purposes of displaying results, volumes are divided between self generation and net metered according to the method described in subsections 3.3 D and E above. Because the Renewable Energy Growth Program is designed to finance renewable energy projects through 2019, and future ceiling price levels are unknown, the study's baseline assumption is that ceiling prices for 2019 project starts will be reduced to $.313/kWh (residential), $.24/kWh (commercial), and $.16/kWh (utility scale). The study also calculated results for two alternative scenarios for 2019 project starts: (i) 2019 rates remaining at 2015 levels, and (ii) the incentive being unavailable. The alternative scenario results are in Appendices D and E. The methodologies for the baseline and alternative scenario levels are described in Section 4.5.

[90] Rhode Island residential and commercial PV projects could access Renewable Energy Fund grants instead of the upcoming Renewable Energy Growth Program. This analysis assumes that more projects (and a higher proportion of

- Vermont: SPEED standard offer program,[91] solar net metering program,[92] and investment tax credit.[93]

The driver "other major state incentives" is the 25-year cash flow from the incentive at the standard discount rate of 10% applied to each combination of customer type, state, and project start year.

W. Discount Rate

A 10% discount rate[94] is applied for this analysis and is the assumed nominal rate of return threshold required for all equity investments in the PV projects. That discount rate is applied to each economic driver to calculate the driver's per kWh effect on PV economics. The 10% discount rate is applied to all future costs and benefits of the PV projects, which can be considered moderate risk investments.

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customers) will use the Renewable Energy Growth Program due to its greater size (i.e., capacity goals that may be supported under it).

[91] The Vermont Sustainably Priced Energy Enterprise Development (SPEED) standard offer program allows for feed-in-tariff payments to PV projects at a maximum rate of $.257/kWh for 25 years. See http://vermontspeed.com/. The program is part of a 2022 Vermont renewable energy goal. This analysis assumes that utility scale projects with 2015 project starts in Vermont will participate in SPEED, receive the average of the high and low rates for their energy from the 2014 auction (i.e., an average rate of $.124/kWh), and also be able to sell project RECs into the Tier I market outside of Vermont (as they are at present). For 2019 project starts, the auction rate assumed for utility scale customers is $.12/kWh. This program is not applied to 2024 project starts because its capacity goals are intended to be reached by that time. For information on standard offer program auction rates, see Walter (TJ) Poor, Vermont Department of Public Service, *Vermont Distributed Generation: 2015-2024 Expectations*, ISO-New England Distributed Generation Forecast Working Group, December 15, 2014, page 4, http://www.iso-ne.com/static-assets/documents/2014/12/vt_dgwg_presentation_121514.pdf. For displaying table and chart results, SPEED volumes are labeled as net metering (this analysis divides all PV production volumes into self-generation, net metered, or general wholesale rate categories). The study also calculated results for two alternative scenarios for 2019 project starts: (i) 2019 rates remaining at 2015 levels, and (ii) the incentive being unavailable. The alternative scenario results are in Appendices D and E. The methodologies for the baseline and alternative scenario levels are described in Section 4.5.

[92] This analysis assumes that, for 2015 project starts, residential customer types receive any positive difference between $.20/kWh and their residential retail electricity rates for PV output for the first 10 years of project operation and that commercial customer types similarly receive any positive difference between $.19/kWh and their commercial retail electricity rates for PV output for the first 10 years of project operation. Customers revert to simply having their retail electricity rates offset by PV production for years 11 through 25 of project operation. For 2019 project starts, the assumed levels of this incentive are $.20/kWh (residential) and $.186/kWh (commercial). This program is not applied to 2024 project starts because conventional utility rates are assumed to exceed the incentive level by that time. For more information on this program, see Walter (TJ) Poor, Vermont Department of Public Service, *Vermont Distributed Generation: 2015-2024 Expectations*, ISO-New England Distributed Generation Forecast Working Group, December 15, 2014, page 7, http://www.iso-ne.com/static-assets/documents/2014/12/vt_dgwg_presentation_121514.pdf. In the analysis results, the net metering solar credit value is contained in the driver "full net metering revenue at retail rates." The study also calculated results for two alternative scenarios for 2019 project starts: (i) 2019 rates remaining at 2015 levels, and (ii) the incentive being unavailable. The alternative scenario results are in Appendices D and E. The methodologies for the baseline and alternative scenario levels are described in Section 4.5. The baseline methodology for 2019 project starts held the incentive constant for residential customers at 2015 levels, so the first alternative scenario is the same as the baseline scenario in this instance.

[93] Vermont has an investment tax credit applicable to commercial, industrial, and agricultural applications of PV and other renewable technologies. The Vermont credit is applied in this analysis to commercial projects at 7.2% of (pre-sales tax) installed cost for 2015 project starts and 2.4% of (pre-sales tax) installed cost for 2019 and 2024 project starts. Installed costs before sales tax are used due to the prevalence of PV sales tax exemptions in New England. This credit follows the Federal investment tax credit, which declines starting January 1, 2017. See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT37F&re=0&ee=0.

[94] Discount rate can be interpreted as the rate of return that the investor requires to proceed with the project.

An alternative 5% discount rate is also applied in this analysis. This lower discount rate can be seen as representing the investment perspective of entities with less aggressive rate of return goals for PV projects (e.g., that ascribe large environmental or societal values to PV projects and/or do not have high-return investment alternatives). This 5% discount rate is much lower than typically required by independent power producers investing equity in utility scale projects or solar developers/financiers investing equity in portfolios of distributed PV projects.

The driver "effect of lower discount rate" is the difference between the per kWh value for fully supported PV economics at a 10% discount rate and at a 5% discount rate.

4. OUTPUTS OF ANALYSIS

4.1 Overview

In order to create output values for each of the 16 "drivers" (positive or negative contributors to PV economics) reviewed in this report, the cash flow from each driver is calculated for 25 years in nominal dollars and then discounted to present dollars associated with the project start year.[95] Annual PV production volumes are discounted at the same rate.

All data analyses are on an annualized basis. The only exception to the annualized analyses is that PV production, on-site electricity consumption, self-generation volumes, and net metered volumes are calculated hourly and, then, aggregated into annual totals.

All results are presented in $/kWh, in order to be comparable to how customers and utilities typically think about electricity costs. The contribution of each driver to PV economics can be interpreted from its $/kWh value. The calculation process is repeated for each of the 54 combinations of state, customer type, and project starting year considered. The 54 (= 6 x 3 x 3) combinations are comprised of:

- *Six New England states: Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire, and Maine*
- *Three customer types: residential, commercial, and utility scale*
- *Three project starts (years when the PV system enters operation): 2015, 2019, and 2024*

Data are presented for all 54 combinations for the "baseline" set of assumptions applied in the study. In addition, there are two alternative scenarios provided for reference. Those alternative scenarios, defined in Section 4.5, present differing assumptions about the levels of certain state PV programs for which future incentive values are not firmly established at this time or are otherwise difficult to ascertain. Alternative scenario results are shown in Appendices D and E in tabular form if they differ from baseline results.

4.2 Summary Measures

The results from the individual drivers are sub-totaled to generate the five summary measures presented: (i) levelized cost of energy, (ii) unsupported PV economics, (iii) Federally supported

[95] All data are assumed to be in after income tax dollars.

PV economics, (iv) fully supported PV economics, and (v) fully supported PV economics with lower discount rate. These summary measures are neither drivers nor influencers of PV economics themselves, but instead represent five different ways of thinking about holistic PV economics. Depending on the decision or question at hand, different summary measures may be most useful. Each of the five summary measures is described in more detail below.

A. Levelized Cost of Energy (LCOE)

LCOE represents the cost of a PV project before it earns any revenues or receives any special incentives. LCOE as calculated in this analysis includes the full installed (capital and labor) cost of the project, O&M costs, property taxes, and inverter replacement costs, less straightline Federal depreciation. Because businesses can depreciate all qualifying tangible investments, even those without special incentives like PV, with straightline depreciation (deducting equal percentages of the cost each year of the taxable property life), including this driver in LCOE provides a more accurate picture of the net costs of a project than excluding it.[96]

LCOE is sometimes used to compare the relative costs of electricity generation projects or technologies. However, simply comparing LCOE between very different generation technologies can lead to misleading outcomes due to large variations in incentives, asset life, and other factors between technologies.

LCOE can also be used for comparison with a generation project's revenue potential; i.e., levelized revenues may need to exceed levelized costs to assure project profitability.

B. Unsupported PV Economics

In order to demonstrate the worst-case scenario of a PV project that receives no Federal incentives, no other incentives, and no sophisticated financial engineering and has its electricity output treated like that of a general supplier of wholesale grid power, this report presents the "unsupported PV economics" measure.

C. Federally Supported PV Economics

Federally supported PV economics applies both the Federal investment tax credit (ITC) and the incremental effect of Federal accelerated depreciation (i.e., the value of accelerated depreciation above that of straightline depreciation) to unsupported PV economics.[97] The Federally supported measure can be interpreted as PV economics with the project only receiving wholesale prices for its output and before any state, local, or utility incentives.

[96] There are a range of definitions of LCOE in the electricity industry. In some instances, depreciation is excluded. In others, capital-based incentives are deducted from installed costs. Any of these can be valid metrics depending on the purpose at hand. It is important, though, to know the LCOE methodology if one compares results of different analyses.

[97] If a PV owner does not have the ability to monetize tax benefits from outright purchase of a PV system (e.g., because it is a non-profit or public agency), then the ITC and accelerated depreciation would not contribute to the economics of its PV system. For that owner, "Federally supported PV economics" would equal "unsupported PV economics" (and the level of those two summary measures would be even a little higher than calculated here (less favorable) due to the absence of straightline depreciation for this owner). The owner, however, could receive the benefit of the incremental drivers described after "Federally supported PV economics" if those benefits are not based in the tax code.

D. Fully Supported PV Economics

This measure reflects the best-case scenario for PV projects at the standard discount rate of 10% used in the analysis. In addition to the revenues and costs included in Federally supported PV economics, the summary measure "fully supported PV economics" assumes that: the PV project, to the extent permitted by the financial model assumptions, offsets on-site retail electricity consumption, sells net metered output at retail rates, borrows money at attractive rates, sells its RECs, receives sales and property tax exemptions, and captures other major state PV incentives. In practice, savvy solar developers often utilize all of these available benefits, as well as local and utility incentives, to deliver the lowest-cost solar offer to customers.

E. Fully Supported PV Economics at Lower Discount Rate

The prior summary measures all use a standard discount rate of 10%. This measure applies a discount rate of 5% (which may be appropriate for entities or investors with a public purpose or less aggressive investment return goals) to the entire financial model. Applying the lower discount rate affects all model outputs, but what is presented in the results is just the final levelized value ($/kWh) from using the lower discount rate. The difference between this measure and the prior one can be attributed to discount rate effects.

4.3 Baseline Scenario Outputs in Table Form

Each table below (Exhibits 4-1 through 4-6) presents the baseline results for the combinations of state and customer type for each project start year.[98] The results include the $/kWh contribution to PV economics of each driver[99] and the sub-totals (in blue) for the summary measures. Exhibit 4-7 consolidates the summary measure "Fully Supported PV Economics" (at the standard 10% discount rate applied in the study) for all 54 economic cases.

[98] Results for two limited alternative scenarios are presented in Appendices D and E where those results differ from the baseline assumptions. The alternative scenarios are described in more detail in Section 4.5.
[99] For descriptions of the individual drivers of PV economics, please see Section 3 above.

Exhibit 4-1: Summary of PV Drivers by Customer Type for Connecticut, Maine, & Massachusetts, 2015 Project Starts

(Data in $/kWh)

State =>	CT	CT	CT	ME	ME	ME	MA	MA	MA
Customer Type =>	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
Installed Cost	$0.391	$0.335	$0.195	$0.409	$0.356	$0.203	$0.407	$0.352	$0.204
O&M Costs	$0.032	$0.025	$0.020	$0.034	$0.026	$0.021	$0.033	$0.026	$0.021
Property Taxes	$0.017	$0.015	$0.009	$0.018	$0.016	$0.009	$0.018	$0.015	$0.009
Inverter Replacement	$0.007	$0.006	$0.004	$0.008	$0.007	$0.004	$0.008	$0.007	$0.004
Straightline Federal Depreciation	($0.056)	($0.048)	($0.028)	($0.059)	($0.052)	($0.029)	($0.059)	($0.051)	($0.029)
Levelized Cost of Energy (LCOE) of PV	**$0.391**	**$0.332**	**$0.199**	**$0.409**	**$0.353**	**$0.207**	**$0.407**	**$0.349**	**$0.208**
Wholesale Power Revenue	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)
Unsupported PV Economics	**$0.315**	**$0.256**	**$0.123**	**$0.333**	**$0.277**	**$0.131**	**$0.331**	**$0.273**	**$0.132**
Federal Investment Tax Credit	($0.103)	($0.088)	($0.052)	($0.109)	($0.094)	($0.054)	($0.108)	($0.093)	($0.054)
Federal Accelerated Depreciation	($0.031)	($0.026)	($0.015)	($0.032)	($0.028)	($0.016)	($0.032)	($0.028)	($0.016)
Federally Supported PV Economics	**$0.181**	**$0.141**	**$0.056**	**$0.193**	**$0.155**	**$0.061**	**$0.191**	**$0.153**	**$0.062**
Lower Cost Debt	($0.037)	($0.031)	($0.018)	($0.038)	($0.033)	($0.019)	($0.038)	($0.033)	($0.019)
Incremental Self-Generation Revenue at Retail Rates	($0.053)	($0.040)	$0.000	($0.036)	($0.025)	$0.000	($0.042)	($0.036)	$0.000
REC Revenue	($0.077)	($0.077)	($0.047)	($0.047)	($0.047)	($0.047)	($0.184)	($0.167)	($0.108)
Net Metering Revenue at Wholesale Rates	$0.046	$0.041	$0.076	$0.047	$0.041	$0.030	$0.047	$0.041	$0.076
Full Net Metering Revenue at Retail Rates	($0.130)	($0.087)	($0.162)	($0.105)	($0.070)	($0.052)	($0.116)	($0.085)	($0.156)
Property & Sales Tax Exemptions	($0.028)	($0.024)	($0.014)	$0.000	$0.000	$0.000	($0.011)	($0.010)	($0.006)
Other Major State Incentives	($0.050)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Fully Supported PV Economics	**($0.148)**	**($0.077)**	**($0.109)**	**$0.013**	**$0.020**	**($0.026)**	**($0.152)**	**($0.137)**	**($0.151)**
Effect of Lower Discount Rate	($0.021)	($0.030)	($0.021)	($0.043)	($0.037)	($0.023)	($0.013)	($0.010)	($0.009)
Fully Supported PV Economics @ Lower Discount Rate	**($0.169)**	**($0.108)**	**($0.131)**	**($0.030)**	**($0.016)**	**($0.049)**	**($0.165)**	**($0.147)**	**($0.160)**

Exhibit 4-2: Summary of PV Drivers by Customer Type for New Hampshire, Rhode Island, & Vermont, 2015 Project Starts

(Data in $/kWh)

State =>	NH	NH	NH	RI	RI	RI	VT	VT	VT
Customer Type =>	**Residential**	**Commercial**	**Utility Scale**	**Residential**	**Commercial**	**Utility Scale**	**Residential**	**Commercial**	**Utility Scale**
Installed Cost	$0.405	$0.351	$0.200	$0.406	$0.350	$0.203	$0.446	$0.382	$0.221
O&M Costs	$0.034	$0.027	$0.021	$0.033	$0.026	$0.021	$0.036	$0.028	$0.023
Property Taxes	$0.018	$0.016	$0.009	$0.018	$0.015	$0.009	$0.020	$0.021	$0.014
Inverter Replacement	$0.008	$0.007	$0.004	$0.008	$0.006	$0.004	$0.008	$0.007	$0.004
Straightline Federal Depreciation	($0.060)	($0.052)	($0.030)	($0.058)	($0.050)	($0.029)	($0.065)	($0.055)	($0.032)
Levelized Cost of Energy (LCOE) of PV	**$0.405**	**$0.348**	**$0.204**	**$0.406**	**$0.347**	**$0.207**	**$0.446**	**$0.383**	**$0.230**
Wholesale Power Revenue	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)	($0.076)
Unsupported PV Economics	**$0.329**	**$0.272**	**$0.129**	**$0.330**	**$0.271**	**$0.131**	**$0.370**	**$0.308**	**$0.154**
Federal Investment Tax Credit	($0.110)	($0.096)	($0.055)	($0.107)	($0.092)	($0.053)	($0.118)	($0.101)	($0.059)
Federal Accelerated Depreciation	($0.033)	($0.028)	($0.016)	($0.032)	($0.027)	($0.016)	($0.035)	($0.030)	($0.017)
Federally Supported PV Economics	**$0.186**	**$0.148**	**$0.058**	**$0.191**	**$0.152**	**$0.062**	**$0.217**	**$0.176**	**$0.078**
Lower Cost Debt	($0.039)	($0.034)	($0.019)	($0.038)	($0.033)	($0.019)	($0.042)	($0.036)	($0.021)
Incremental Self-Generation Revenue at Retail Rates	($0.046)	($0.035)	$0.000	($0.078)	($0.055)	$0.000	$0.000	$0.000	$0.000
REC Revenue	($0.047)	($0.047)	($0.047)	($0.047)	($0.047)	($0.047)	($0.047)	($0.047)	($0.047)
Net Metering Revenue at Wholesale Rates	$0.047	$0.041	$0.046	$0.047	$0.041	$0.076	$0.076	$0.076	$0.076
Full Net Metering Revenue at Retail Rates	($0.120)	($0.081)	($0.091)	($0.173)	($0.107)	($0.124)	($0.211)	($0.192)	($0.124)
Property & Sales Tax Exemptions	($0.018)	($0.016)	$0.000	($0.020)	($0.014)	($0.008)	($0.031)	($0.010)	$0.000
Other Major State Incentives	($0.066)	($0.049)	$0.000	$0.000	$0.000	$0.000	$0.000	($0.024)	$0.000
Fully Supported PV Economics	**($0.103)**	**($0.072)**	**($0.053)**	**($0.117)**	**($0.063)**	**($0.061)**	**($0.038)**	**($0.057)**	**($0.038)**
Effect of Lower Discount Rate	($0.020)	($0.019)	($0.022)	($0.032)	($0.029)	($0.021)	($0.042)	($0.025)	($0.018)
Fully Supported PV Economics @ Lower Discount Rate	**($0.123)**	**($0.091)**	**($0.075)**	**($0.148)**	**($0.092)**	**($0.081)**	**($0.080)**	**($0.082)**	**($0.056)**

Exhibit 4-3: Summary of PV Drivers by Customer Type for Connecticut, Maine, & Massachusetts, 2019 Project Starts

(Data in $/kWh)

State =>	CT	CT	CT	ME	ME	ME	MA	MA	MA
Customer Type =>	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
Installed Cost	$0.366	$0.314	$0.183	$0.383	$0.334	$0.190	$0.381	$0.330	$0.191
O&M Costs	$0.033	$0.025	$0.020	$0.034	$0.027	$0.021	$0.034	$0.027	$0.021
Property Taxes	$0.016	$0.014	$0.008	$0.017	$0.015	$0.008	$0.017	$0.015	$0.008
Inverter Replacement	$0.007	$0.006	$0.003	$0.007	$0.006	$0.004	$0.007	$0.006	$0.004
Straightline Federal Depreciation	($0.053)	($0.045)	($0.026)	($0.056)	($0.048)	($0.028)	($0.055)	($0.048)	($0.028)
Levelized Cost of Energy (LCOE) of PV	**$0.369**	**$0.313**	**$0.188**	**$0.386**	**$0.333**	**$0.196**	**$0.384**	**$0.330**	**$0.197**
Wholesale Power Revenue	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)
Unsupported PV Economics	**$0.279**	**$0.223**	**$0.098**	**$0.296**	**$0.243**	**$0.106**	**$0.294**	**$0.240**	**$0.107**
Federal Investment Tax Credit	($0.032)	($0.028)	($0.016)	($0.034)	($0.030)	($0.017)	($0.034)	($0.029)	($0.017)
Federal Accelerated Depreciation	($0.038)	($0.033)	($0.019)	($0.040)	($0.035)	($0.020)	($0.040)	($0.035)	($0.020)
Federally Supported PV Economics	**$0.208**	**$0.163**	**$0.063**	**$0.222**	**$0.179**	**$0.069**	**$0.220**	**$0.176**	**$0.070**
Lower Cost Debt	($0.034)	($0.029)	($0.017)	($0.036)	($0.031)	($0.018)	($0.036)	($0.031)	($0.018)
Incremental Self-Generation Revenue at Retail Rates	($0.055)	($0.040)	$0.000	($0.036)	($0.023)	$0.000	($0.043)	($0.036)	$0.000
REC Revenue	($0.068)	($0.068)	($0.044)	($0.044)	($0.044)	($0.044)	($0.151)	($0.136)	($0.089)
Net Metering Revenue at Wholesale Rates	$0.055	$0.048	$0.090	$0.055	$0.049	$0.036	$0.056	$0.049	$0.090
Full Net Metering Revenue at Retail Rates	($0.141)	($0.094)	($0.176)	($0.114)	($0.076)	($0.056)	($0.126)	($0.092)	($0.169)
Property & Sales Tax Exemptions	($0.026)	($0.023)	($0.013)	$0.000	$0.000	$0.000	($0.010)	($0.009)	($0.005)
Other Major State Incentives	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Fully Supported PV Economics	**($0.061)**	**($0.043)**	**($0.097)**	**$0.048**	**$0.053**	**($0.013)**	**($0.089)**	**($0.080)**	**($0.121)**
Effect of Lower Discount Rate	($0.054)	($0.045)	($0.029)	($0.059)	($0.050)	($0.031)	($0.035)	($0.030)	($0.020)
Fully Supported PV Economics @ Lower Discount Rate	**($0.115)**	**($0.088)**	**($0.126)**	**($0.011)**	**$0.002**	**($0.044)**	**($0.124)**	**($0.109)**	**($0.141)**

Exhibit 4-4: Summary of PV Drivers by Customer Type for New Hampshire, Rhode Island, & Vermont, 2019 Project Starts

(Data in $/kWh)

State =>	NH	NH	NH	RI	RI	RI	VT	VT	VT
Customer Type =>	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
Installed Cost	$0.379	$0.329	$0.188	$0.380	$0.328	$0.190	$0.417	$0.358	$0.208
O&M Costs	$0.035	$0.027	$0.022	$0.034	$0.026	$0.021	$0.037	$0.029	$0.023
Property Taxes	$0.017	$0.015	$0.009	$0.017	$0.014	$0.008	$0.018	$0.020	$0.013
Inverter Replacement	$0.007	$0.006	$0.004	$0.007	$0.006	$0.004	$0.008	$0.007	$0.004
Straightline Federal Depreciation	($0.056)	($0.049)	($0.028)	($0.055)	($0.047)	($0.027)	($0.060)	($0.052)	($0.030)
Levelized Cost of Energy (LCOE) of PV	**$0.382**	**$0.328**	**$0.194**	**$0.383**	**$0.327**	**$0.196**	**$0.421**	**$0.362**	**$0.217**
Wholesale Power Revenue	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)
Unsupported PV Economics	**$0.292**	**$0.238**	**$0.104**	**$0.293**	**$0.237**	**$0.106**	**$0.331**	**$0.272**	**$0.127**
Federal Investment Tax Credit	($0.034)	($0.030)	($0.017)	($0.033)	($0.029)	($0.017)	($0.037)	($0.032)	($0.018)
Federal Accelerated Depreciation	($0.041)	($0.036)	($0.020)	($0.040)	($0.034)	($0.020)	($0.044)	($0.038)	($0.022)
Federally Supported PV Economics	**$0.217**	**$0.173**	**$0.066**	**$0.220**	**$0.174**	**$0.069**	**$0.250**	**$0.203**	**$0.087**
Lower Cost Debt	($0.037)	($0.032)	($0.018)	($0.035)	($0.031)	($0.018)	($0.039)	($0.034)	($0.019)
Incremental Self-Generation Revenue at Retail Rates	($0.046)	($0.034)	$0.000	($0.068)	($0.049)	$0.000	$0.000	$0.000	$0.000
REC Revenue	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)
Net Metering Revenue at Wholesale Rates	$0.055	$0.048	$0.054	$0.056	$0.049	$0.090	$0.090	$0.090	$0.090
Full Net Metering Revenue at Retail Rates	($0.130)	($0.088)	($0.098)	($0.166)	($0.107)	($0.121)	($0.220)	($0.195)	($0.120)
Property & Sales Tax Exemptions	($0.017)	($0.015)	$0.000	($0.018)	($0.013)	($0.008)	($0.029)	($0.009)	$0.000
Other Major State Incentives	($0.048)	($0.036)	$0.000	$0.000	$0.000	$0.000	$0.000	($0.008)	$0.000
Fully Supported PV Economics	**($0.050)**	**($0.027)**	**($0.040)**	**($0.056)**	**($0.020)**	**($0.031)**	**$0.007**	**$0.003**	**($0.006)**
Effect of Lower Discount Rate	($0.042)	($0.037)	($0.030)	($0.049)	($0.044)	($0.030)	($0.061)	($0.048)	($0.026)
Fully Supported PV Economics @ Lower Discount Rate	**($0.093)**	**($0.064)**	**($0.069)**	**($0.105)**	**($0.064)**	**($0.061)**	**($0.054)**	**($0.044)**	**($0.032)**

Exhibit 4-5: Summary of PV Drivers by Customer Type for Connecticut, Maine, and Massachusetts, 2024 Project Starts

(Data in $/kWh)

State =>	CT	CT	CT	ME	ME	ME	MA	MA	MA
Customer Type =>	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
Installed Cost	$0.359	$0.308	$0.180	$0.376	$0.327	$0.187	$0.373	$0.324	$0.188
O&M Costs	$0.034	$0.026	$0.021	$0.036	$0.028	$0.022	$0.036	$0.028	$0.022
Property Taxes	$0.016	$0.014	$0.008	$0.017	$0.014	$0.008	$0.016	$0.014	$0.008
Inverter Replacement	$0.007	$0.006	$0.003	$0.007	$0.006	$0.003	$0.007	$0.006	$0.003
Straightline Federal Depreciation	($0.052)	($0.044)	($0.026)	($0.054)	($0.047)	($0.027)	($0.054)	($0.047)	($0.027)
Levelized Cost of Energy (LCOE) of PV	**$0.364**	**$0.309**	**$0.187**	**$0.381**	**$0.329**	**$0.194**	**$0.378**	**$0.325**	**$0.195**
Wholesale Power Revenue	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)
Unsupported PV Economics	**$0.254**	**$0.199**	**$0.076**	**$0.271**	**$0.219**	**$0.084**	**$0.268**	**$0.215**	**$0.084**
Federal Investment Tax Credit	($0.032)	($0.027)	($0.016)	($0.033)	($0.029)	($0.017)	($0.033)	($0.029)	($0.017)
Federal Accelerated Depreciation	($0.038)	($0.032)	($0.019)	($0.040)	($0.034)	($0.020)	($0.039)	($0.034)	($0.020)
Federally Supported PV Economics	**$0.184**	**$0.140**	**$0.042**	**$0.198**	**$0.155**	**$0.047**	**$0.196**	**$0.152**	**$0.048**
Lower Cost Debt	($0.034)	($0.029)	($0.017)	($0.035)	($0.031)	($0.018)	($0.035)	($0.030)	($0.018)
Incremental Self-Generation Revenue at Retail Rates	($0.057)	($0.040)	$0.000	($0.036)	($0.021)	$0.000	($0.044)	($0.035)	$0.000
REC Revenue	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)
Net Metering Revenue at Wholesale Rates	$0.068	$0.059	$0.110	$0.068	$0.060	$0.044	$0.068	$0.060	$0.110
Full Net Metering Revenue at Retail Rates	($0.157)	($0.105)	($0.196)	($0.126)	($0.085)	($0.062)	($0.140)	($0.102)	($0.188)
Property & Sales Tax Exemptions	($0.026)	($0.022)	($0.013)	$0.000	$0.000	$0.000	($0.010)	($0.009)	($0.005)
Other Major State Incentives	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Fully Supported PV Economics	**($0.059)**	**($0.034)**	**($0.111)**	**$0.030**	**$0.041**	**($0.026)**	**($0.001)**	**($0.002)**	**($0.090)**
Effect of Lower Discount Rate	($0.056)	($0.046)	($0.029)	($0.058)	($0.049)	($0.030)	($0.056)	($0.048)	($0.029)
Fully Supported PV Economics @ Lower Discount Rate	**($0.115)**	**($0.081)**	**($0.140)**	**($0.028)**	**($0.009)**	**($0.057)**	**($0.057)**	**($0.050)**	**($0.119)**

Exhibit 4-6: Summary of PV Drivers by Customer Type for New Hampshire, Rhode Island, & Vermont, 2024 Project Starts

(Data in $/kWh)

State =>	NH	NH	NH	RI	RI	RI	VT	VT	VT
Customer Type =>	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
Installed Cost	$0.372	$0.323	$0.185	$0.373	$0.322	$0.187	$0.409	$0.352	$0.204
O&M Costs	$0.036	$0.029	$0.023	$0.035	$0.028	$0.022	$0.039	$0.030	$0.024
Property Taxes	$0.017	$0.015	$0.008	$0.016	$0.014	$0.008	$0.018	$0.019	$0.012
Inverter Replacement	$0.007	$0.006	$0.004	$0.007	$0.006	$0.003	$0.008	$0.007	$0.004
Straightline Federal Depreciation	($0.055)	($0.048)	($0.028)	($0.054)	($0.046)	($0.027)	($0.059)	($0.051)	($0.030)
Levelized Cost of Energy (LCOE) of PV	**$0.377**	**$0.324**	**$0.192**	**$0.378**	**$0.323**	**$0.194**	**$0.415**	**$0.357**	**$0.215**
Wholesale Power Revenue	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)	($0.110)
Unsupported PV Economics	**$0.267**	**$0.214**	**$0.081**	**$0.267**	**$0.213**	**$0.084**	**$0.305**	**$0.247**	**$0.105**
Federal Investment Tax Credit	($0.034)	($0.029)	($0.017)	($0.033)	($0.028)	($0.016)	($0.036)	($0.031)	($0.018)
Federal Accelerated Depreciation	($0.040)	($0.035)	($0.020)	($0.039)	($0.034)	($0.020)	($0.043)	($0.037)	($0.021)
Federally Supported PV Economics	**$0.193**	**$0.150**	**$0.045**	**$0.196**	**$0.151**	**$0.048**	**$0.226**	**$0.179**	**$0.065**
Lower Cost Debt	($0.036)	($0.031)	($0.018)	($0.035)	($0.030)	($0.017)	($0.038)	($0.033)	($0.019)
Incremental Self-Generation Revenue at Retail Rates	($0.048)	($0.033)	$0.000	($0.045)	($0.031)	$0.000	($0.050)	($0.037)	$0.000
REC Revenue	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)	($0.037)
Net Metering Revenue at Wholesale Rates	$0.068	$0.059	$0.066	$0.068	$0.060	$0.110	$0.068	$0.059	$0.033
Full Net Metering Revenue at Retail Rates	($0.145)	($0.098)	($0.109)	($0.141)	($0.097)	($0.179)	($0.149)	($0.102)	($0.057)
Property & Sales Tax Exemptions	($0.017)	($0.015)	$0.000	($0.018)	($0.013)	($0.007)	($0.029)	($0.009)	$0.000
Other Major State Incentives	($0.029)	($0.021)	$0.000	$0.000	$0.000	$0.000	$0.000	($0.007)	$0.000
Fully Supported PV Economics	**($0.051)**	**($0.026)**	**($0.054)**	**($0.012)**	**$0.002**	**($0.083)**	**($0.010)**	**$0.012**	**($0.015)**
Effect of Lower Discount Rate	($0.048)	($0.041)	($0.029)	($0.056)	($0.047)	($0.029)	($0.062)	($0.049)	($0.034)
Fully Supported PV Economics @ Lower Discount Rate	**($0.099)**	**($0.068)**	**($0.083)**	**($0.068)**	**($0.045)**	**($0.112)**	**($0.072)**	**($0.037)**	**($0.049)**

Exhibit 4-7: Fully Supported PV Economics Summary Table

(Data in $/kWh)

State =>	CT	CT	CT	ME	ME	ME	MA	MA	MA
Customer Type =>	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
2015 Project Starts	($0.148)	($0.077)	($0.109)	$0.013	$0.020	($0.026)	($0.152)	($0.137)	($0.151)
2019 Project Starts	($0.061)	($0.043)	($0.097)	$0.048	$0.053	($0.013)	($0.089)	($0.080)	($0.121)
2024 Project Starts	($0.059)	($0.034)	($0.111)	$0.030	$0.041	($0.026)	($0.001)	($0.002)	($0.090)
State =>	NH	NH	NH	RI	RI	RI	VT	VT	VT
Customer Type =>	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
2015 Project Starts	($0.103)	($0.072)	($0.053)	($0.117)	($0.063)	($0.061)	($0.038)	($0.057)	($0.038)
2019 Project Starts	($0.050)	($0.027)	($0.040)	($0.056)	($0.020)	($0.031)	$0.007	$0.003	($0.006)
2024 Project Starts	($0.051)	($0.026)	($0.054)	($0.012)	$0.002	($0.083)	($0.010)	$0.012	($0.015)

4.4 Baseline Scenario Outputs in Waterfall Chart Form

In addition to producing the table results above, waterfall charts were generated for each of the 54 combinations of state, customer type, and project start year reviewed using the study's baseline assumptions. The waterfall charts contain the same data as the tables and have the same purpose: to display the $/kWh contribution to PV economics of each driver[100] and the sub-totals for the summary measures. The inclusion of both tables and charts in this report is intended to aid readers in using the data.

Within the waterfall charts, a green chart slice indicates an added cost (e.g., O&M) in PV economics, and a red slice indicates an added benefit or revenue item (e.g., renewable energy credits) in PV economics. The waterfall charts can most easily be interpreted by reading them from left to right. First, costs of PV ownership are built up on the left side of the charts and, then, they are decreased by various benefits that are grouped in order to separate the effects of Federal versus non-Federal support and other groupings of factors. In other words, the chart shows how much each driver affects PV economics given the analytic assumptions.

The sub-totals[101], displayed as blue plateaus in the charts, can be interpreted in relation to a zero per kWh value on the y-axis. If a sub-total is below zero on the y-axis, then the PV economics of that sub-total exceed (are better than) the discount rate. I.e., negative y-axis values in the chart signify PV investments with rates of investment return that exceed the discount rate. Positive y-axis values signify returns under the discount rate, though these returns may still be positive.

Waterfall charts for 2015 project starts are in Appendix A. The waterfall charts for 2019 and 2024 project starts are in Appendices B and C, respectively.

4.5 Alternative Scenarios

The study contains data tables, but not waterfall charts, listing results for two alternative scenarios in Appendices D and E. Those alternative scenarios are defined as:

- Alternative Scenario 1 (selected state incentives remain at 2015 levels)
- Alternative Scenario 2 (selected state incentives are unavailable).

The alternative scenarios were applied to five state incentives with program goals that extend to at least 2019 but for which 2019 and 2024 incentive levels have not been established or are not readily available. The five state incentive programs covered by the alternative scenarios are: Connecticut ZRECs (residential and commercial customer types for 2019 project starts); New Hampshire solar rebates (residential and commercial customer types for 2019 and 2024 project starts); Rhode Island Renewable Energy Growth Program (all customer types for 2019 project starts); Vermont solar net metering credits (residential and commercial customer types for 2019 project starts); and Vermont SPEED standard offer program (utility scale customer types for 2019 project starts). The baseline scenario is defined by these same five state incentives declining at the same rate that Massachusetts SREC II soft auction floor prices decline

[100] For descriptions of the individual drivers of PV economics, please see Section 3 above.
[101] The sub-totals are levelized cost of energy, unsupported PV economics, federally supported PV economics, fully supported PV economics, and fully supported PV economics with lower discount rate.

(compared to assumed Tier 1 REC prices) between 2015 and 2019 project starts. This is a total decline of 23% in the relative value of the incentive between 2015 and 2019 project starts. The alternative scenarios do not reflect a forecast of future state incentive levels nor does this report's baseline assumptions.

More information on these five state incentives policies and how their individual alternative scenarios are defined is in Sections 3.3.T and 3.3.V.

5. SUMMARY OF RESULTS

The main goal of this report is to demonstrate, under simplifying assumptions, what may be larger and smaller drivers of PV economics and how those drivers may vary over time, by customer type, and across New England states. This information may assist ISO-NE and its stakeholders in identifying and discussing salient issues that affect PV adoption in the region. This report's analysis framework is designed to be flexible enough to accommodate a range of future conditions in PV and electricity markets and to be updated or extended as warranted. The authors of this analysis hope that the report presents readers with a useful way to deconstruct PV economics.

The manner in which the methods and results of this work will inform ISO-NE's PV forecasts has not yet been fully-established and is expected to be refined by ISO-NE in consultation with the DGFWG prior to ISO-NE's next PV forecast for the region.

Given that (i) the goal of this work was not to draw conclusions nor recommendations about the New England PV market, (ii) many simplifying assumptions were made in order to standardize results across states, customer types, and time, and (iii) the ultimate use of the work in ISO-NE's forecast is still being developed, **the summary statements below should be interpreted as preliminary**.

Key results include:

- Federal incentives (the investment tax credit (ITC) and accelerated depreciation) offer substantial support to PV across the region, if they can be monetized effectively by a PV owner with tax liability. These incentives jointly decrease the cost of residential PV by approximately $.13-$.15/kWh, commercial PV by approximately $.12-$.13/kWh, and utility scale PV by approximately $.07-$.08/kWh for 2015 project starts in the region. The magnitude of these incentives demonstrates why ownership of PV systems by third parties with tax liability is a dominant model. That model is particularly effective for residential, non-profit, and government PV hosts that do not have business tax liability against which to claim Federal tax incentives, but it is also powerful for commercial PV hosts without sufficient tax liability and/or the accounting capability to optimize the tax benefits.

- The decline in the ITC (from 30% to 10% of installed cost) slated to occur on January 1, 2017, will have a large effect on PV economics. The reduction in ITC alone causes PV economics to deteriorate by about $.07-$.08/kWh for residential systems, $.06-$.07/kWh for commercial systems, and $.03-$.04/kWh for utility scale systems. It also leads to an increase in the value of accelerated depreciation (because the depreciable basis grows from 85% to 95% of installed cost), but that effect does not come close to offsetting the ITC decline.

- Not surprisingly, state incentives can make the difference between PV investments being financially attractive (well exceeding 10% discount rate targets) for certain combinations of customer types and states and being financially much less attractive elsewhere. This is because conventional utility power prices and solar resources are relatively similar across the region.

- The interplay between Federal and non-Federal PV support is made visible in the summary tables and waterfall charts. The average difference between "unsupported PV economics" and "Federally supported PV economics" declines from approximately $.11/kWh (across states and customer types) in 2015 to $.06/kWh in 2019 and stays essentially flat between 2019 and 2024. State PV support and other PV financial attributes do not, under the study assumptions, make up this full difference and, therefore, overall "fully supported PV economics" are generally less strong for 2019 and 2024 project starts than for 2015 project starts.

- PV economics across the New England states converge somewhat for 2019 and 2024 project starts compared to 2015 project starts in this analysis. This is because certain state solar incentive policies are slated to decline and end over time.

- While Federal PV support declines significantly in 2017 and state support is likely to decline over time, the economics of PV without Federal and state policy support continue to improve over time. This is due to a combination of three factors: PV installed costs are forecast to continue declining in real dollars, PV performance is estimated to improve, and PV output should continue to become more valuable as conventional physical power prices (wholesale and retail) increase. However, the results generally show that the combined effect of these positive financial influences is not sufficient to entirely counteract the impact of the planned reduction of the Federal ITC. For projects beginning in 2019, the decline in PV economics was most significant when reductions in state policy support were also assumed for policies without proscribed future values, but it persisted even when state policy support remained constant at 2015 levels for these policies.

- For PV projects that begin after the Federal ITC declines in 2017 and that do not have access to key state policies (e.g., SREC premia over Tier 1 RECs or long-term tariff, auction, or other rates), resulting PV economics rely significantly on the study's assumed continuation of state net metering policies in their current form.

- When reviewing 25-year PV economics, as this report does, small differences in inflation assumptions (e.g., for wholesale and retail electricity prices or nominal dollar increases in PV installed costs) can have substantial effects on long-term PV economics. This is both due to analysis duration and the compounding effect of inflation. Also, incentives established on fixed, nominal dollar bases (e.g., REC contract prices or performance-based incentives) today can become less beneficial in real dollars over time.

- System sizes make a large difference in the level of <u>unsupported PV economics</u>. Utility scale systems' unsupported PV economics can be 60% or more lower than residential systems and less than half of commercial systems. This is due to (i) the economies of scale involved with utility scale systems, (ii) the fact that Federal incentives do not distinguish between different system sizes or customer types (as some state PV policies do), and (iii) the practice of utility scale systems being more readily optimized in their locations to maximize their performance (i.e., south-facing, little shading, etc.). This highlights major differences between utility scale PV and smaller distributed PV -- they use very similar technologies and solar resources, but can have very different economics and policy drivers.

- Many economic drivers play a meaningful role in PV economics. Frequently, a dozen or more individual drivers can increase or decrease PV project economics by $.01/kWh or more on a levelized basis. This means that informed PV discussions should weigh many factors when predicting or evaluating deployment.

- The largest economic drivers of PV in New England tend to be: (1) system installed cost (i.e., first cost), (2) physical power revenue (wholesale, offsetting on-site electricity loads, net metering), (3) REC revenue, (4) Federal investment tax credit, and (5) Federal depreciation. Physical power revenues become increasingly important over time, while REC revenues and total Federal support tend to decline over time. The relative order of importance of these five drivers varies by state, customer type, and project start year.

- Project-specific details matter greatly. This analysis includes general assumptions in order to present standardized outputs. However, in practice, PV investment decisions are made one project at a time. This analysis is not a substitute for individual project analysis, but rather a characterization of major factors at play and how they differ in general across states and customer types and over time.

6. APPENDICES

Appendix A: Waterfall Charts for 2015 Projects Starts

Exhibit A-1: Connecticut Residential PV Drivers, 2015 Project Starts

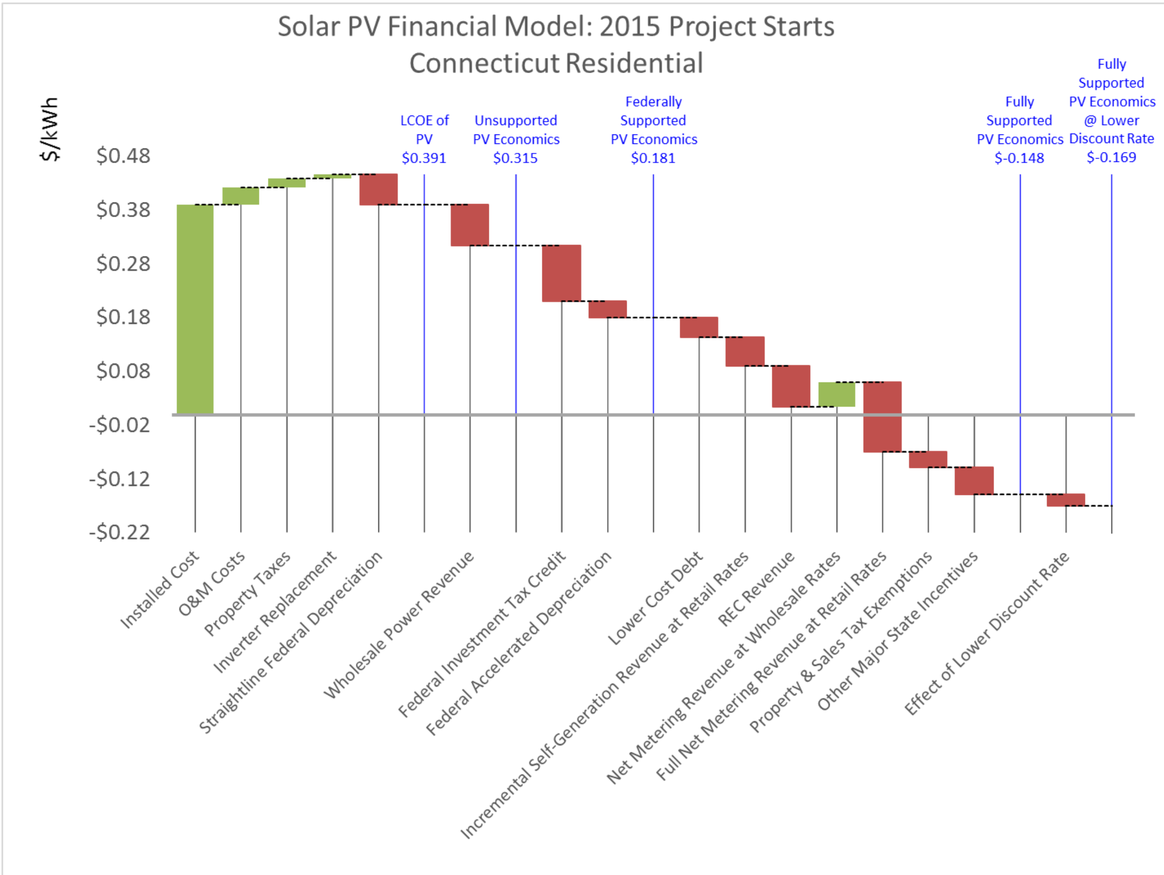


Exhibit A-2: Connecticut Commercial PV Drivers, 2015 Project Starts

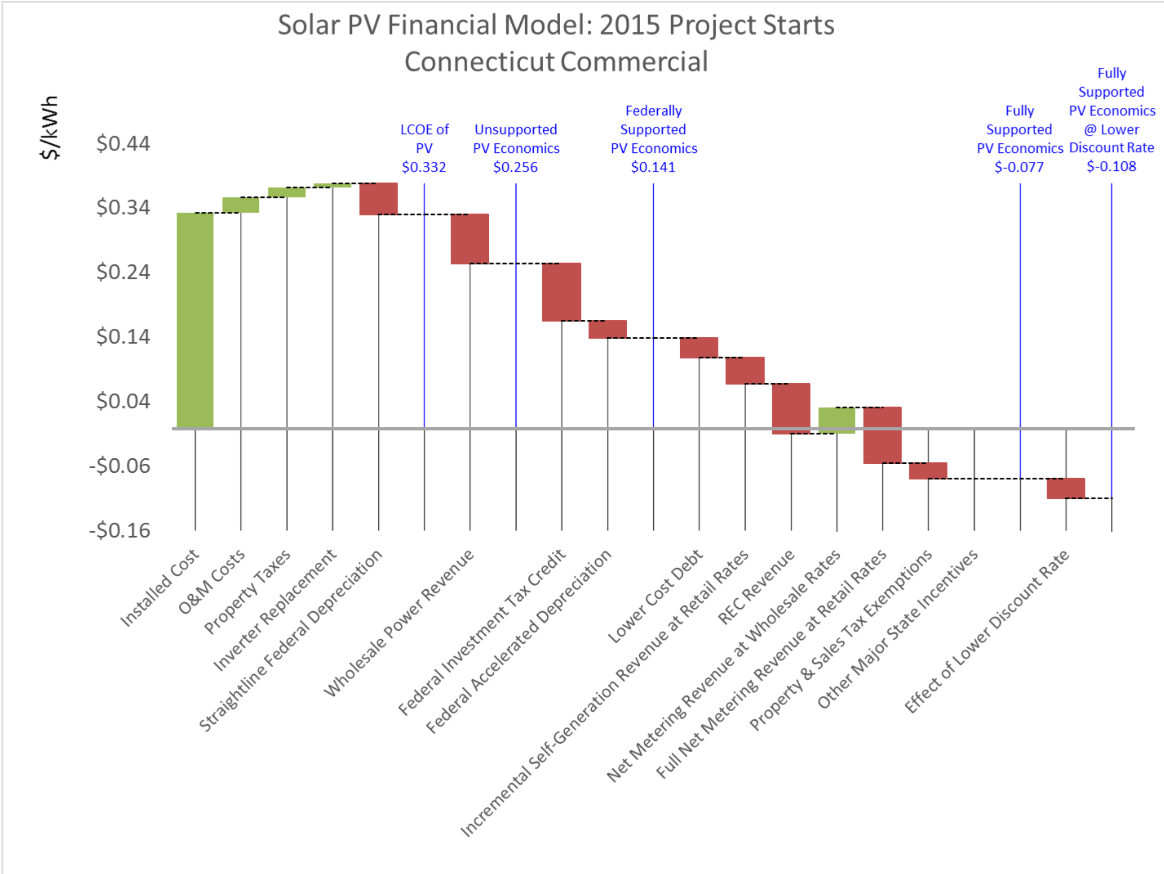


Exhibit A-3: Connecticut Utility Scale PV Drivers, 2015 Project Starts

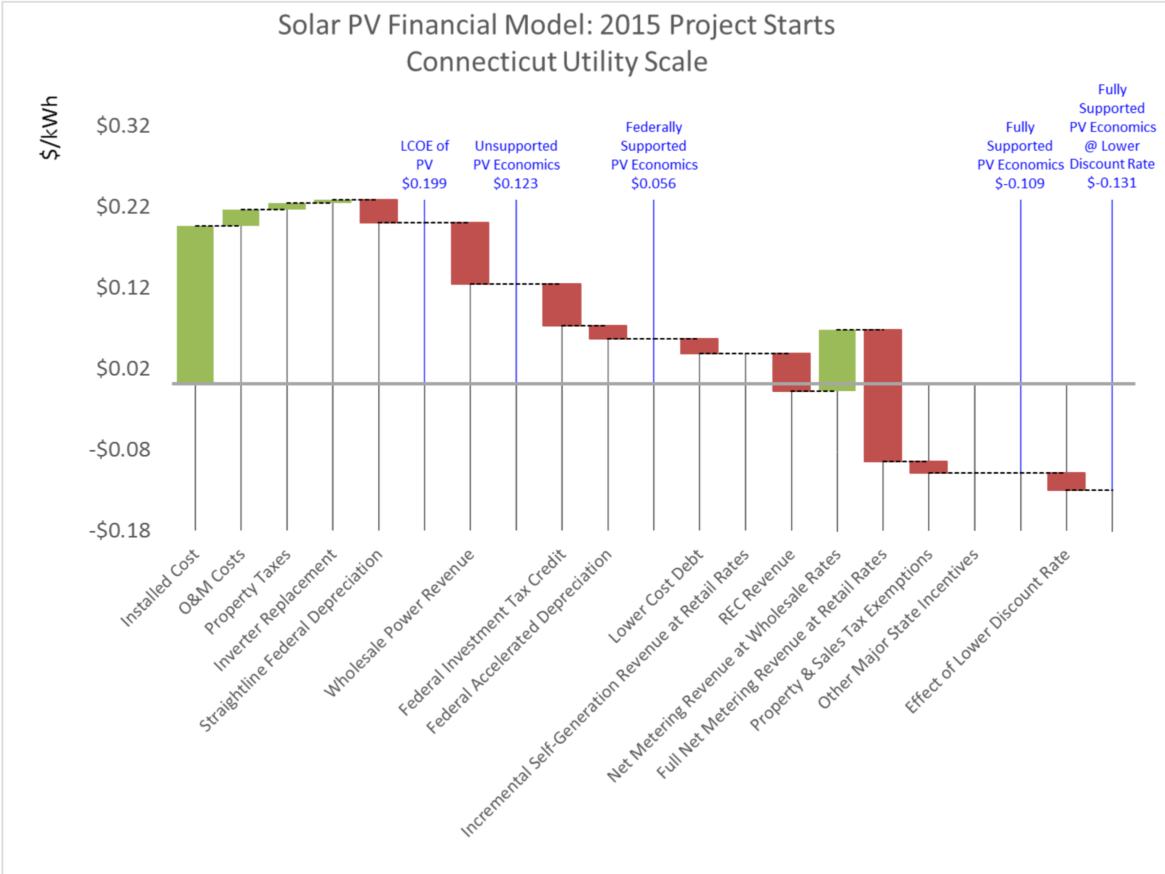


Exhibit A-4: Maine Residential PV Drivers, 2015 Project Starts

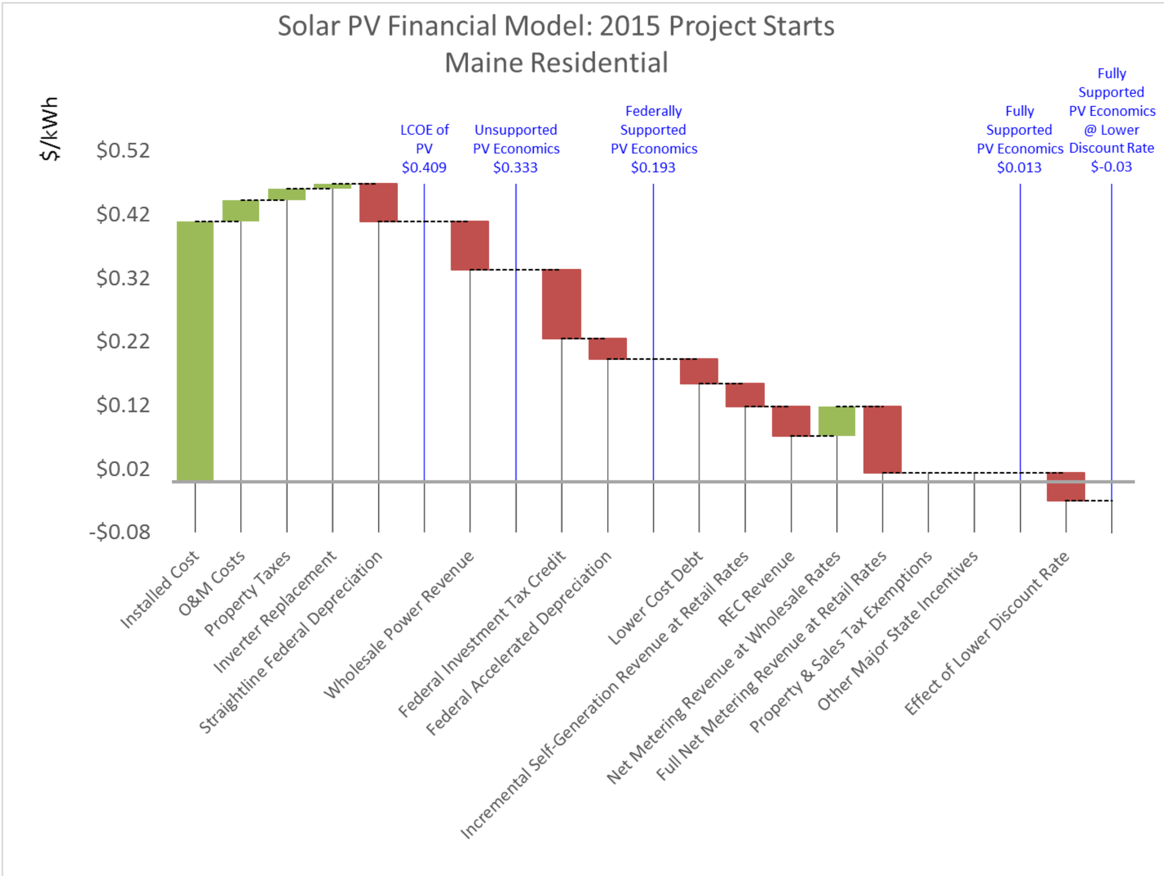


Exhibit A-5: Maine Commercial PV Drivers, 2015 Project Starts

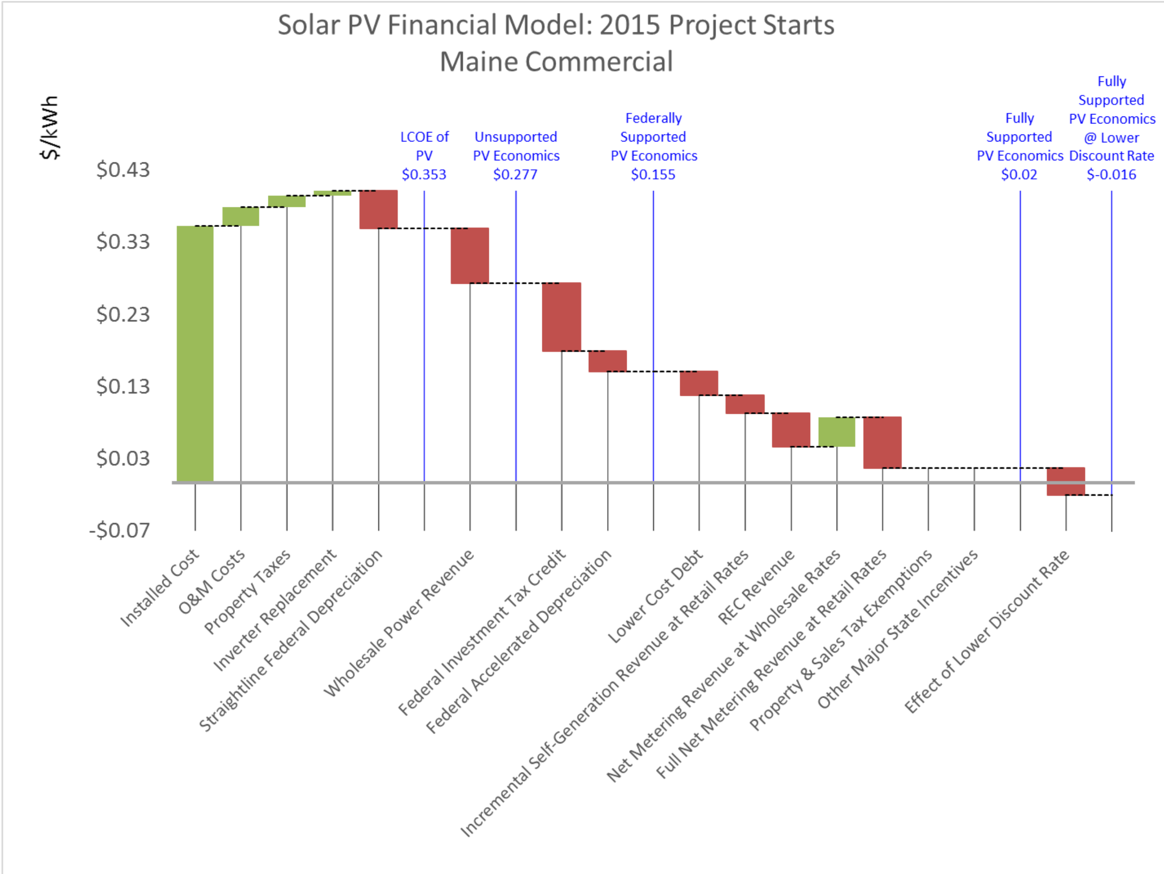


Exhibit A-6: Maine Utility Scale PV Drivers, 2015 Project Starts

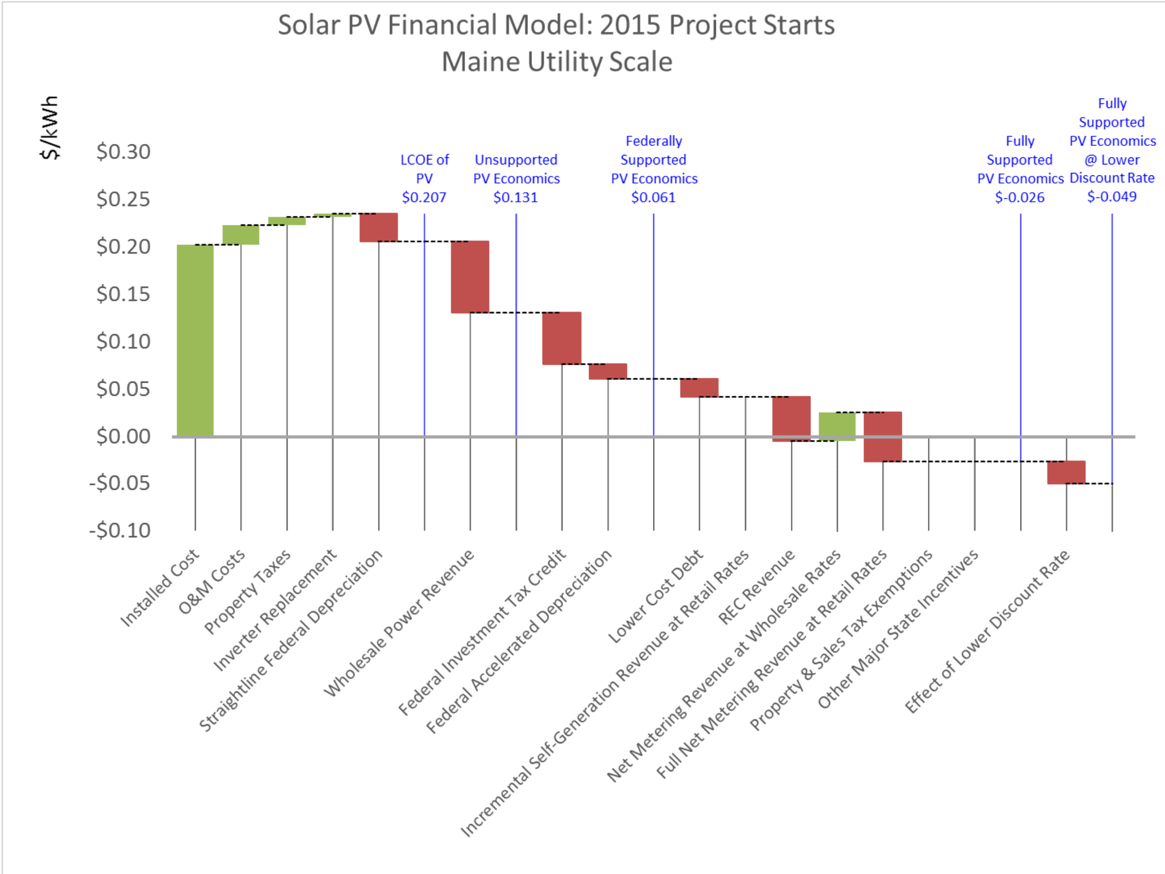


Exhibit A-7: Massachusetts Residential PV Drivers, 2015 Project Starts

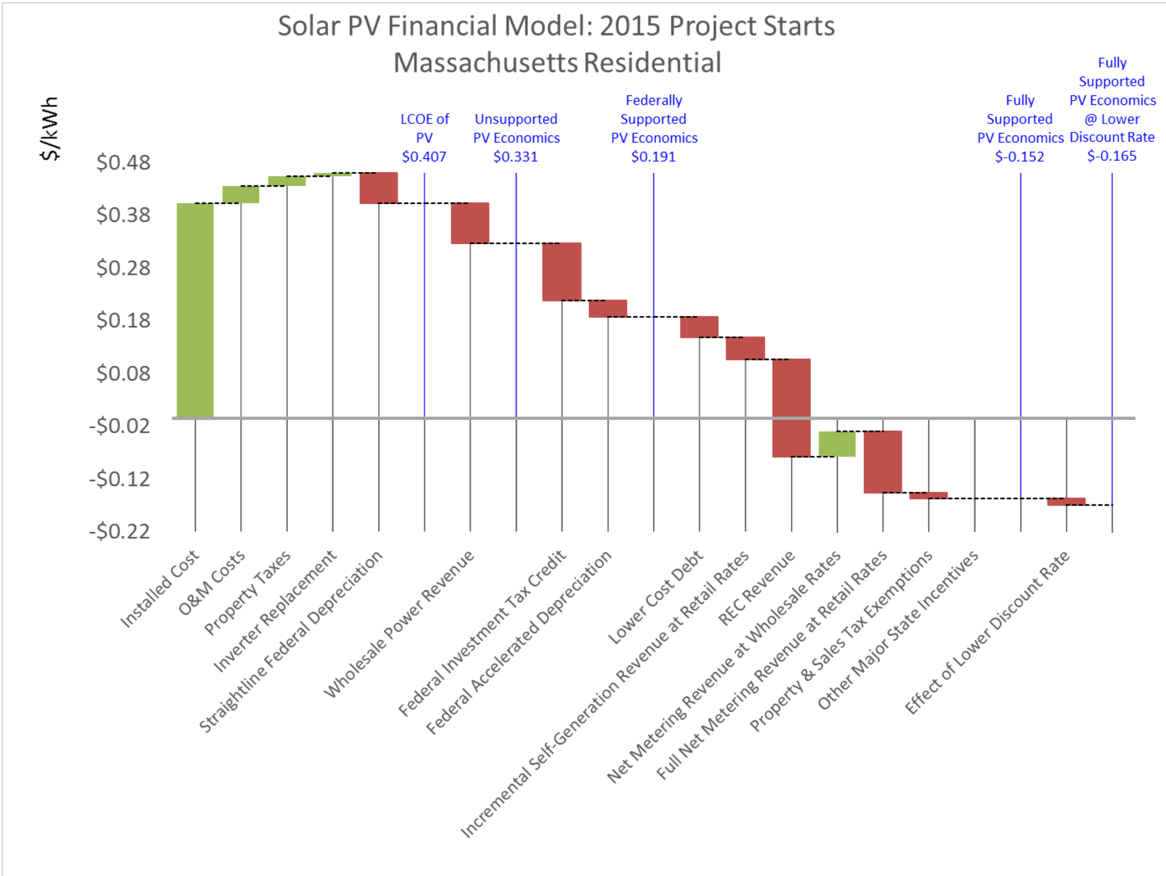


Exhibit A-8: Massachusetts Commercial PV Drivers, 2015 Project Starts

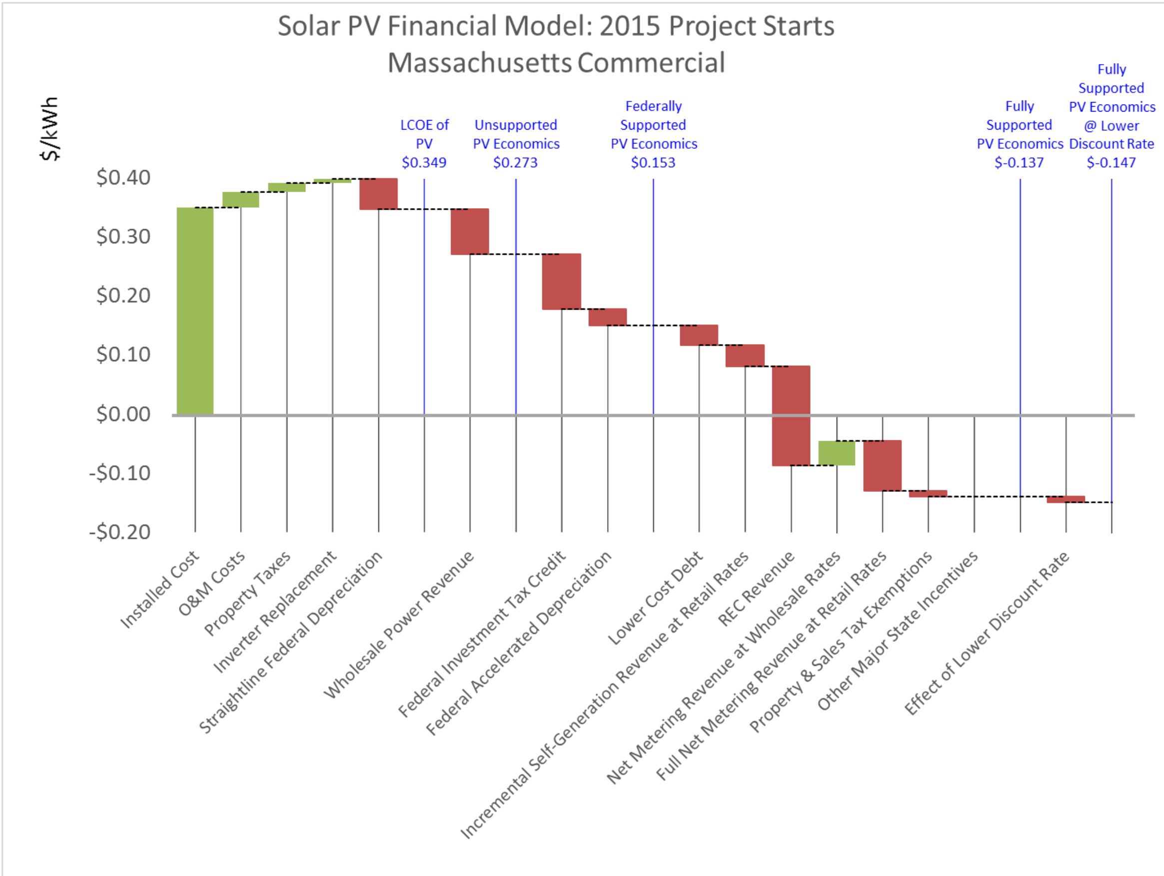


Exhibit A-9: Massachusetts Utility Scale PV Drivers, 2015 Project Starts

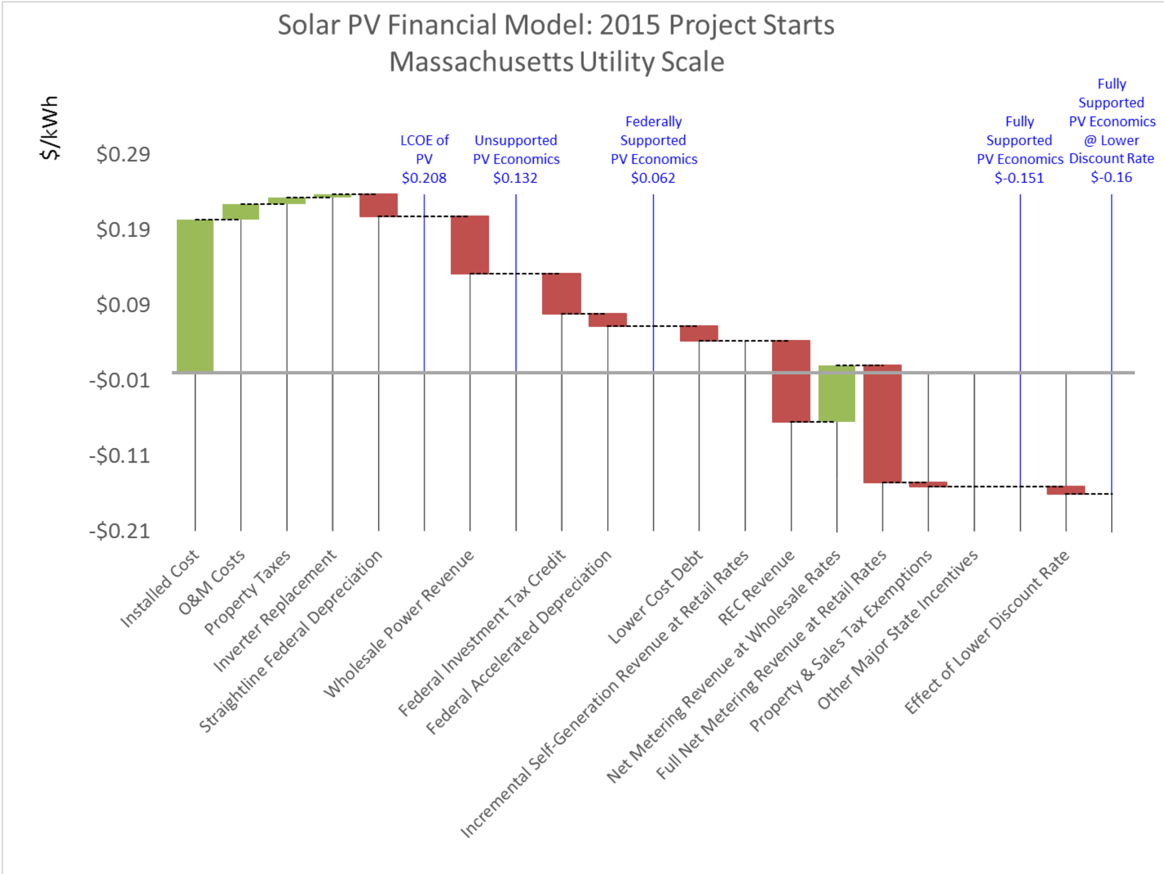


Exhibit A-10: New Hampshire Residential PV Drivers, 2015 Project Starts

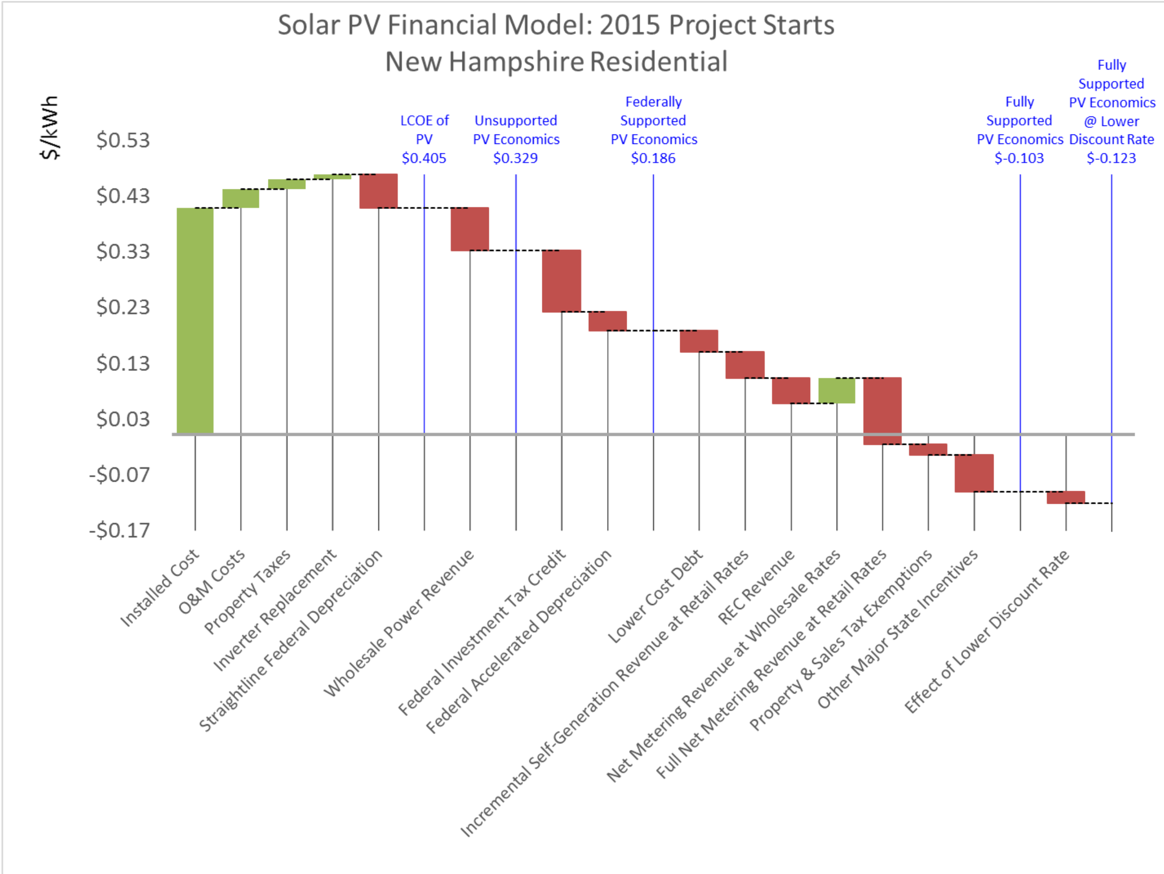


Exhibit A-11: New Hampshire Commercial PV Drivers, 2015 Project Starts

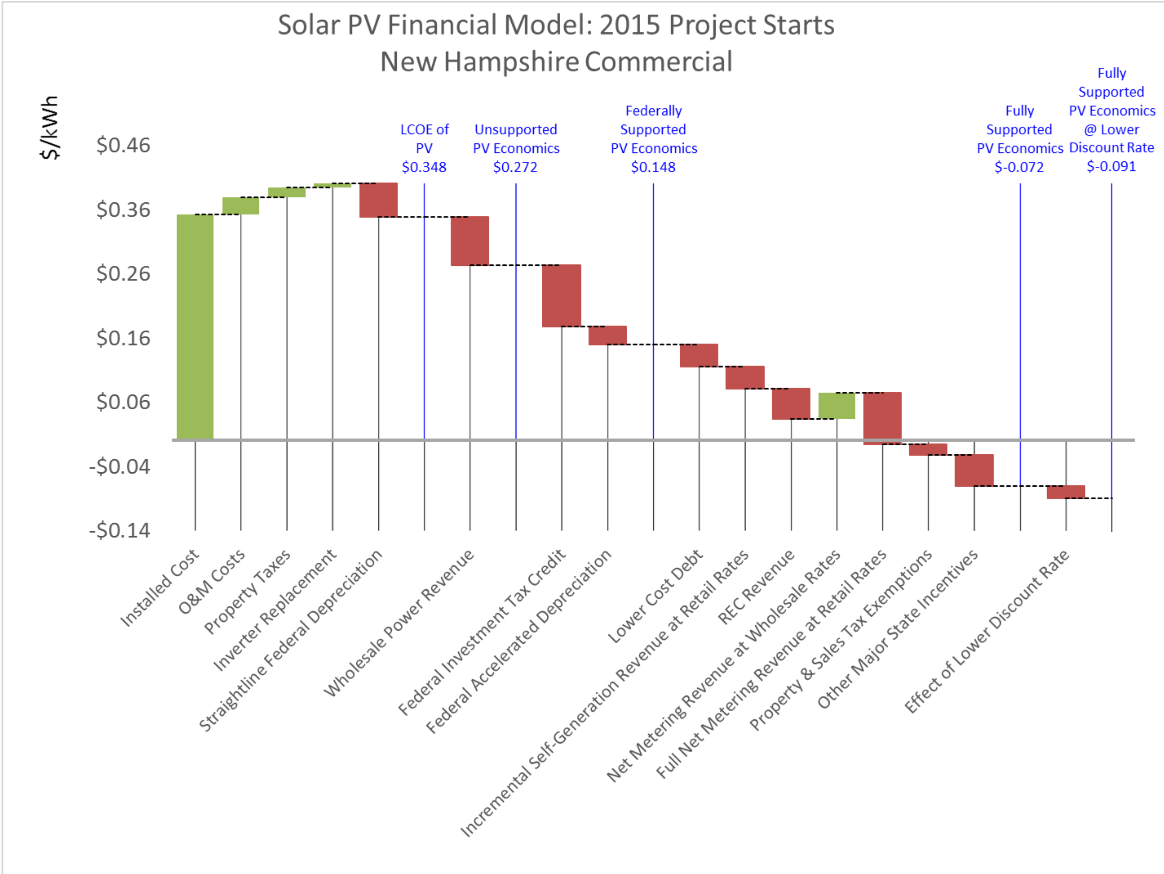


Exhibit A-12: New Hampshire Utility Scale PV Drivers, 2015 Project Starts

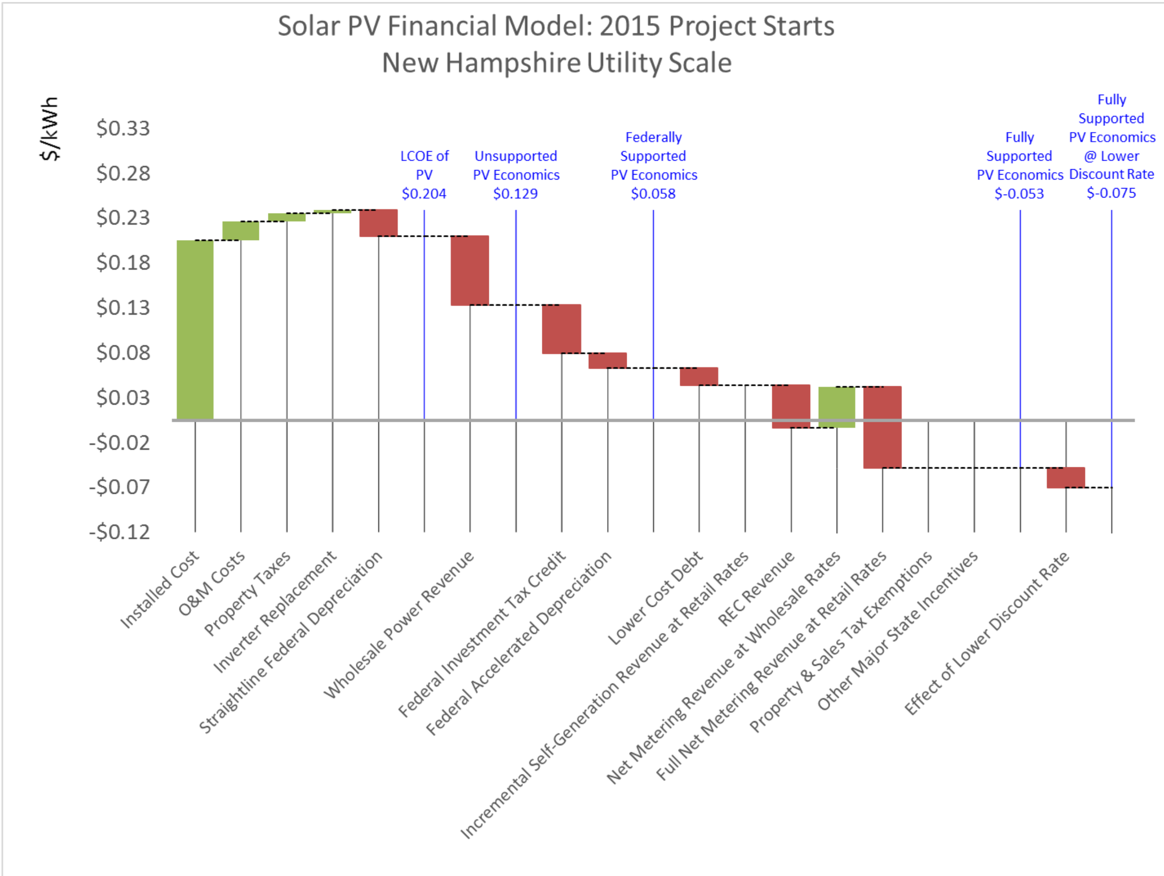


Exhibit A-13: Rhode Island Residential PV Drivers, 2015 Project Starts

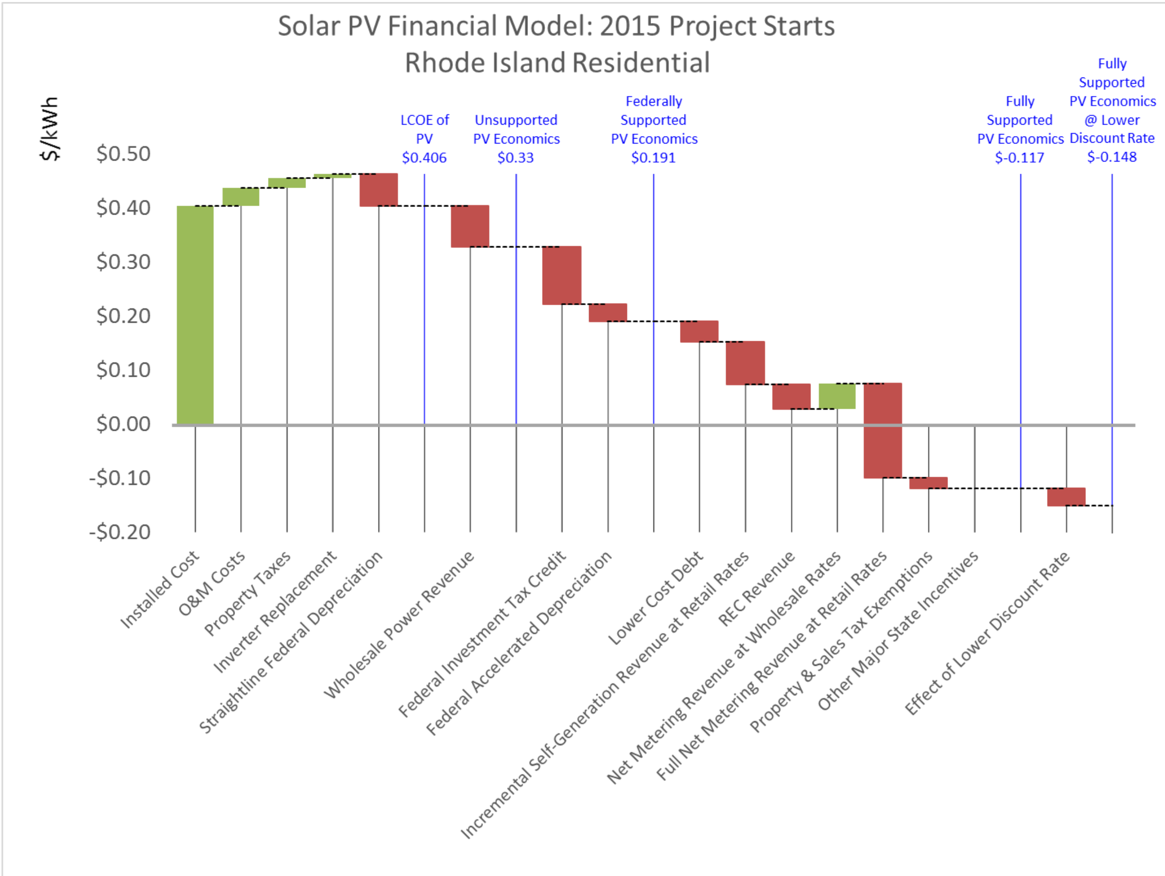


Exhibit A-14: Rhode Island Commercial PV Drivers, 2015 Project Starts

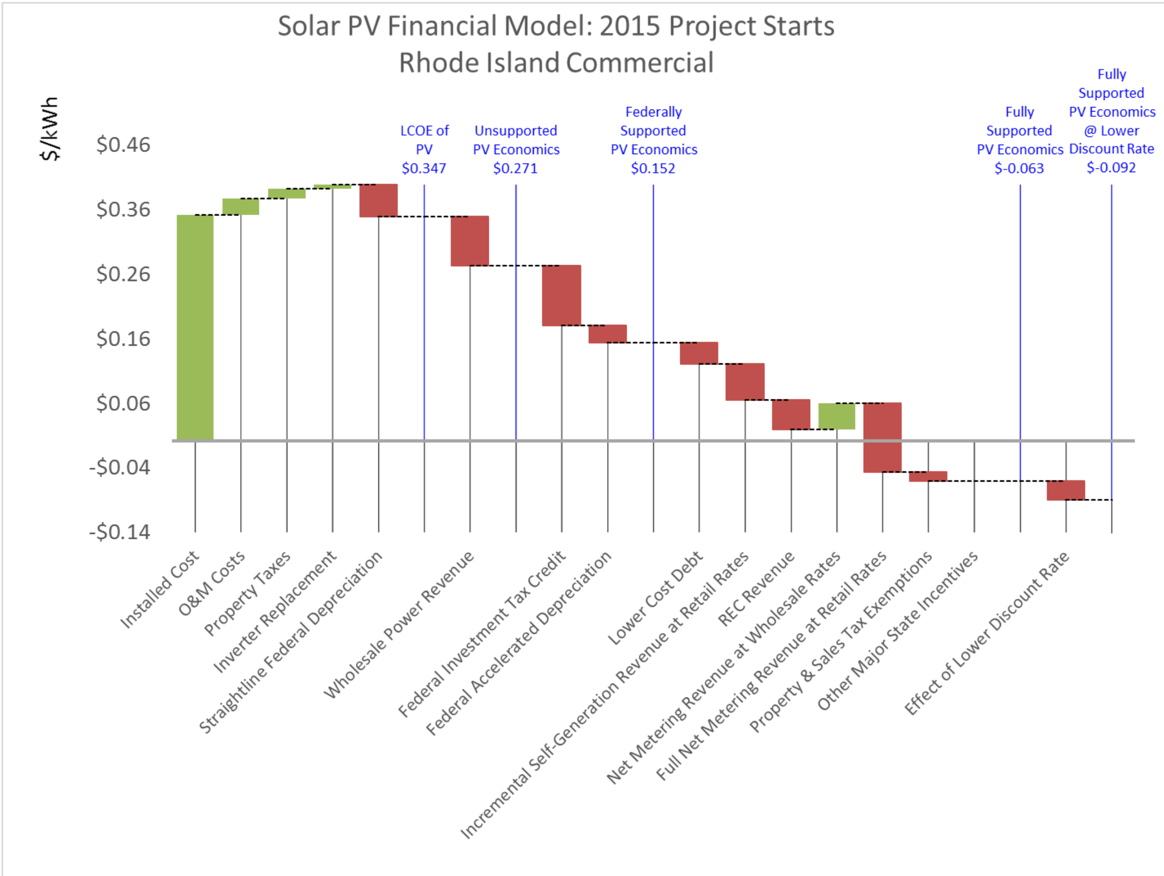


Exhibit A-15: Rhode Island Utility Scale PV Drivers, 2015 Project Starts

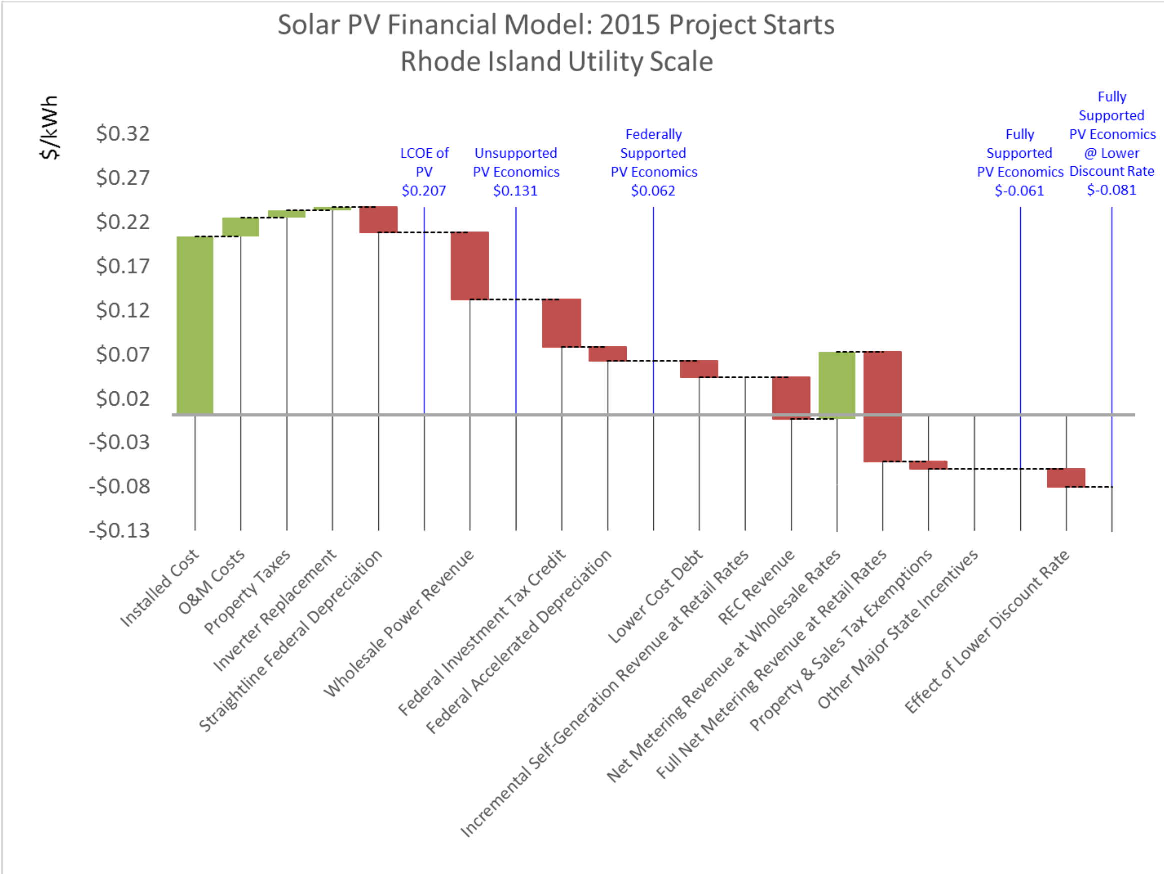


Exhibit A-16: Vermont Residential PV Drivers, 2015 Project Starts

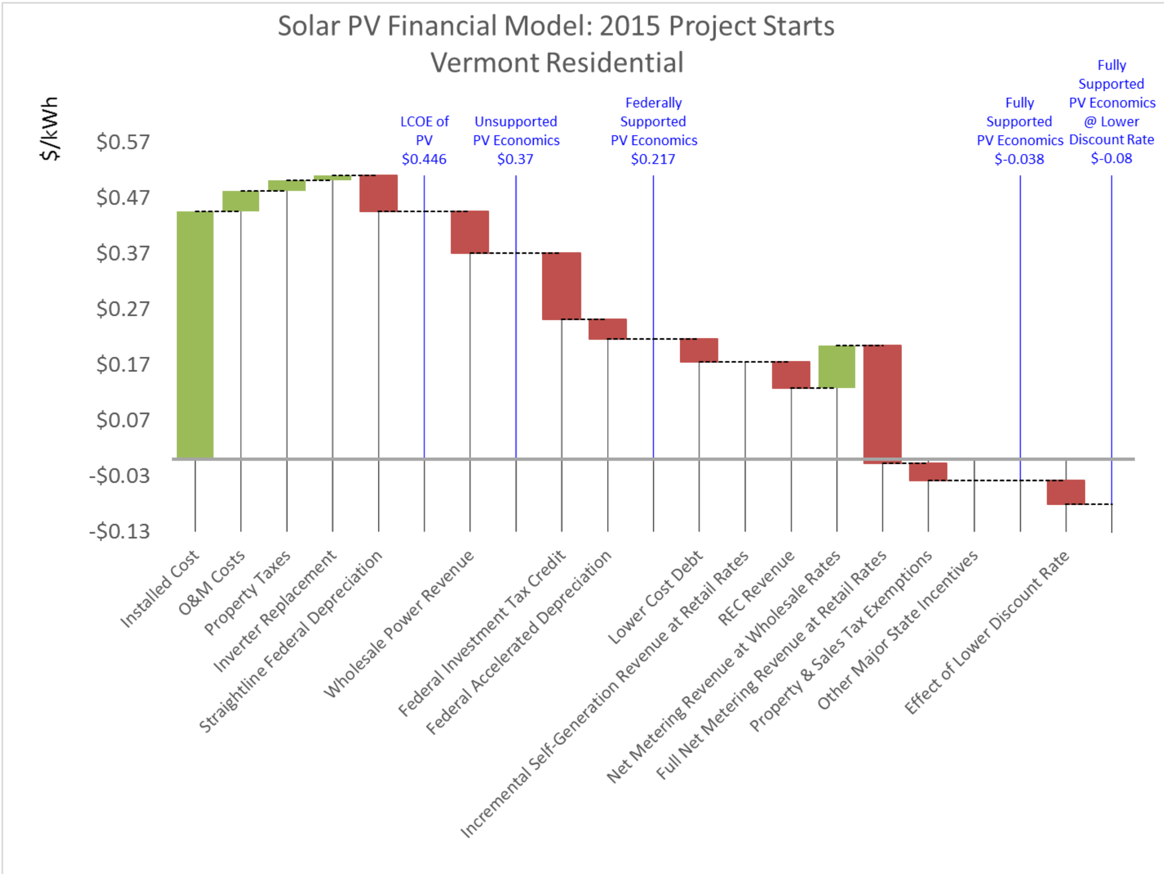


Exhibit A-17: Vermont Commercial PV Drivers, 2015 Project Starts

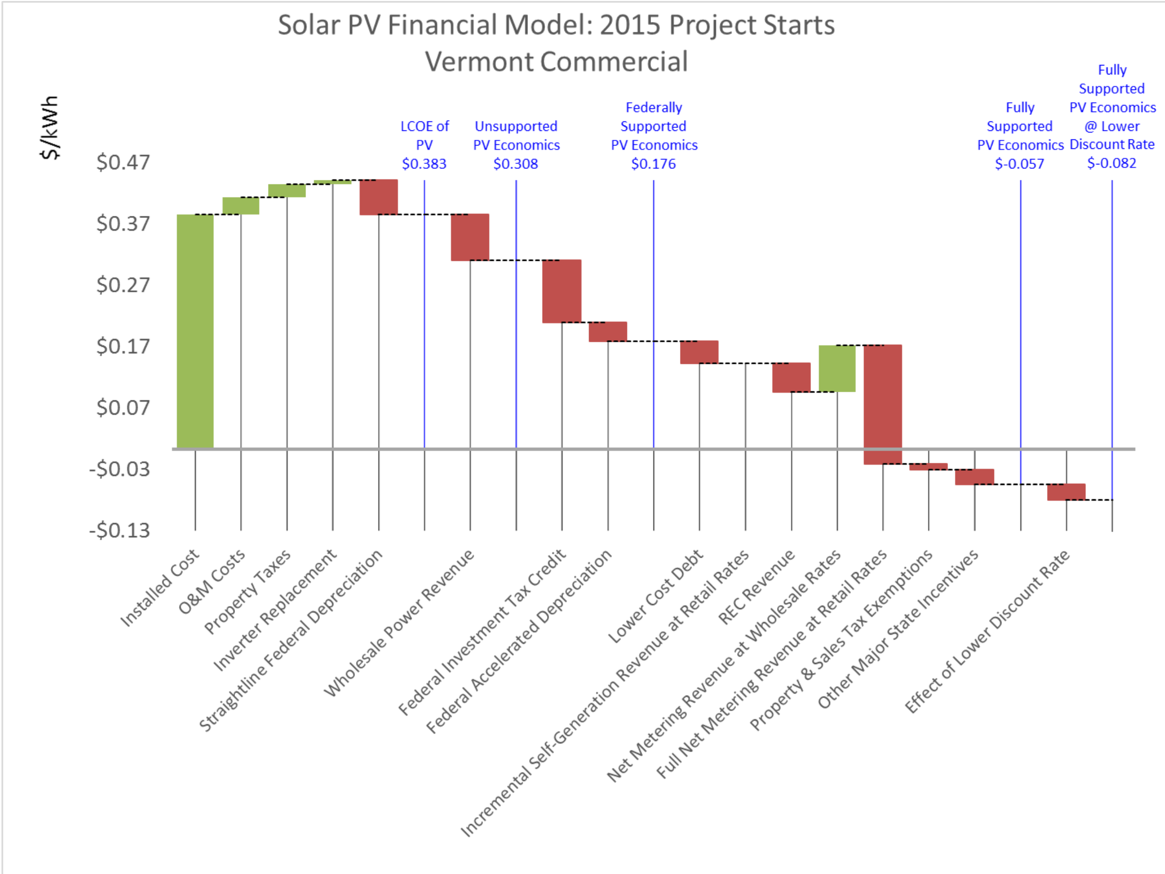
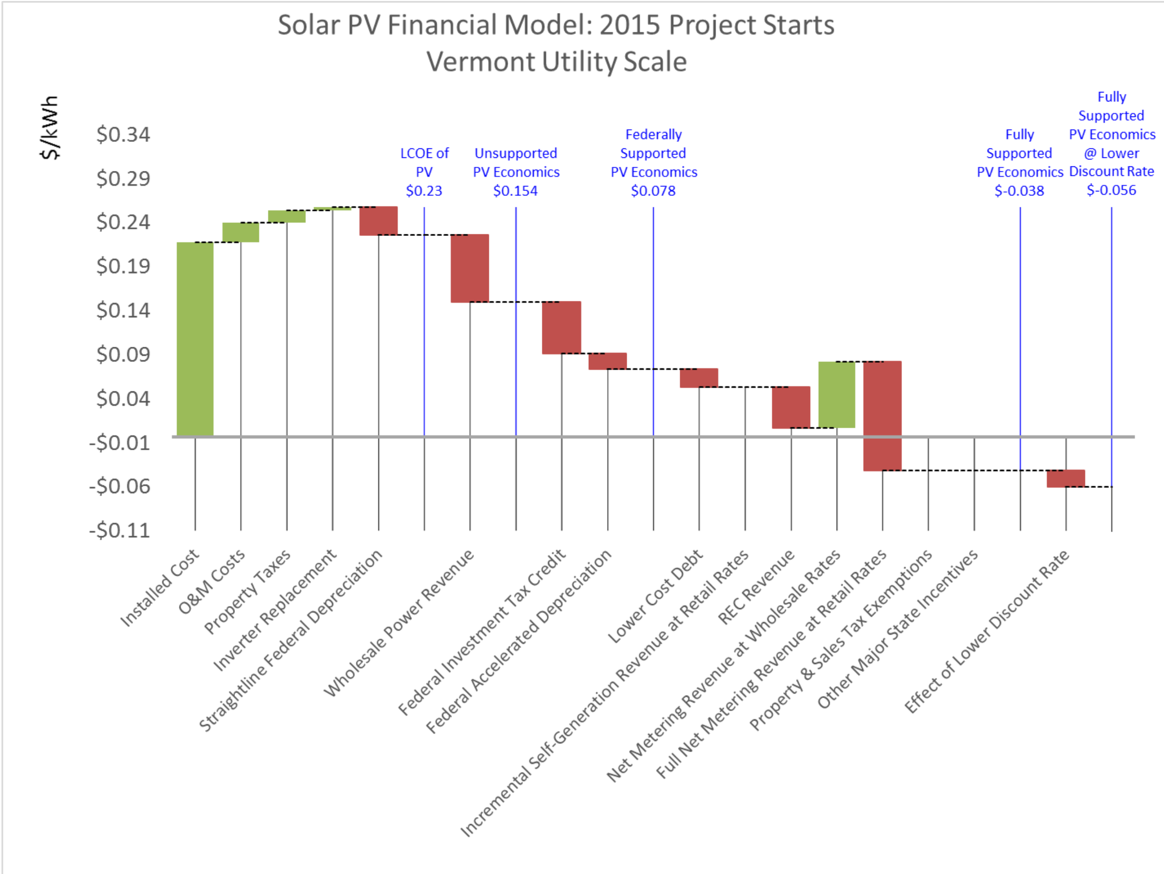


Exhibit A-18: Vermont Utility Scale PV Drivers, 2015 Project Starts



Appendix B: Waterfall Charts for 2019 Project Starts

Exhibit B-1: Connecticut Residential PV Drivers, 2019 Project Starts

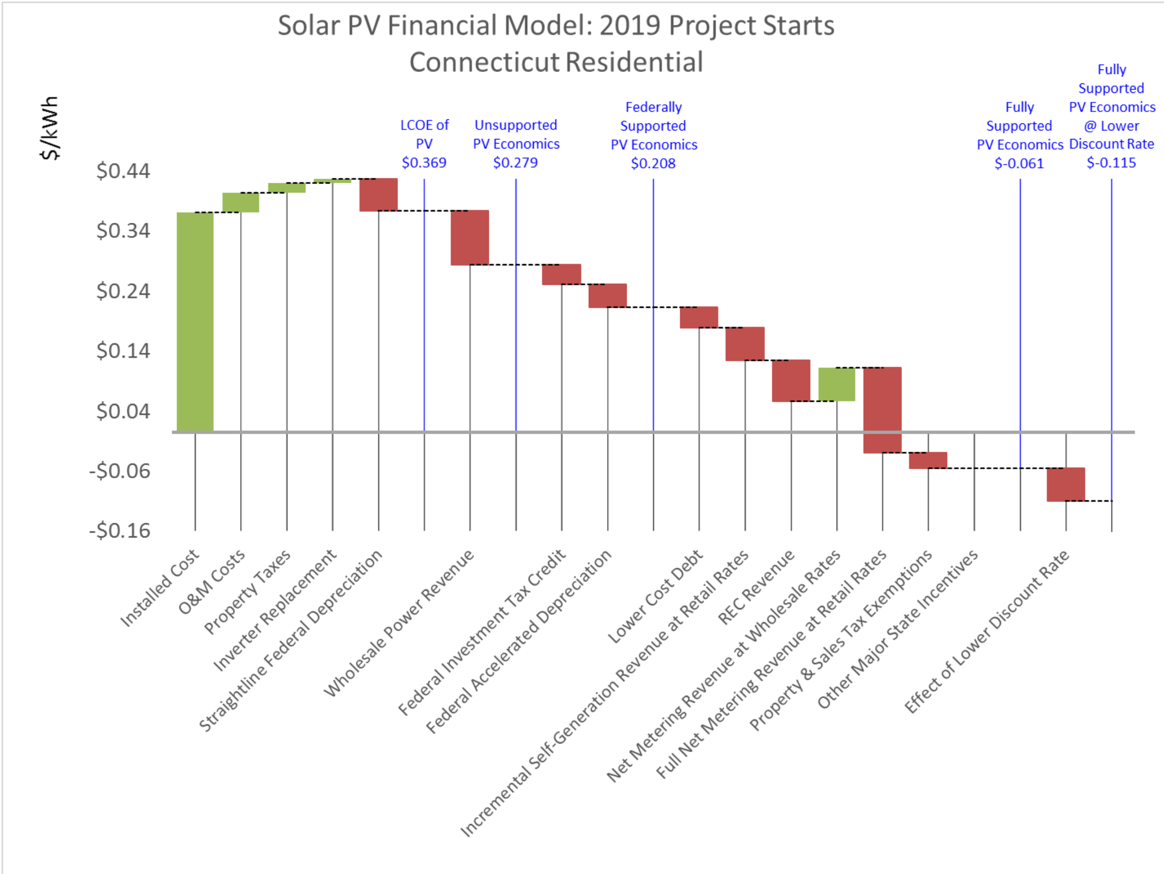


Exhibit B-2: Connecticut Commercial PV Drivers, 2019 Project Starts

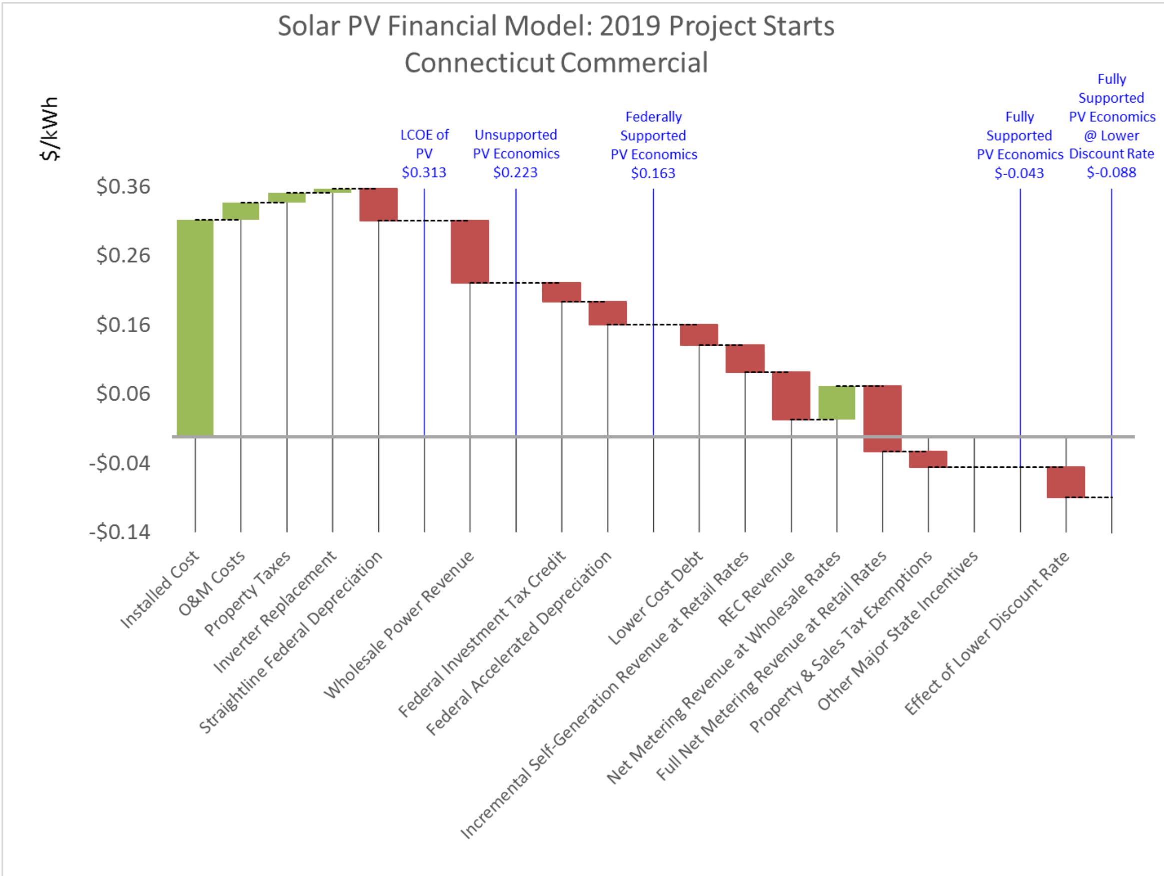


Exhibit B-3: Connecticut Utility Scale PV Drivers, 2019 Project Starts

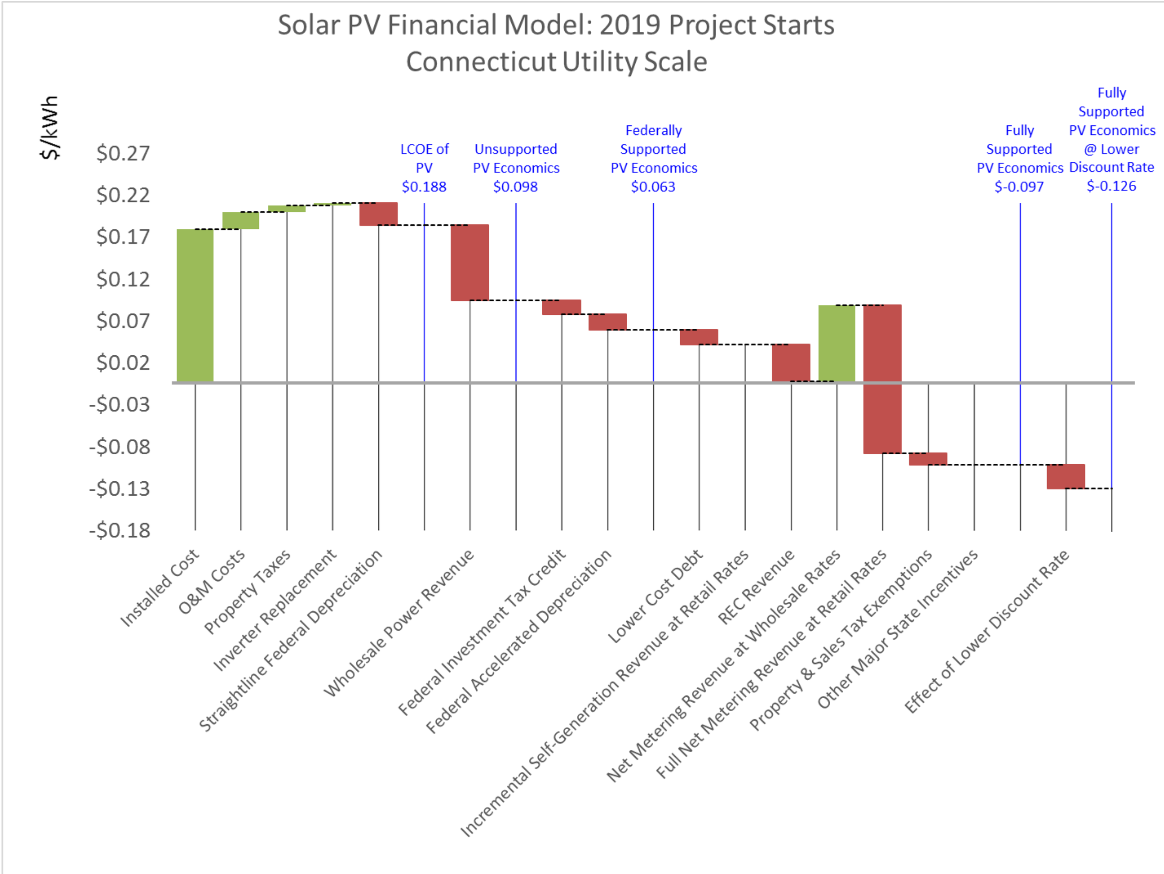


Exhibit B-4: Maine Residential PV Drivers, 2019 Project Starts

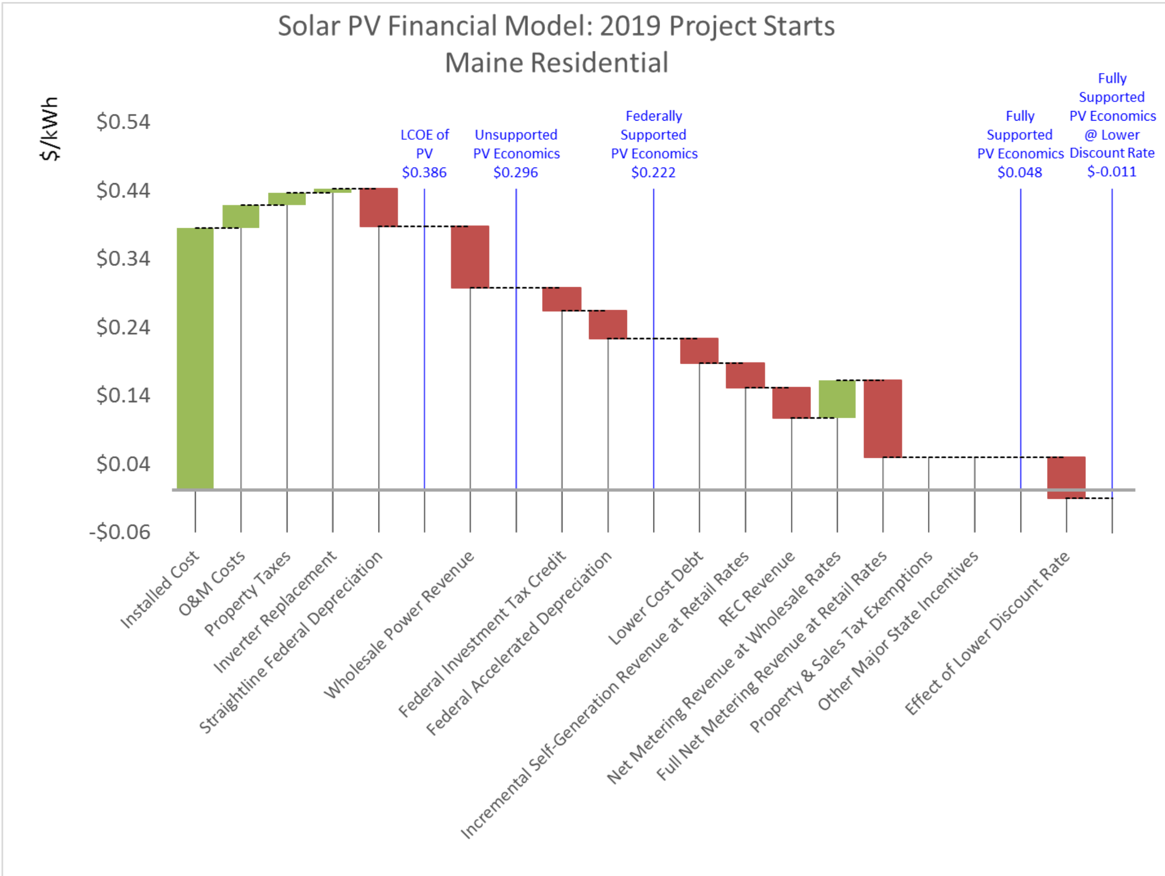


Exhibit B-5: Maine Commercial PV Drivers, 2019 Project Starts

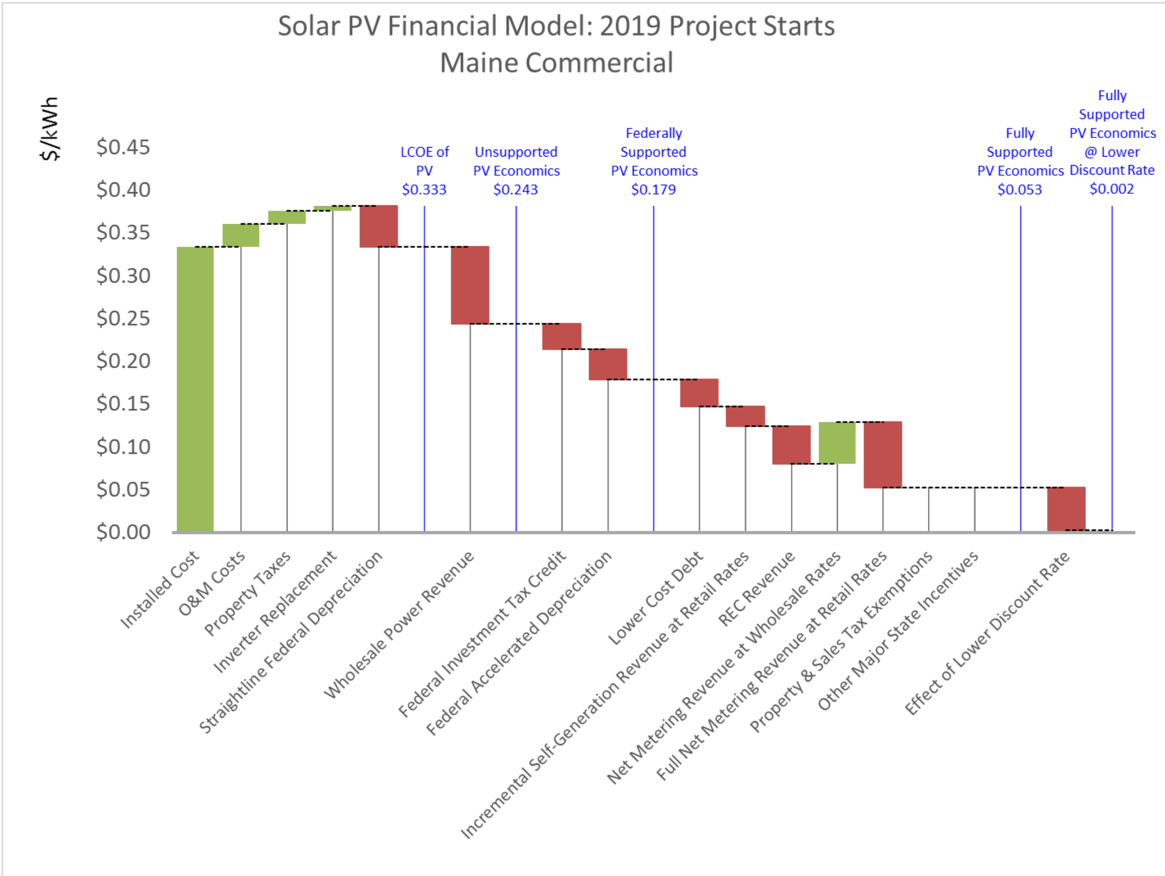


Exhibit B-6: Maine Utility Scale PV Drivers, 2019 Project Starts

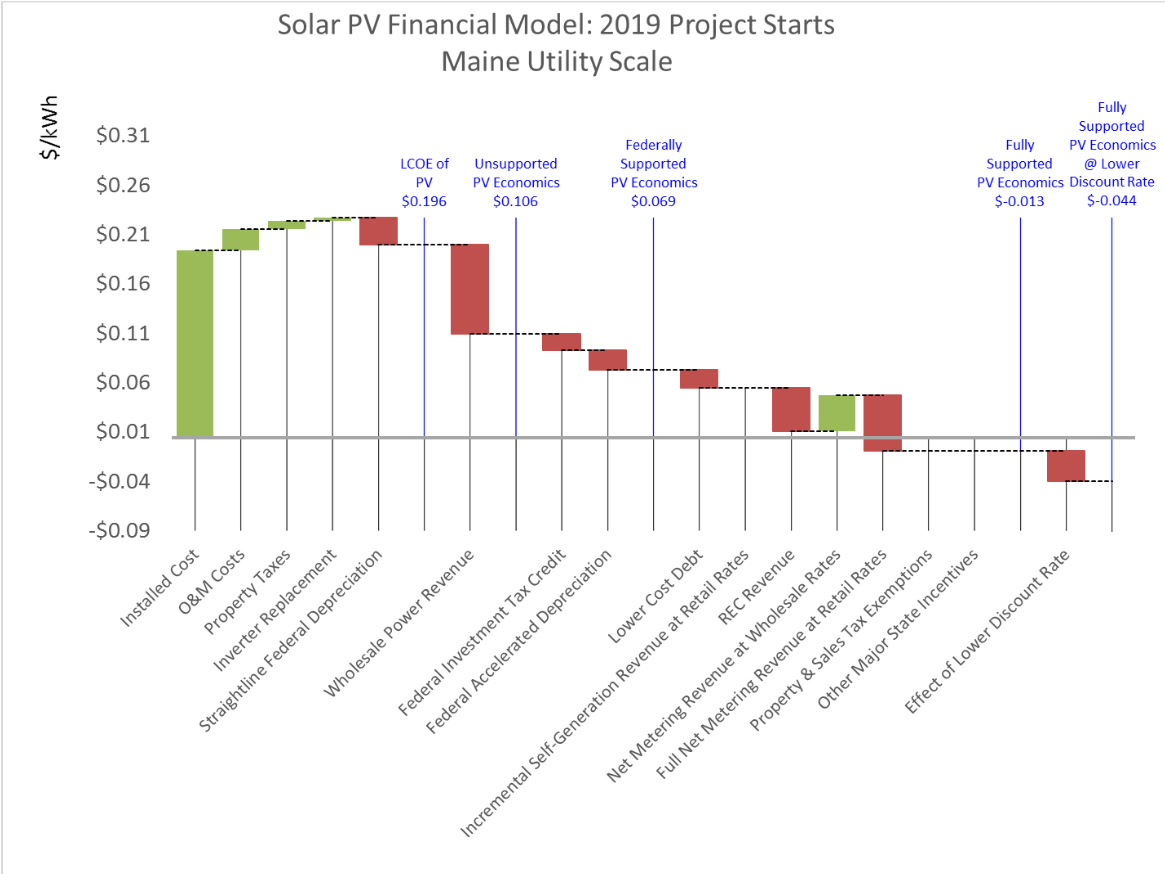


Exhibit B-7: Massachusetts Residential PV Drivers, 2019 Project Starts

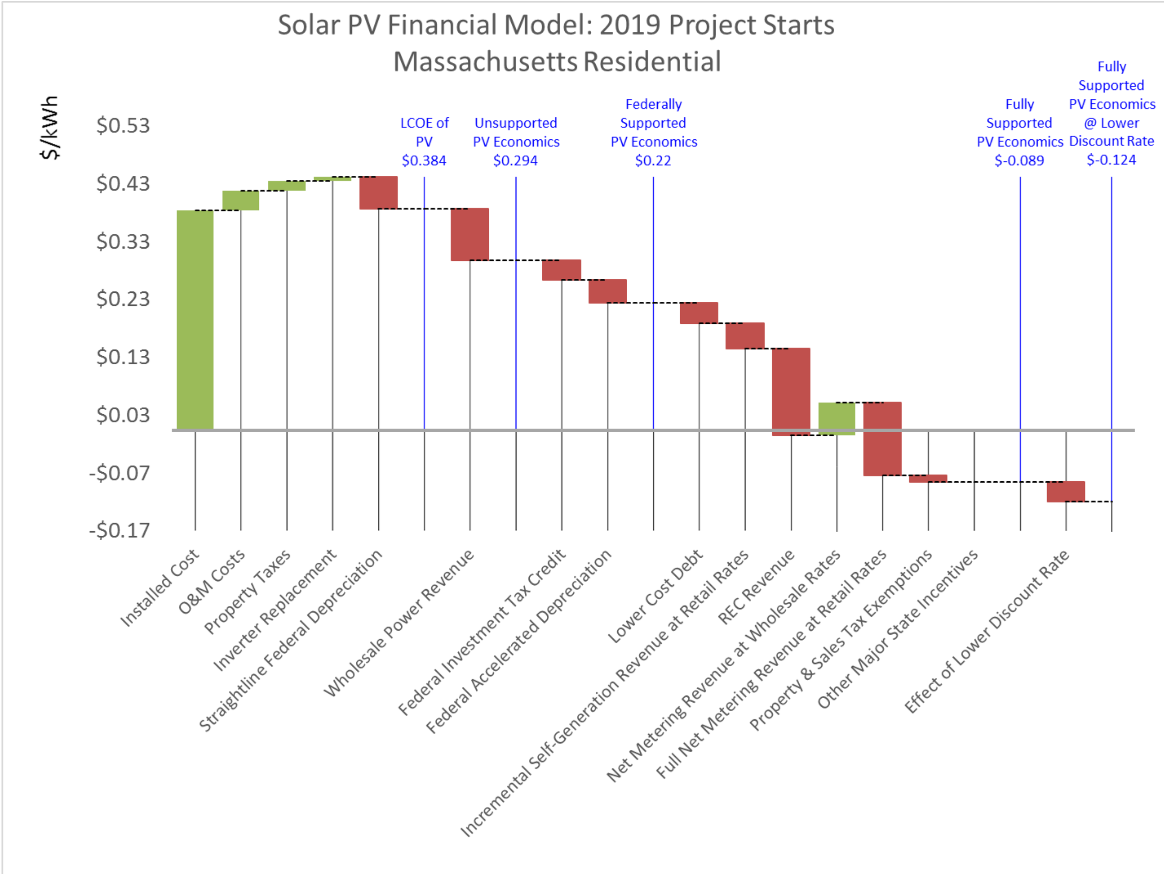


Exhibit B-8: Massachusetts Commercial PV Drivers, 2019 Project Starts

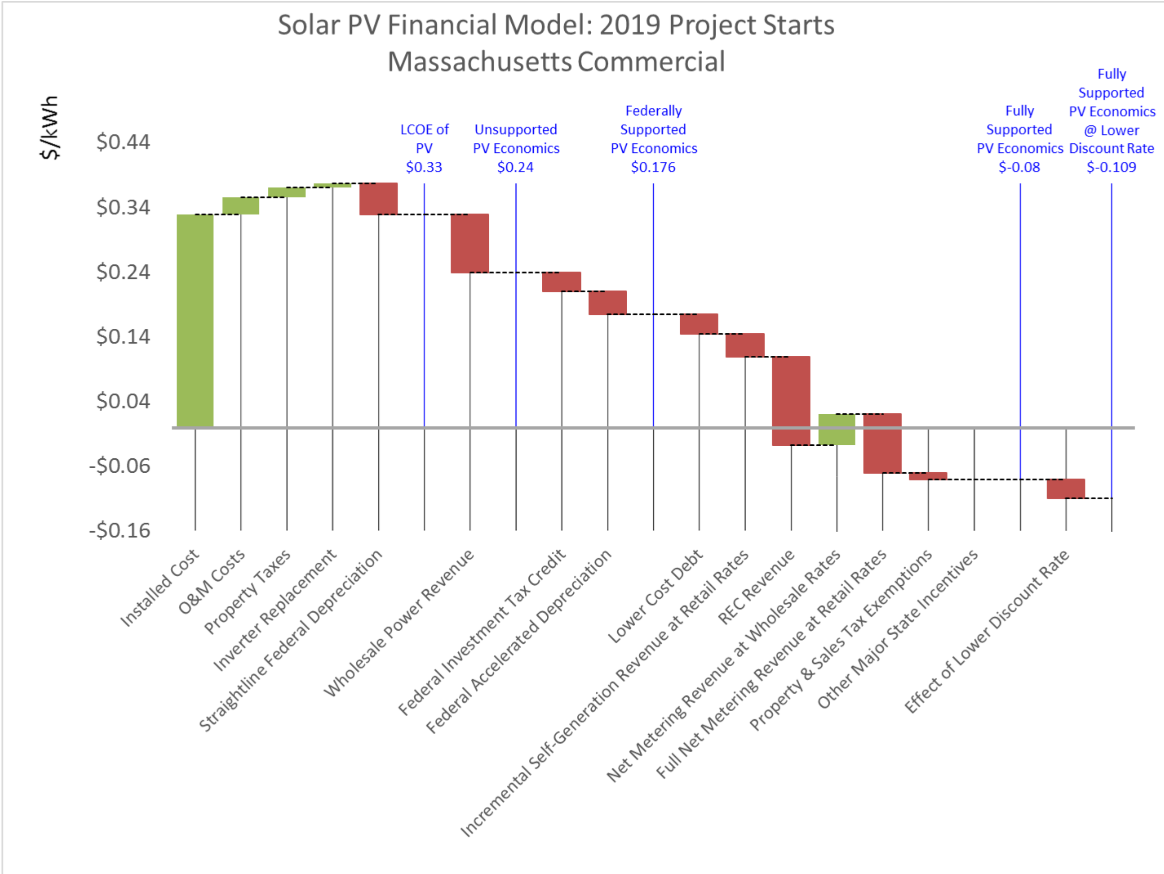


Exhibit B-9: Massachusetts Utility Scale PV Drivers, 2019 Project Starts

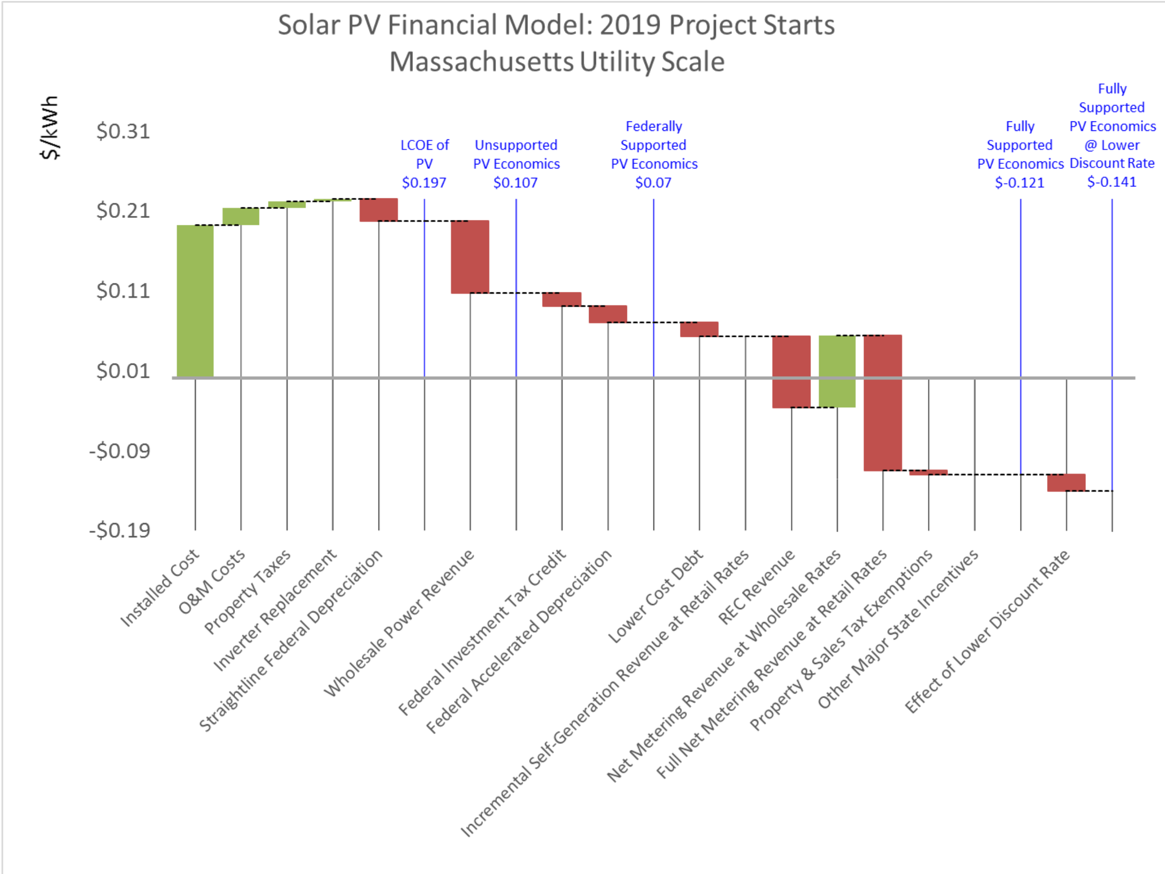


Exhibit B-10: New Hampshire Residential PV Drivers, 2019 Project Starts

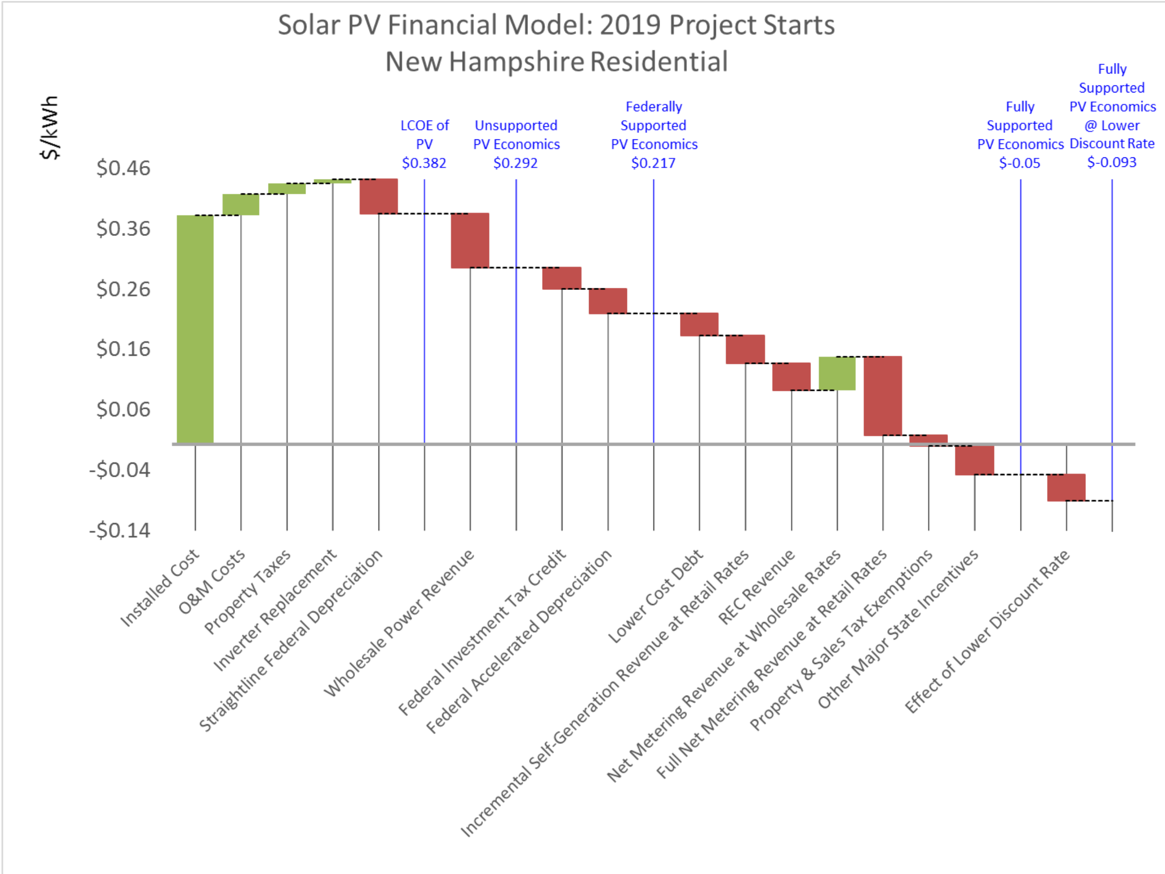


Exhibit B-11: New Hampshire Commercial PV Drivers, 2019 Project Starts

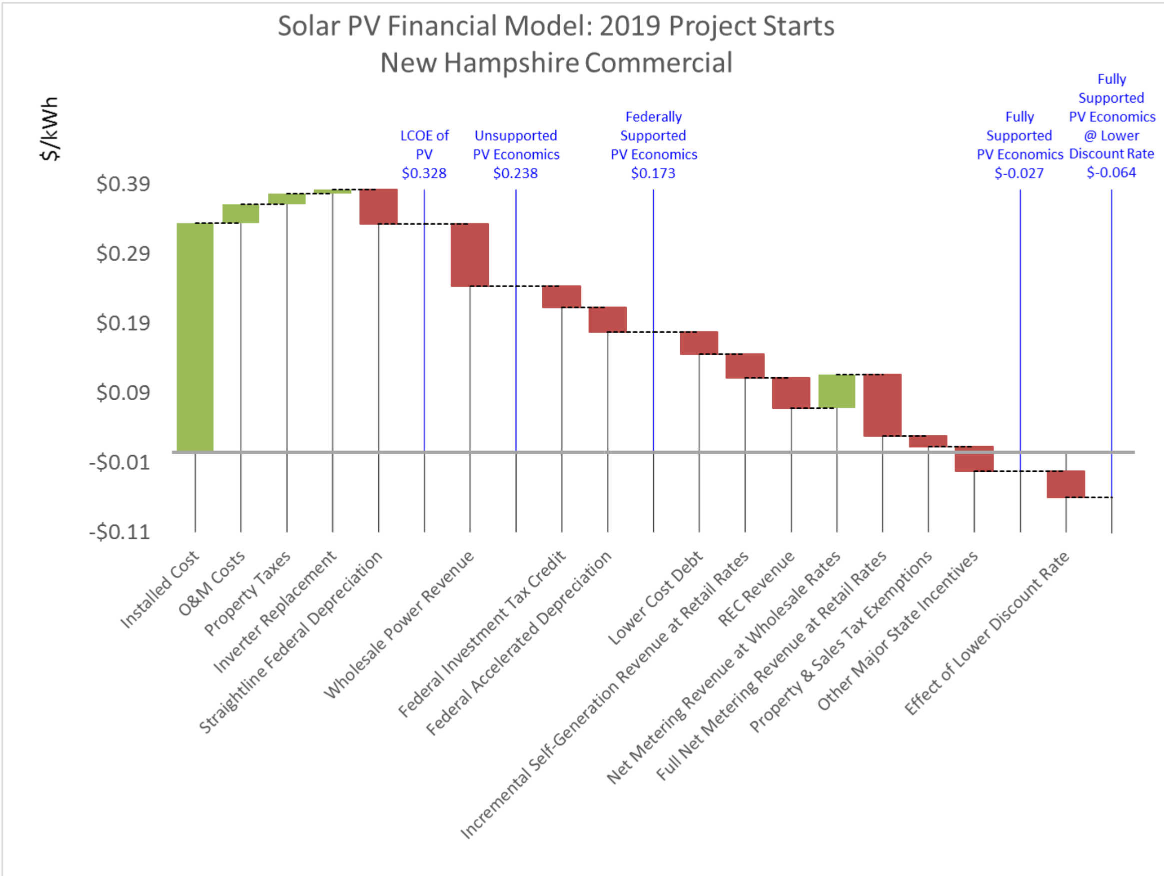


Exhibit B-12: New Hampshire Utility Scale PV Drivers, 2019 Project Starts

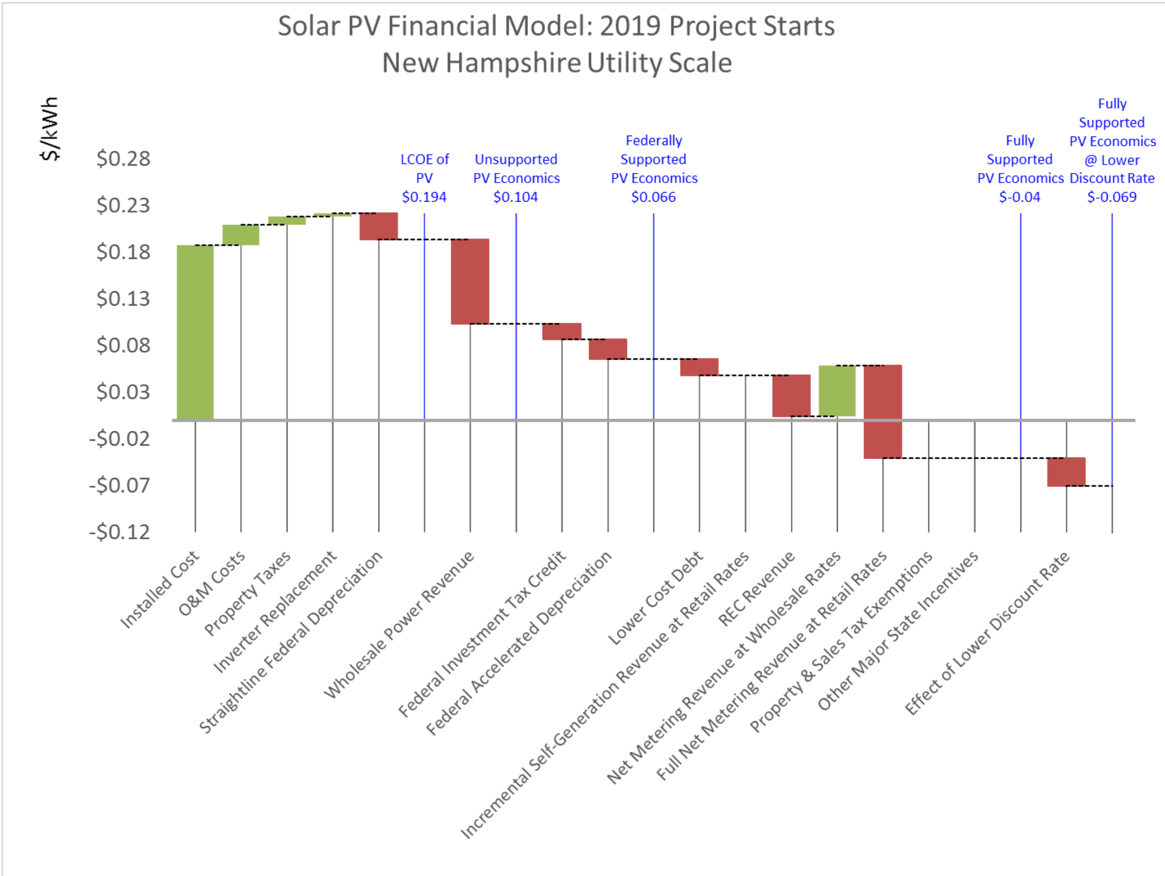


Exhibit B-13: Rhode Island Residential PV Drivers, 2019 Project Starts

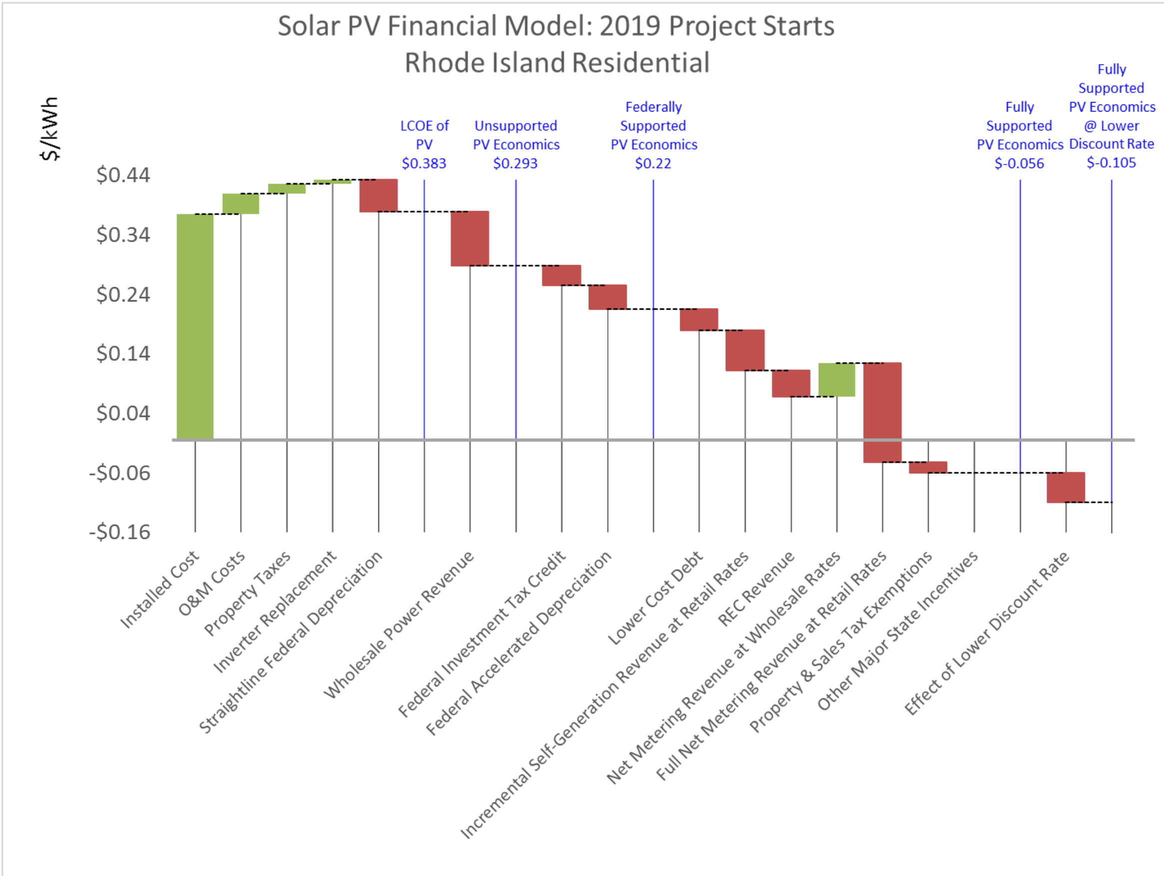


Exhibit B-14: Rhode Island Commercial PV Drivers, 2019 Project Starts

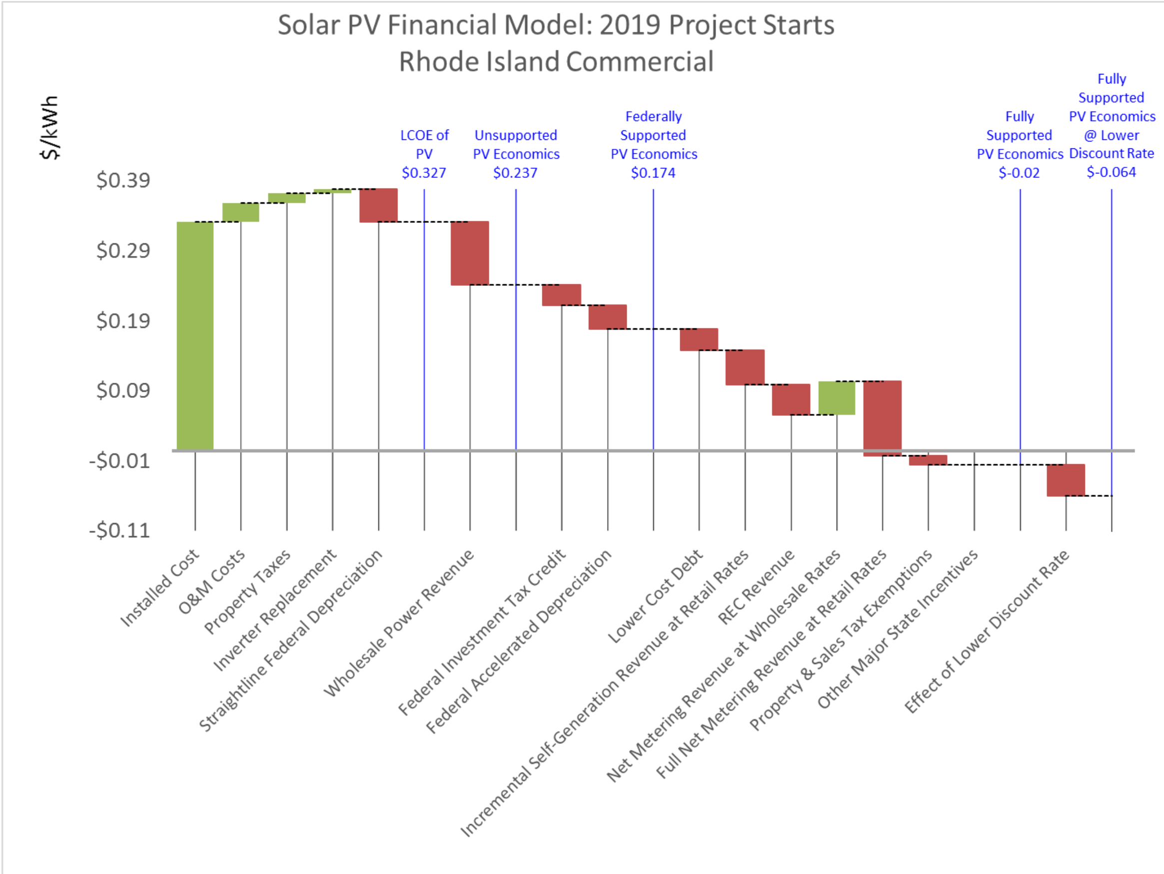


Exhibit B-15: Rhode Island Utility Scale PV Drivers, 2019 Project Starts

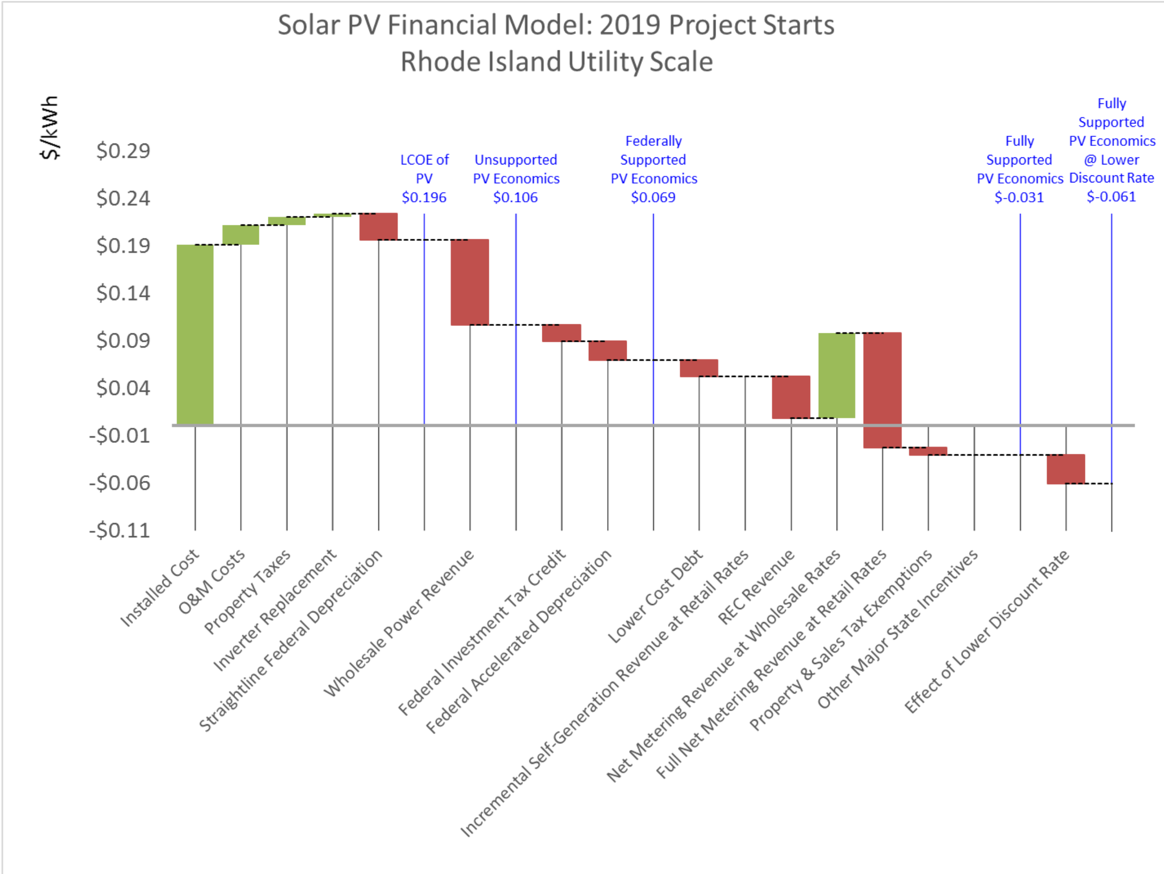


Exhibit B-16: Vermont Residential PV Drivers, 2019 Project Starts

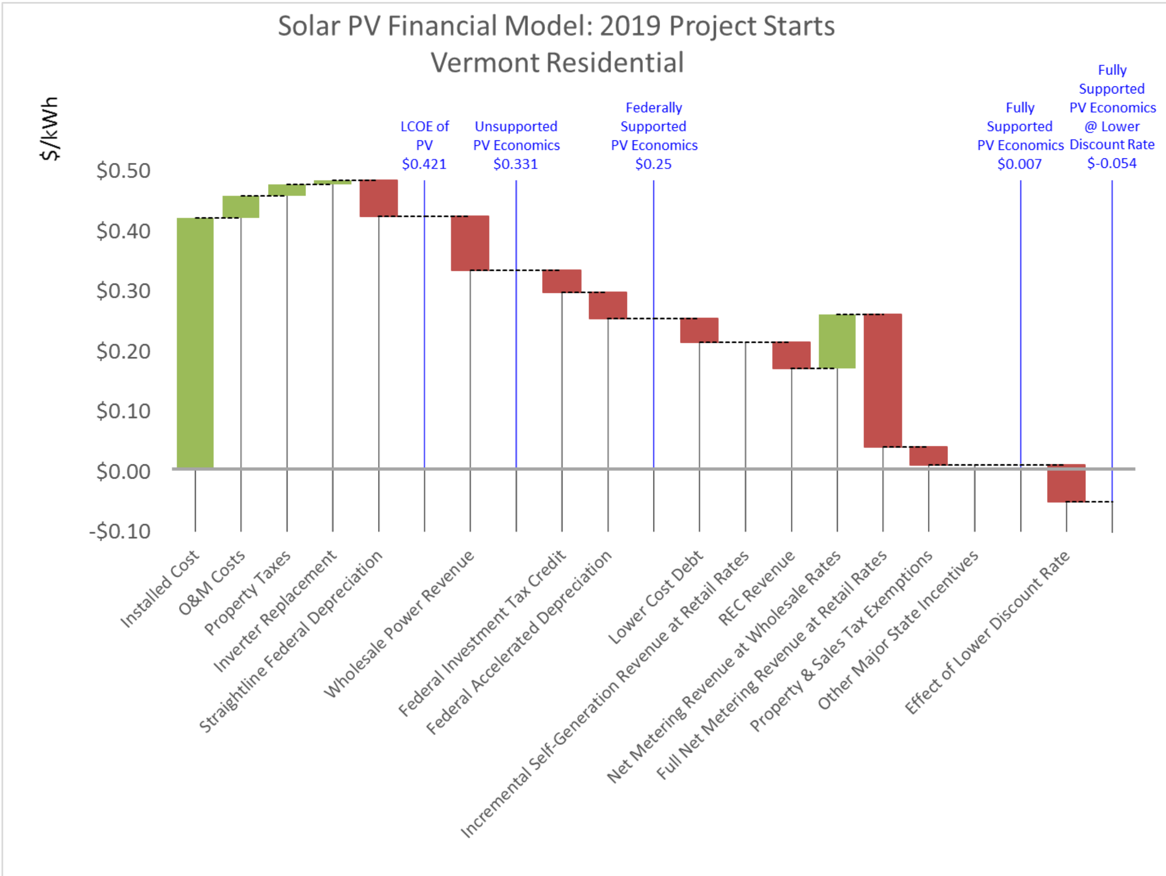


Exhibit B-17: Vermont Commercial PV Drivers, 2019 Project Starts

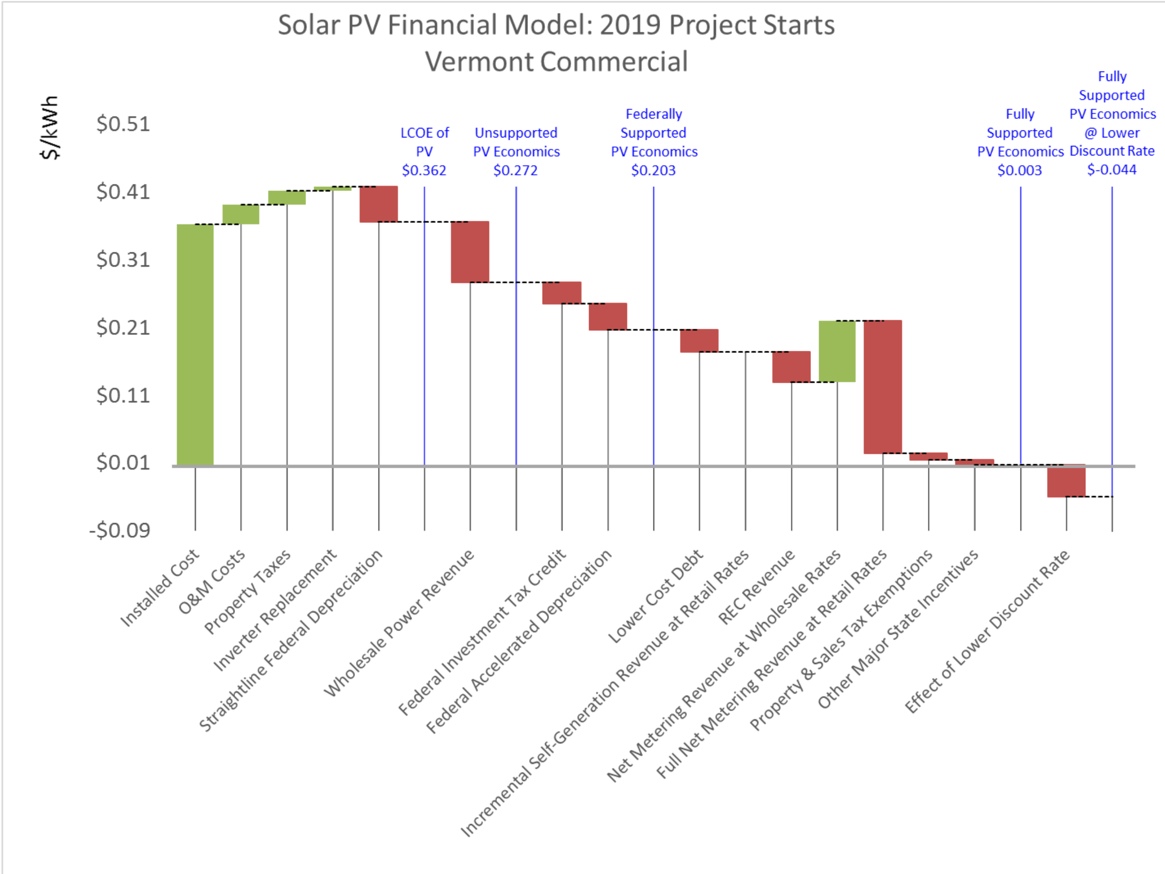
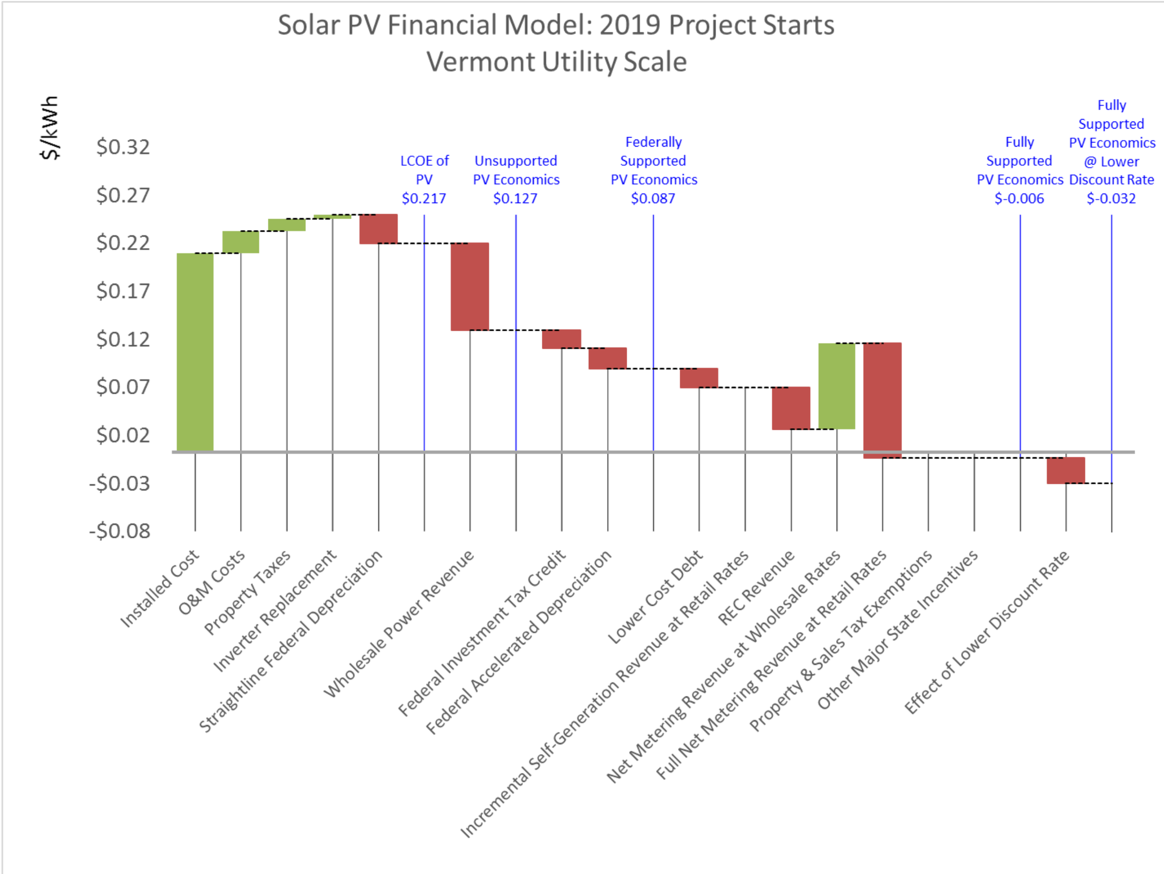


Exhibit B-18: Vermont Utility Scale PV Drivers, 2019 Project Starts



Appendix C: Waterfall Charts for 2024 Project Starts

Appendix C: Waterfall Charts for 2024 Project Starts

Exhibit C-1: Connecticut Residential PV Drivers, 2024 Project Starts

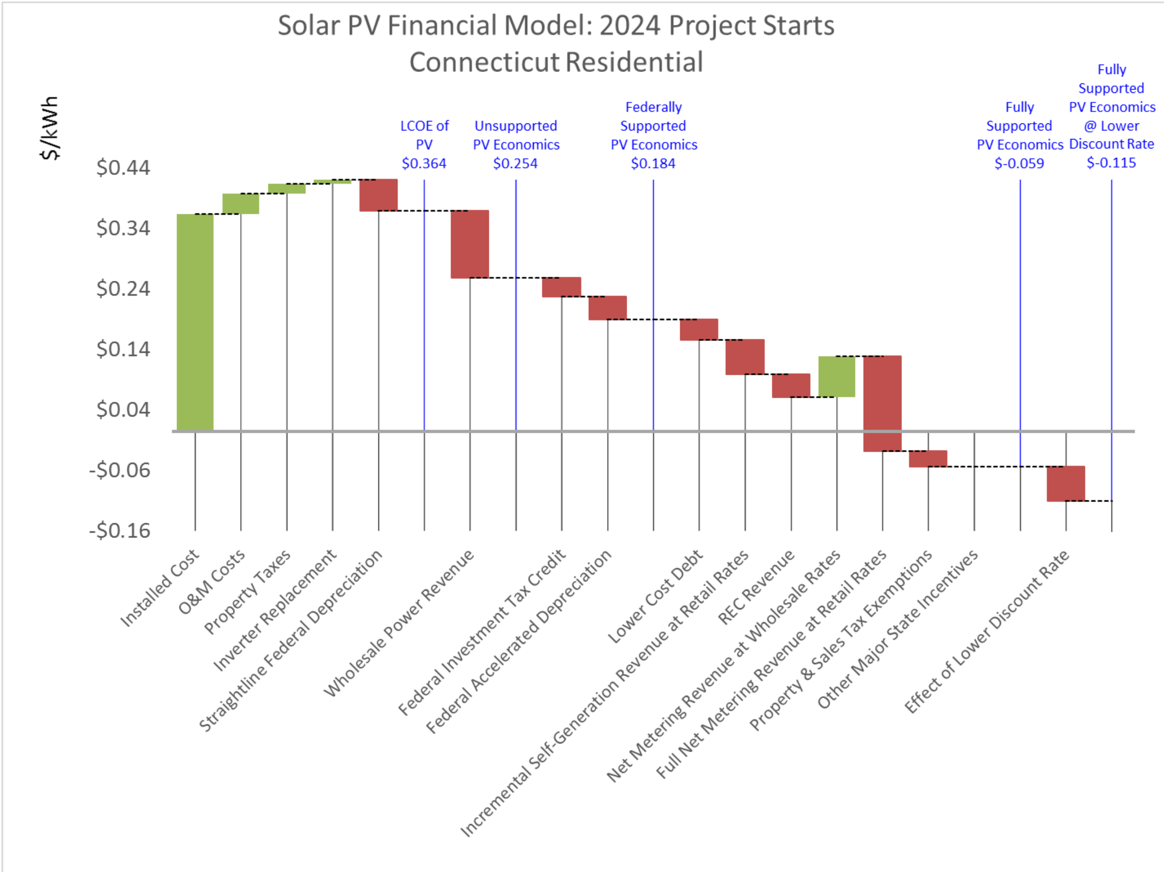


Exhibit C-2: Connecticut Commercial PV Drivers, 2024 Project Starts

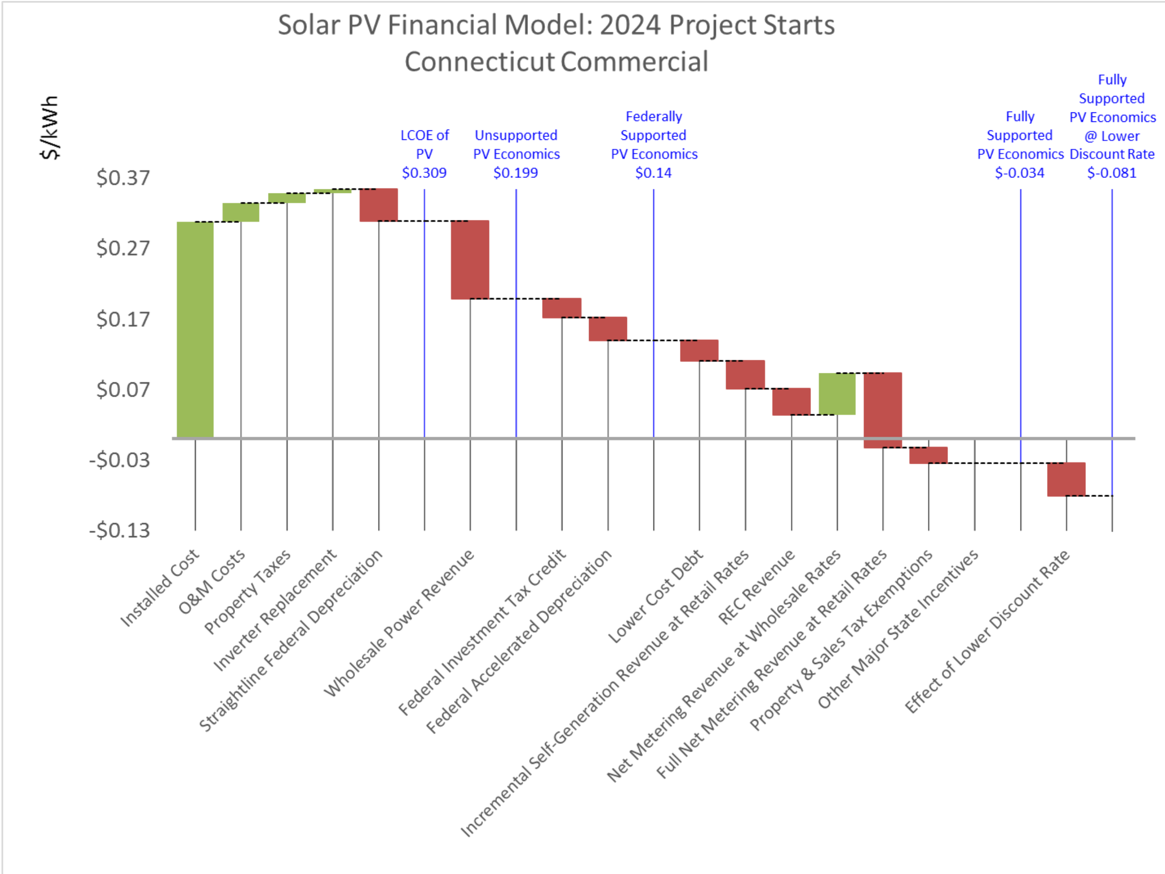
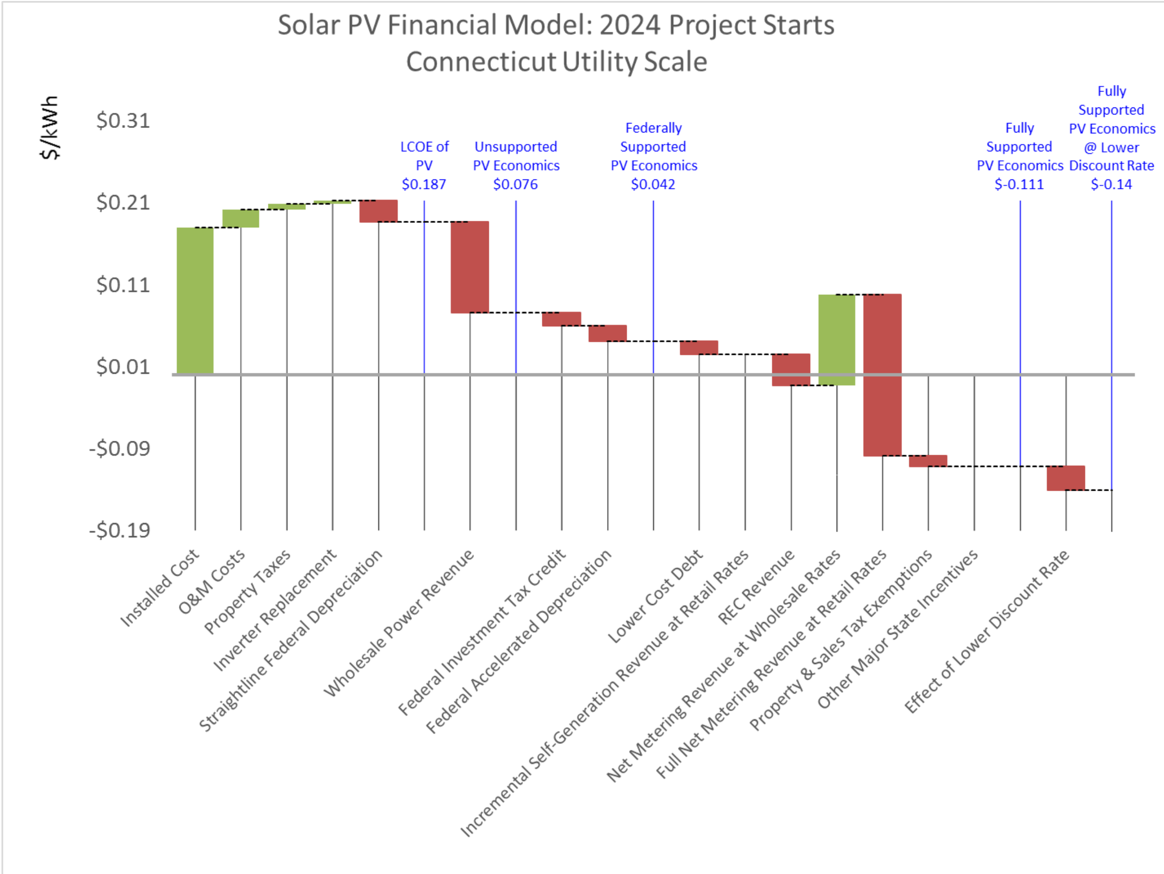


Exhibit C-3: Connecticut Utility Scale PV Drivers, 2024 Project Starts



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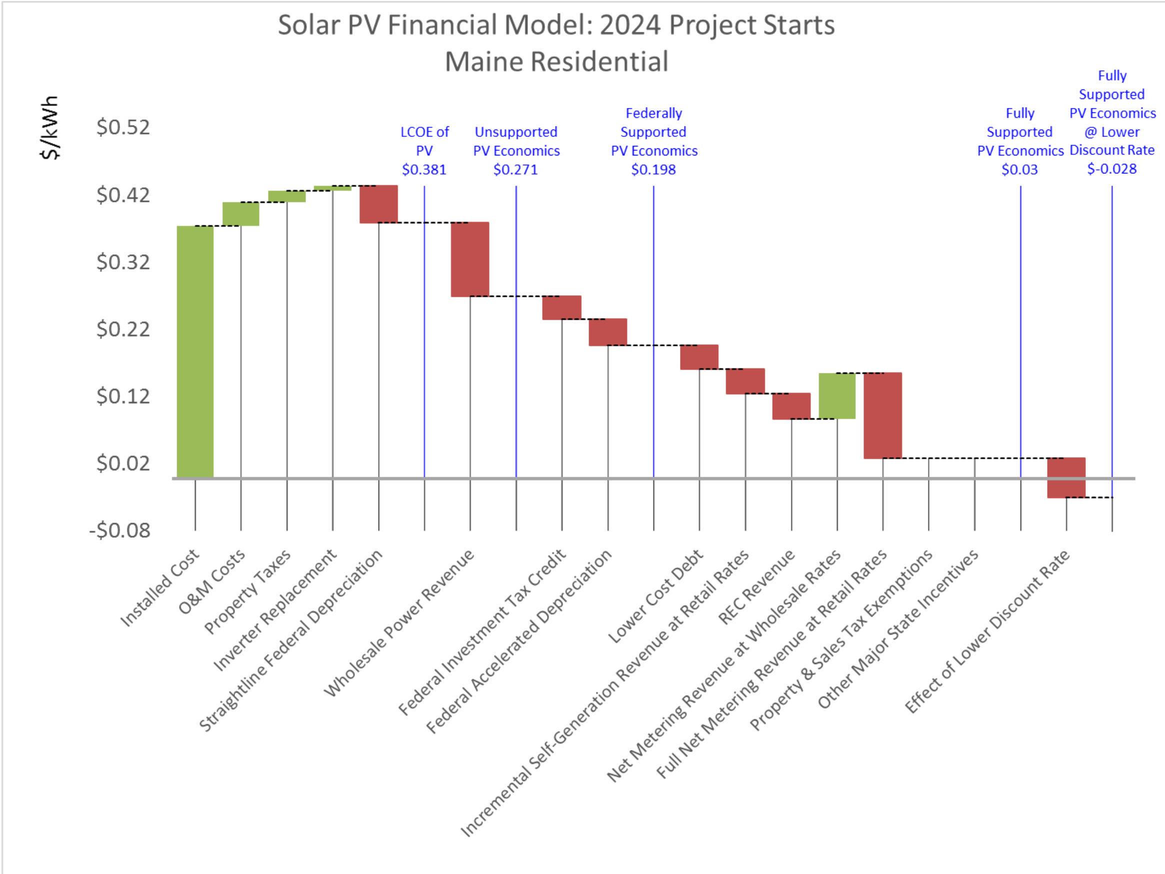


Exhibit C-5: Maine Commercial PV Drivers, 2024 Project Starts

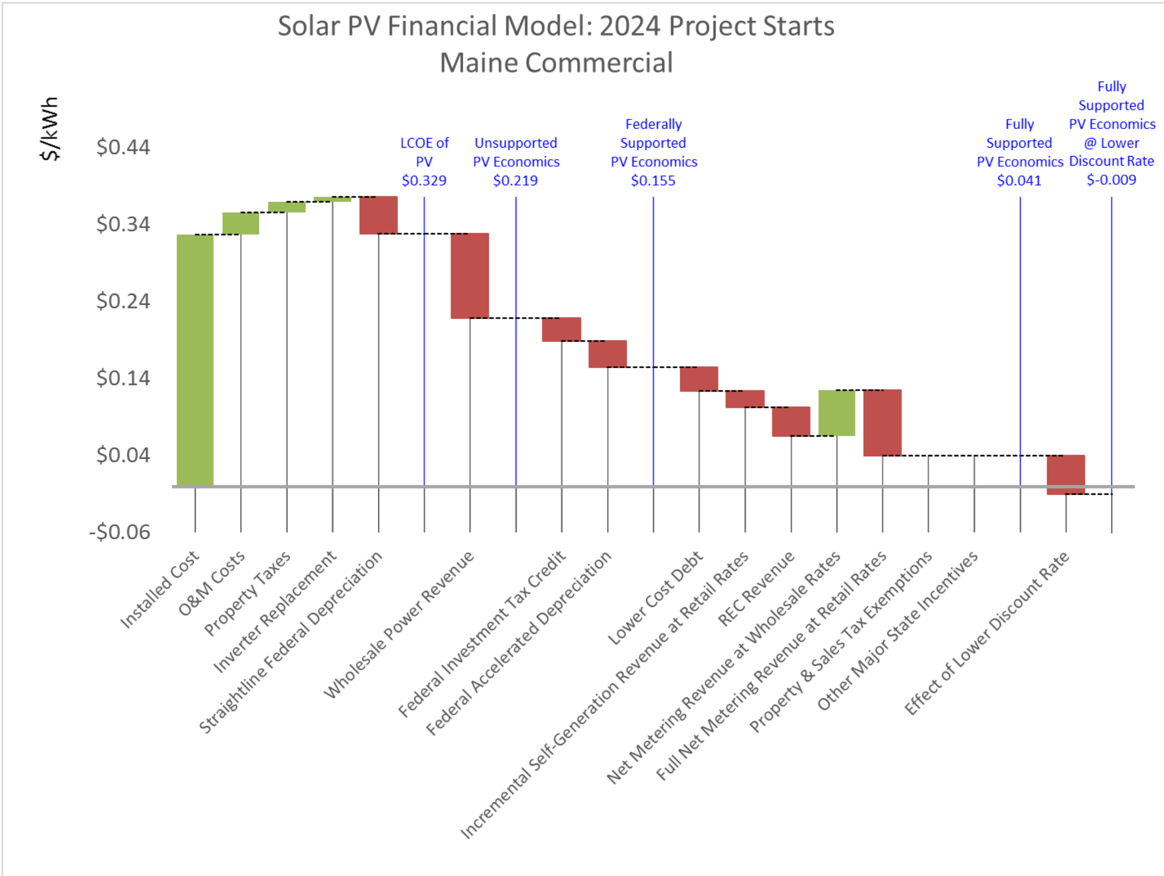


Exhibit C-6: Maine Utility Scale PV Drivers, 2024 Project Starts

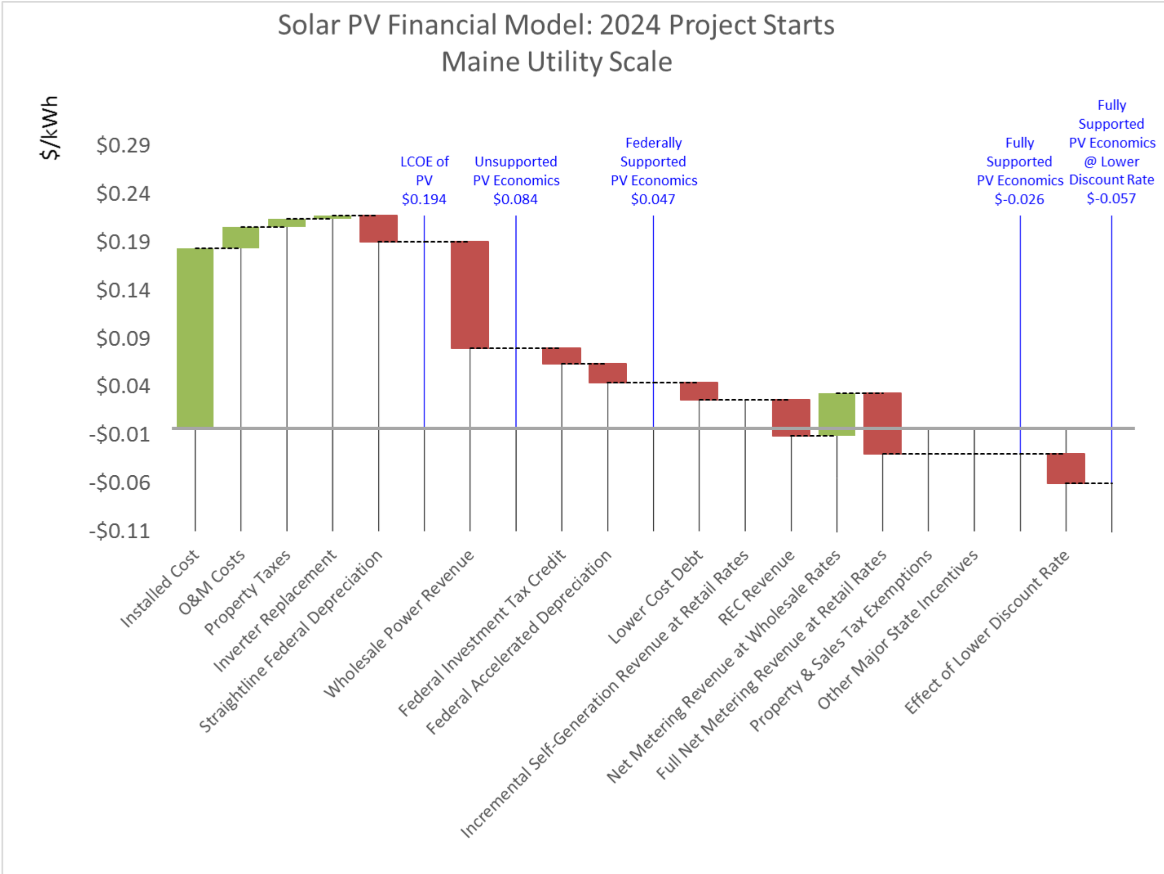


Exhibit C-7: Massachusetts Residential PV Drivers, 2024 Project Starts

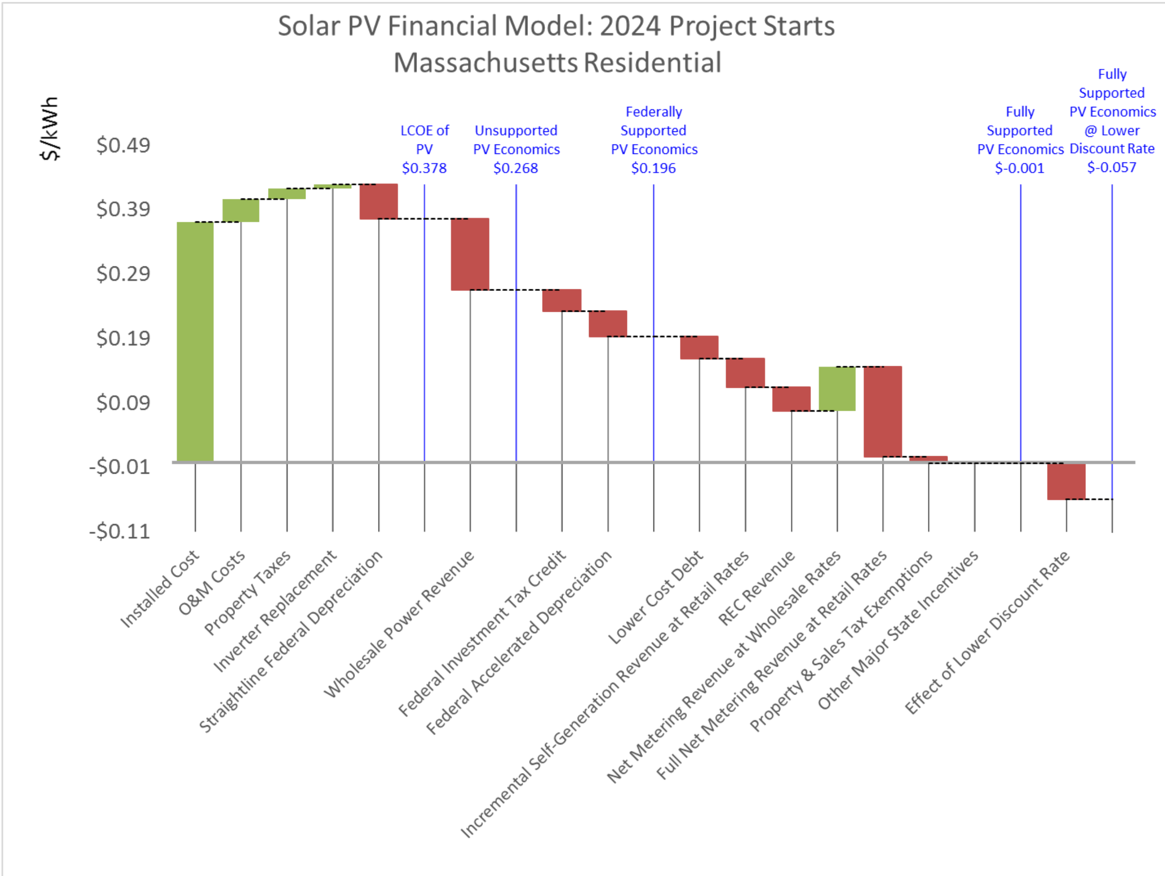


Exhibit C-8: Massachusetts Commercial PV Drivers, 2024 Project Starts

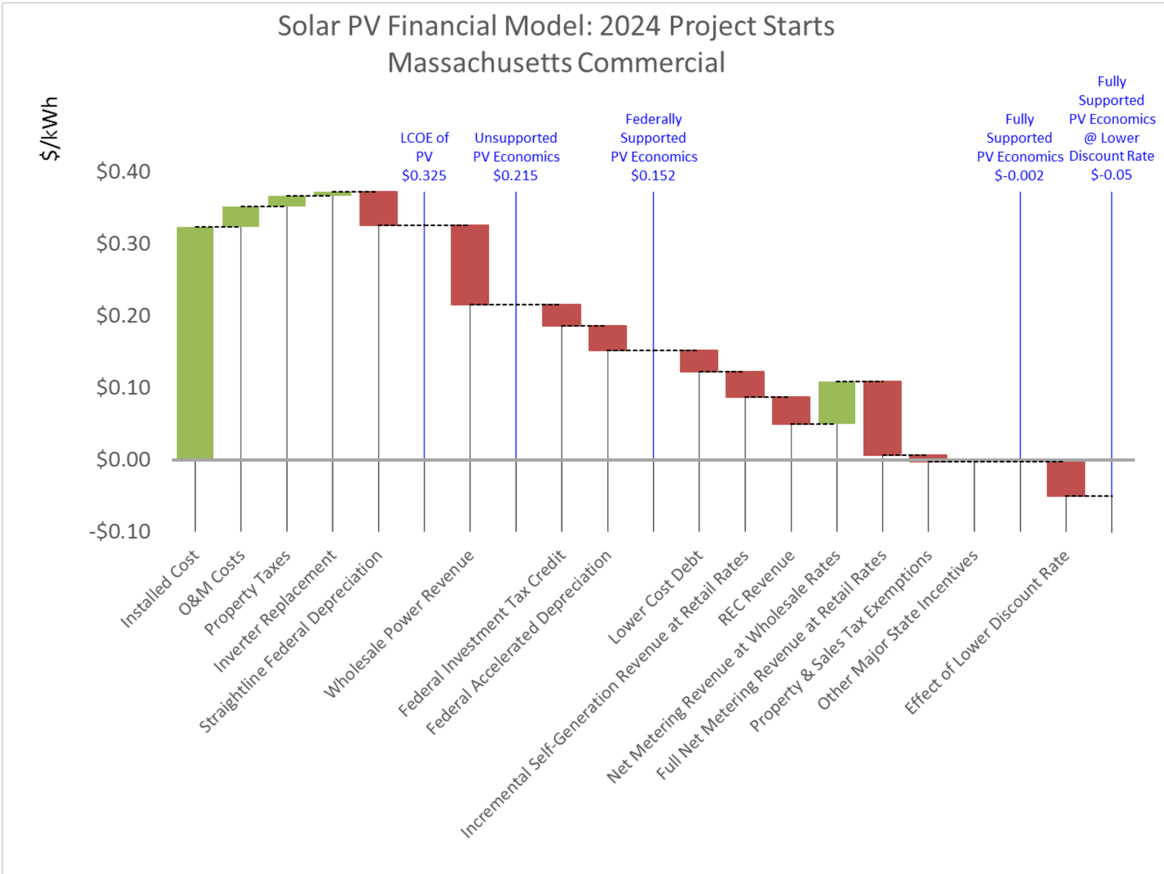


Exhibit C-9: Massachusetts Utility Scale PV Drivers, 2024 Project Starts

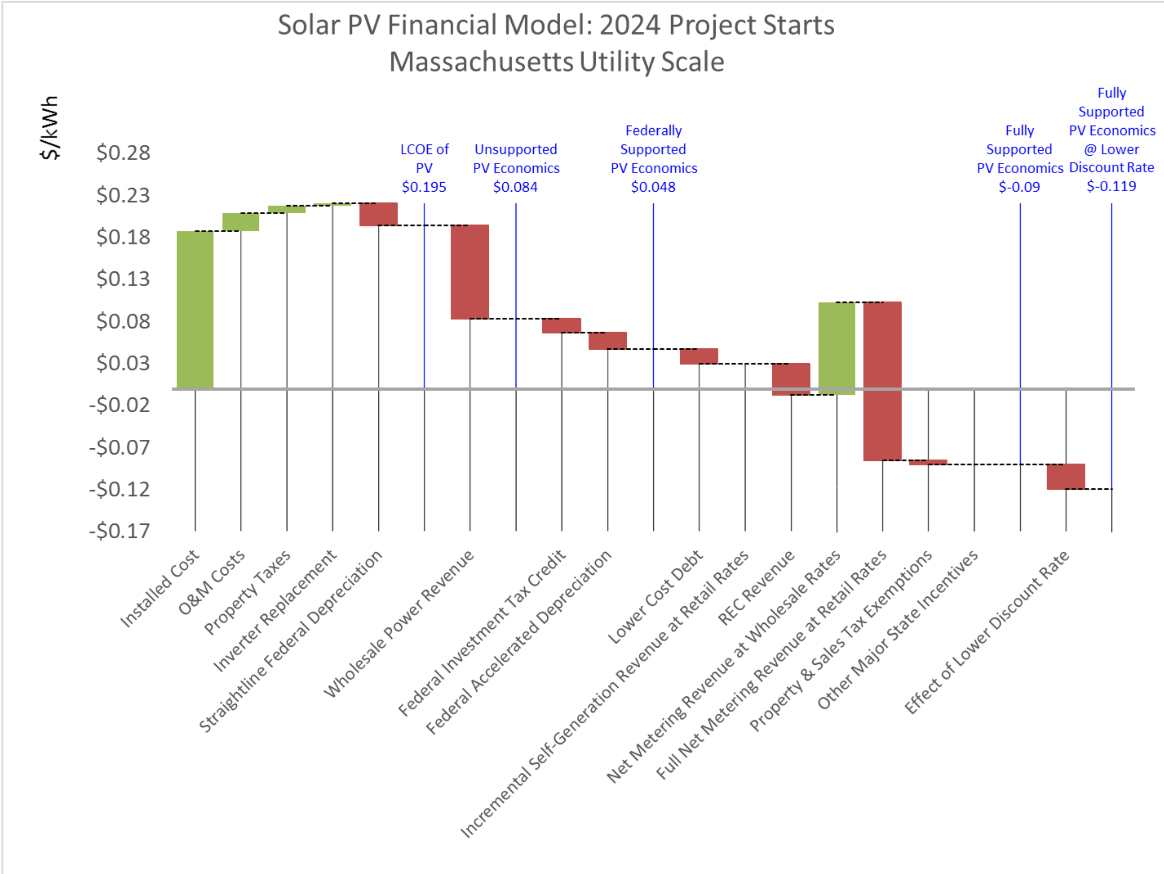


Exhibit C-10: New Hampshire Residential PV Drivers, 2024 Project Starts

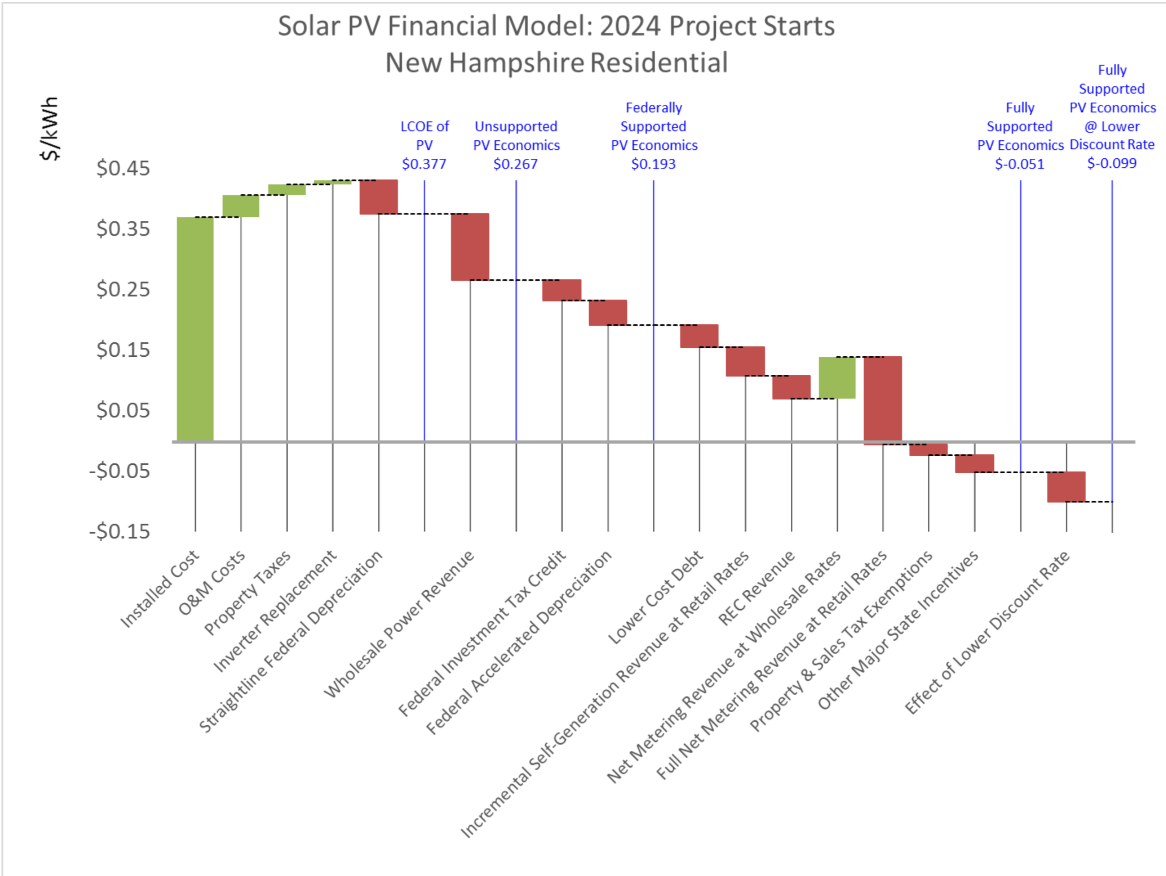


Exhibit C-11: New Hampshire Commercial PV Drivers, 2024 Project Starts

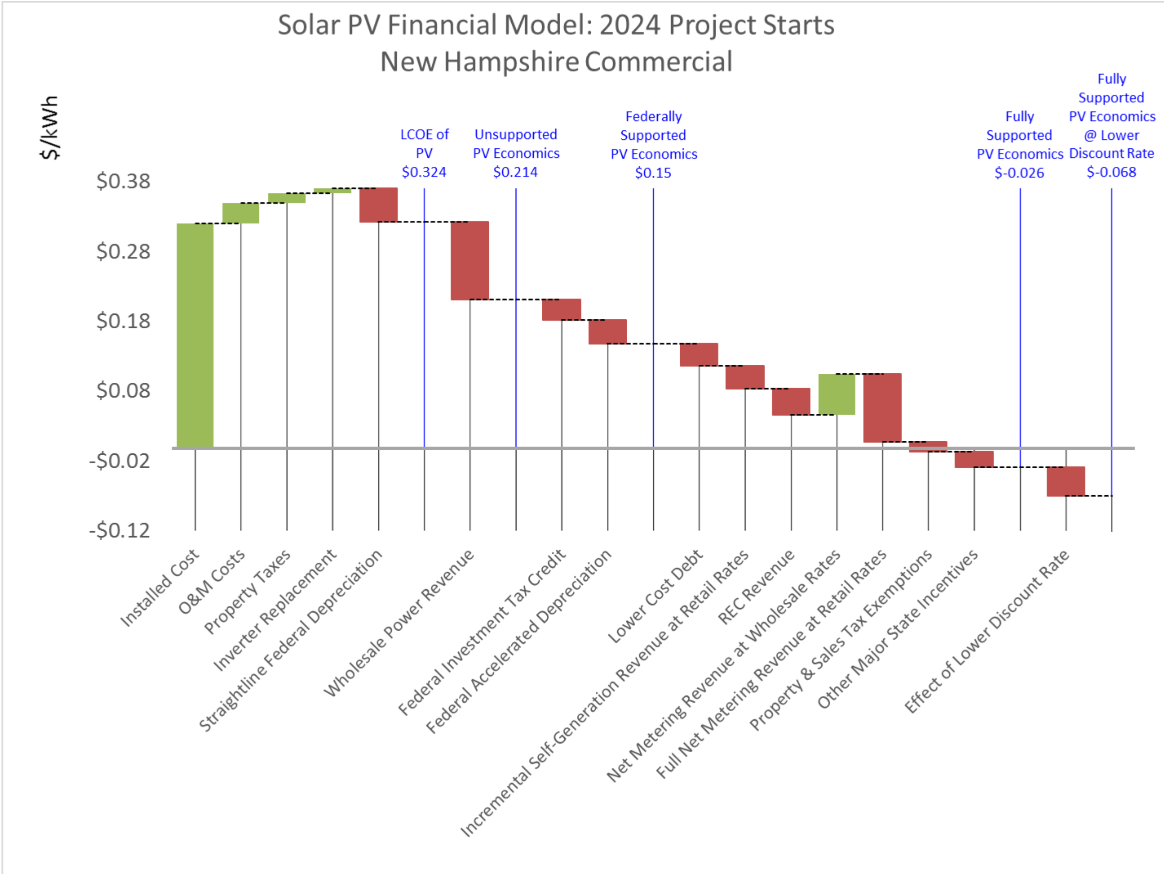


Exhibit C-12: New Hampshire Utility Scale PV Drivers, 2024 Project Starts

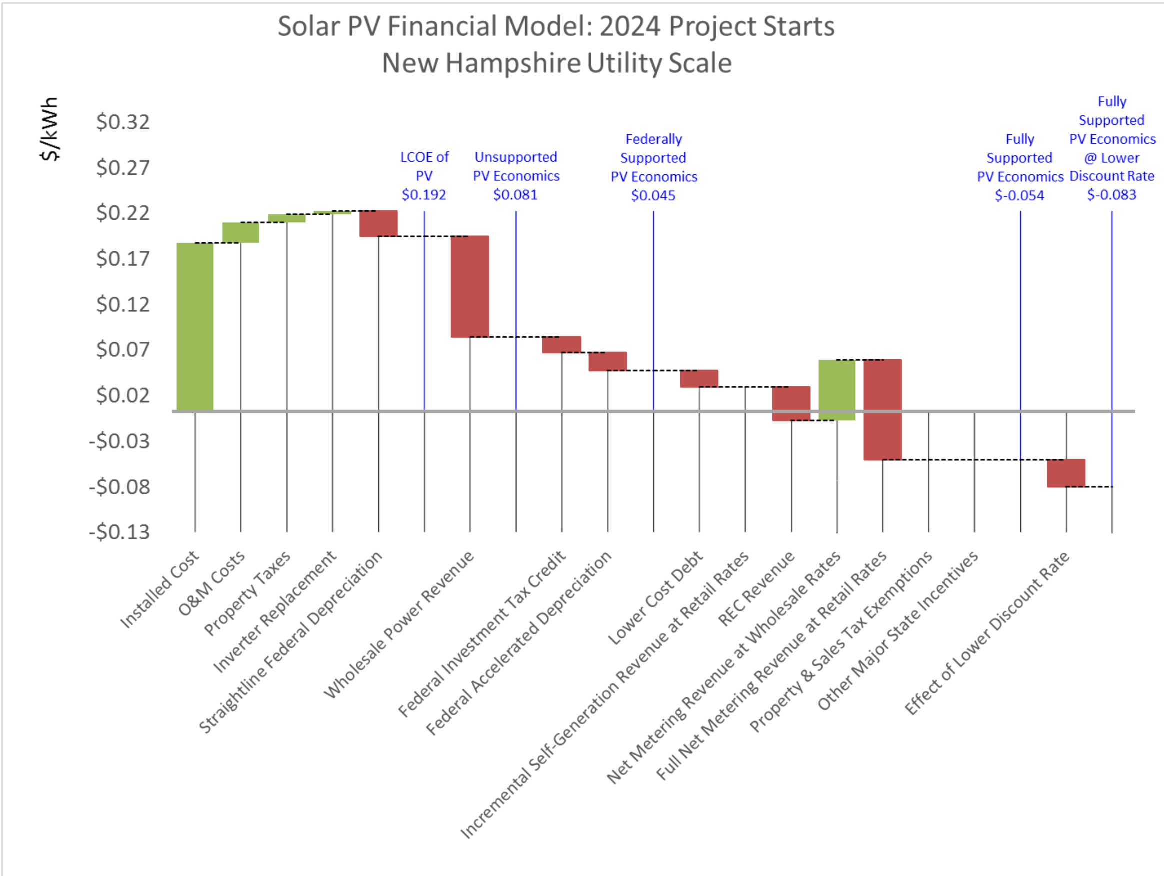


Exhibit C-13: Rhode Island Residential PV Drivers, 2024 Project Starts

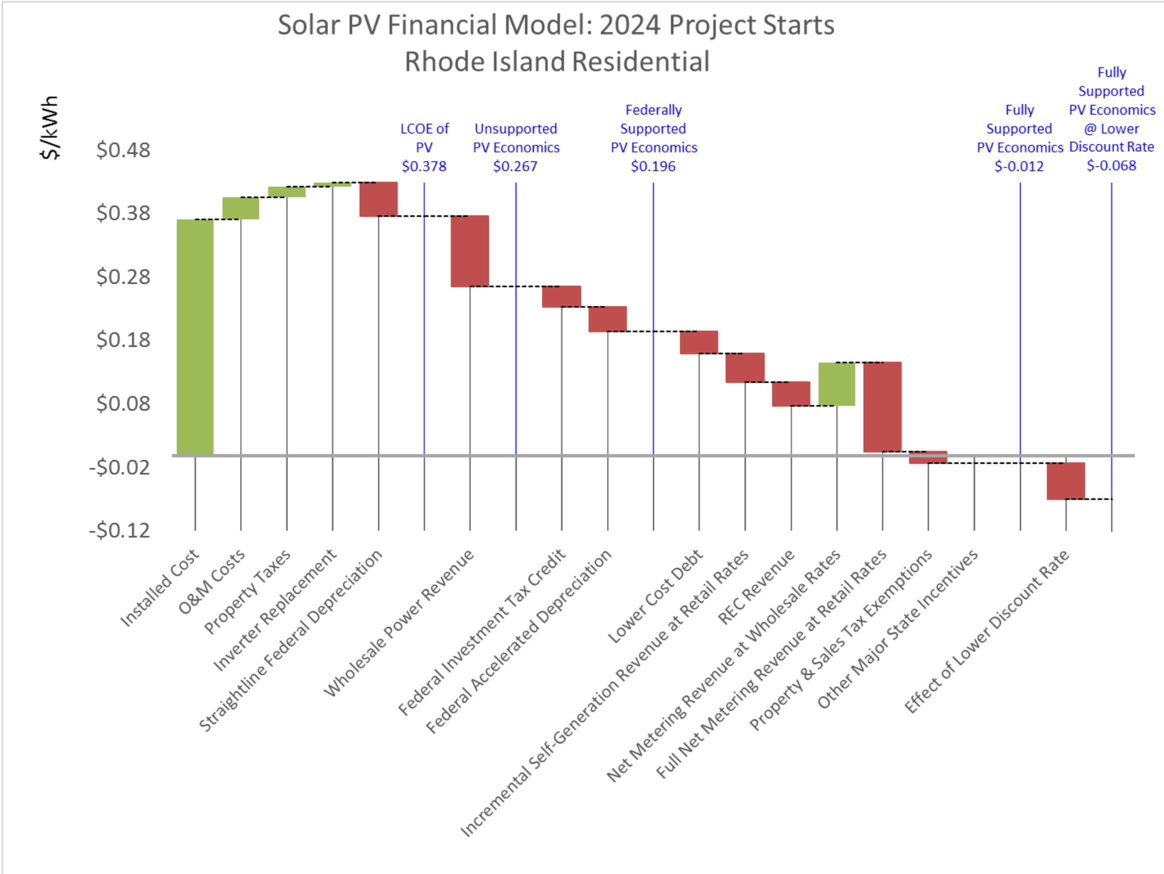


Exhibit C-14: Rhode Island Commercial PV Drivers, 2024 Project Starts

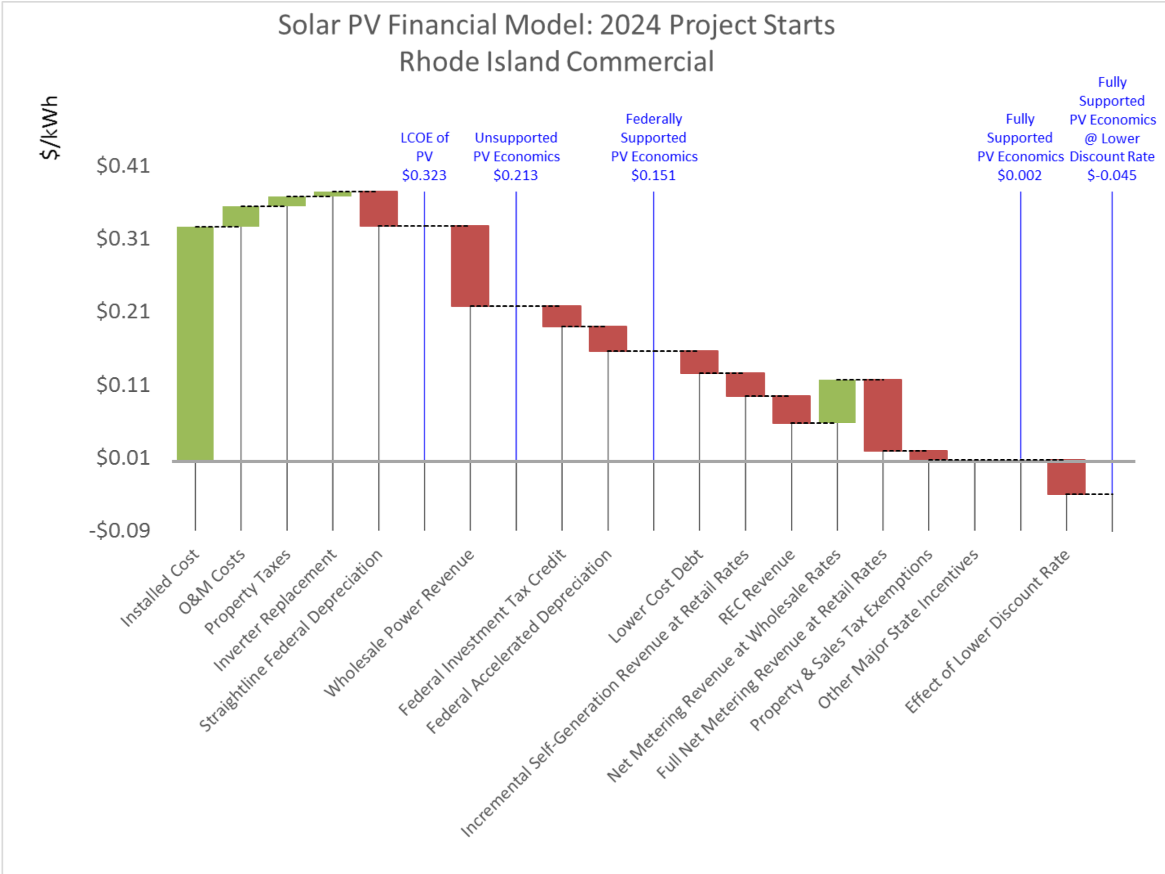


Exhibit C-15: Rhode Island Utility Scale PV Drivers, 2024 Project Starts

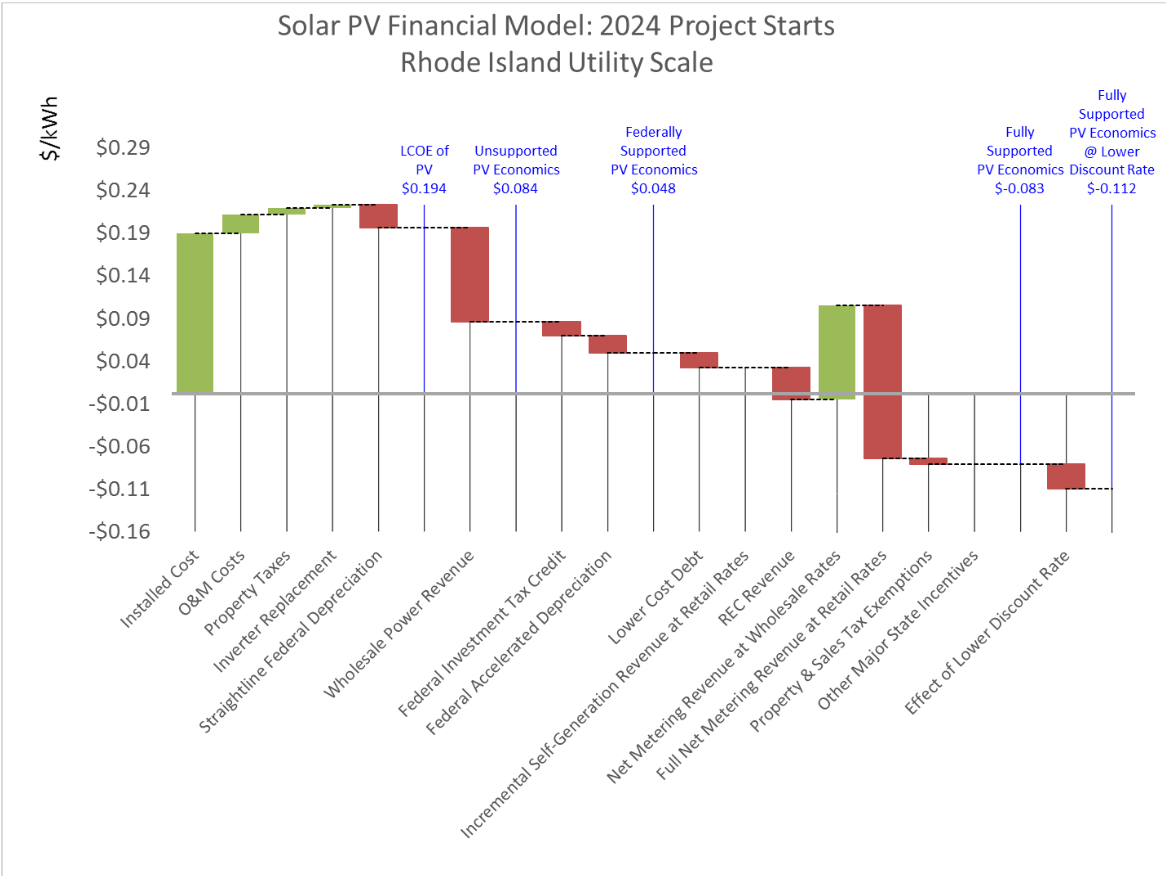


Exhibit C-16: Vermont Residential PV Drivers, 2024 Project Starts

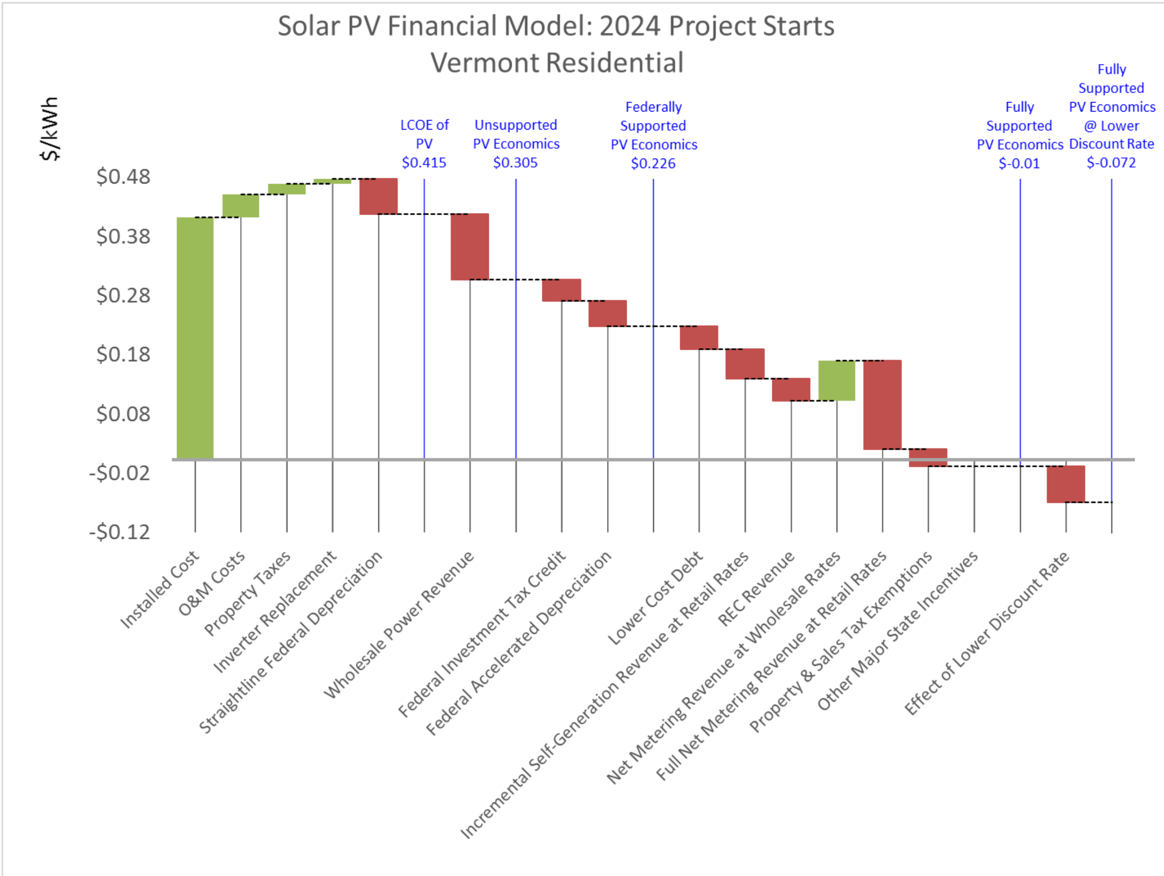


Exhibit C-17: Vermont Commercial PV Drivers, 2024 Project Starts

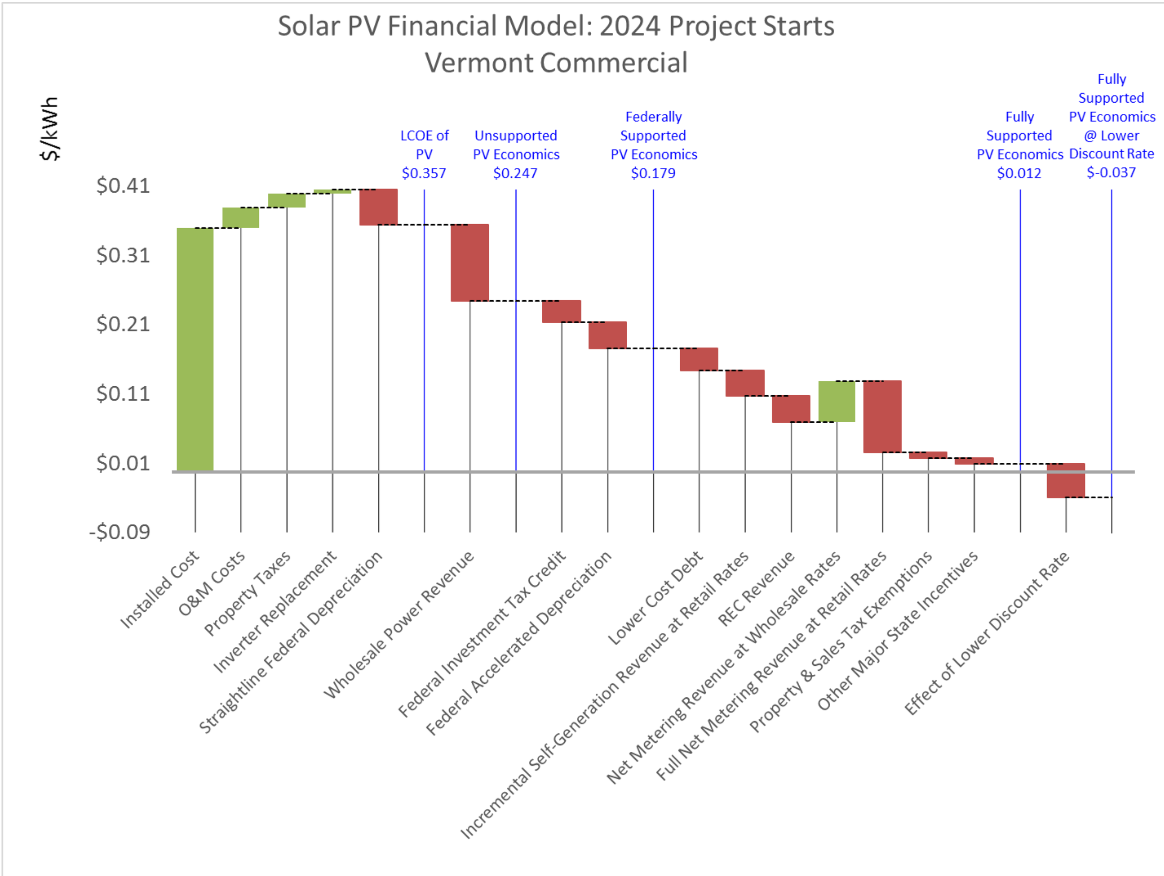
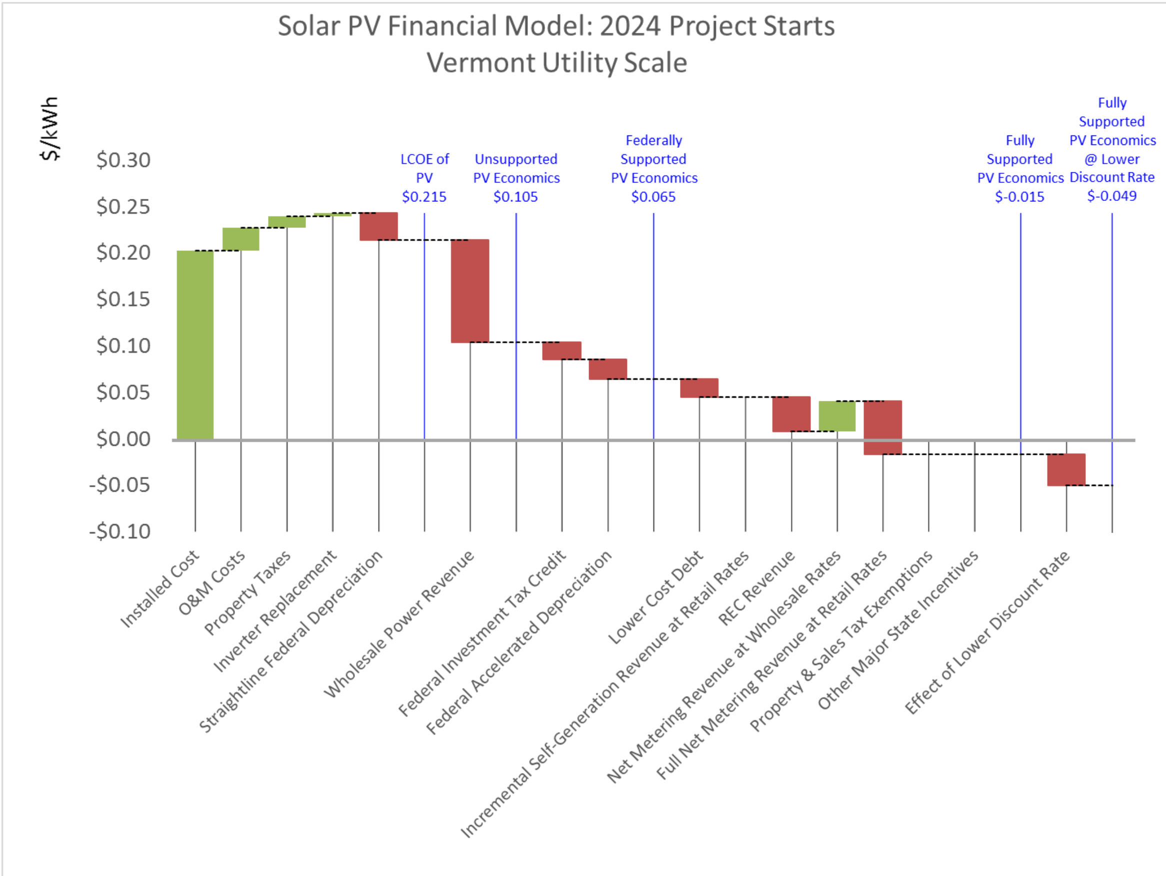


Exhibit C-18: Vermont Utility Scale PV Drivers, 2024 Project Starts



Appendix D: Alternative Scenario 1 (Selected Incentives Remain at 2015 Levels)

Exhibit D-1: Alternative Scenario 1 Outputs, 2019 Project Starts

(Data in $/kWh)

State =>	CT	CT	NH	NH	RI	RI	RI	VT	VT	VT
Customer Type =>	Residential	Commercial	Residential	Commercial	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
Installed Cost	$0.366	$0.314	$0.379	$0.329	$0.380	$0.328	$0.190	$0.417	$0.358	$0.208
O&M Costs	$0.033	$0.025	$0.035	$0.027	$0.034	$0.026	$0.021	$0.037	$0.029	$0.023
Property Taxes	$0.016	$0.014	$0.017	$0.015	$0.017	$0.014	$0.008	$0.018	$0.020	$0.013
Inverter Replacement	$0.007	$0.006	$0.007	$0.006	$0.007	$0.006	$0.004	$0.008	$0.007	$0.004
Straightline Federal Depreciation	($0.053)	($0.045)	($0.056)	($0.049)	($0.055)	($0.047)	($0.027)	($0.060)	($0.052)	($0.030)
Levelized Cost of Energy (LCOE) of PV	**$0.369**	**$0.313**	**$0.382**	**$0.328**	**$0.383**	**$0.327**	**$0.196**	**$0.421**	**$0.362**	**$0.217**
Wholesale Power Revenue	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)
Unsupported PV Economics	**$0.279**	**$0.223**	**$0.292**	**$0.238**	**$0.293**	**$0.237**	**$0.106**	**$0.331**	**$0.272**	**$0.128**
Federal Investment Tax Credit	($0.032)	($0.028)	($0.034)	($0.030)	($0.033)	($0.029)	($0.017)	($0.037)	($0.032)	($0.018)
Federal Accelerated Depreciation	($0.038)	($0.033)	($0.041)	($0.036)	($0.040)	($0.034)	($0.020)	($0.044)	($0.038)	($0.022)
Federally Supported PV Economics	**$0.208**	**$0.163**	**$0.217**	**$0.173**	**$0.220**	**$0.174**	**$0.069**	**$0.250**	**$0.203**	**$0.087**
Lower Cost Debt	($0.034)	($0.029)	($0.037)	($0.032)	($0.035)	($0.031)	($0.018)	($0.039)	($0.034)	($0.019)
Incremental Self-Generation Revenue at Retail Rates	($0.055)	($0.040)	($0.046)	($0.034)	($0.074)	($0.051)	$0.000	$0.000	$0.000	$0.000
REC Revenue	($0.075)	($0.075)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)
Net Metering Revenue at Wholesale Rates	$0.055	$0.048	$0.055	$0.048	$0.056	$0.049	$0.090	$0.090	$0.090	$0.090
Full Net Metering Revenue at Retail Rates	($0.141)	($0.094)	($0.130)	($0.088)	($0.176)	($0.109)	($0.128)	($0.220)	($0.198)	($0.124)
Property & Sales Tax Exemptions	($0.026)	($0.023)	($0.017)	($0.015)	($0.018)	($0.013)	($0.008)	($0.029)	($0.009)	$0.000
Other Major State Incentives	$0.000	$0.000	($0.063)	($0.047)	$0.000	$0.000	$0.000	$0.000	($0.008)	$0.000
Fully Supported PV Economics	**($0.069)**	**($0.051)**	**($0.065)**	**($0.037)**	**($0.071)**	**($0.024)**	**($0.038)**	**$0.007**	**$0.001**	**($0.010)**
Effect of Lower Discount Rate	($0.053)	($0.044)	($0.038)	($0.034)	($0.049)	($0.044)	($0.029)	($0.061)	($0.047)	($0.026)
Fully Supported PV Economics @ Lower Discount Rate	**($0.122)**	**($0.094)**	**($0.102)**	**($0.071)**	**($0.120)**	**($0.068)**	**($0.067)**	**($0.054)**	**($0.046)**	**($0.036)**

Note: Outputs above are only displayed where they are different than the baseline outputs in Section 4.

Exhibit D-2: Alternative Scenario 1 Outputs, 2024 Project Starts

(Data in $/kWh)

State =>	NH	NH
Customer Type =>	Residential	Commercial
Installed Cost	$0.372	$0.323
O&M Costs	$0.036	$0.029
Property Taxes	$0.017	$0.015
Inverter Replacement	$0.007	$0.006
Straightline Federal Depreciation	($0.055)	($0.048)
Levelized Cost of Energy (LCOE) of PV	**$0.377**	**$0.324**
Wholesale Power Revenue	($0.110)	($0.110)
Unsupported PV Economics	**$0.267**	**$0.214**
Federal Investment Tax Credit	($0.034)	($0.029)
Federal Accelerated Depreciation	($0.040)	($0.035)
Federally Supported PV Economics	**$0.193**	**$0.150**
Lower Cost Debt	($0.036)	($0.031)
Incremental Self-Generation Revenue at Retail Rates	($0.048)	($0.033)
REC Revenue	($0.037)	($0.037)
Net Metering Revenue at Wholesale Rates	$0.068	$0.059
Full Net Metering Revenue at Retail Rates	($0.145)	($0.098)
Property & Sales Tax Exemptions	($0.017)	($0.015)
Other Major State Incentives	($0.060)	($0.045)
Fully Supported PV Economics	**($0.082)**	**($0.049)**
Effect of Lower Discount Rate	($0.038)	($0.034)
Fully Supported PV Economics @ Lower Discount Rate	**($0.120)**	**($0.083)**

Note: Outputs above are only displayed where they are different than the baseline outputs in Section 4.

Appendix E: Alternative Scenario 2 (Selected Incentives are Unavailable)

Exhibit E-1: Alternative Scenario 2 Outputs, 2019 Project Starts

(Data in $/kWh)

State =>	CT	CT	NH	NH	RI	RI	RI	VT	VT	VT
Customer Type =>	Residential	Commercial	Residential	Commercial	Residential	Commercial	Utility Scale	Residential	Commercial	Utility Scale
Installed Cost	$0.366	$0.314	$0.379	$0.329	$0.380	$0.328	$0.190	$0.417	$0.358	$0.208
O&M Costs	$0.033	$0.025	$0.035	$0.027	$0.034	$0.026	$0.021	$0.037	$0.029	$0.023
Property Taxes	$0.016	$0.014	$0.017	$0.015	$0.017	$0.014	$0.008	$0.018	$0.020	$0.013
Inverter Replacement	$0.007	$0.006	$0.007	$0.006	$0.007	$0.006	$0.004	$0.008	$0.007	$0.004
Straightline Federal Depreciation	($0.053)	($0.045)	($0.056)	($0.049)	($0.055)	($0.047)	($0.027)	($0.060)	($0.052)	($0.030)
Levelized Cost of Energy (LCOE) of PV	**$0.369**	**$0.313**	**$0.382**	**$0.328**	**$0.383**	**$0.327**	**$0.196**	**$0.421**	**$0.362**	**$0.217**
Wholesale Power Revenue	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)	($0.090)
Unsupported PV Economics	**$0.279**	**$0.223**	**$0.292**	**$0.238**	**$0.293**	**$0.237**	**$0.106**	**$0.331**	**$0.272**	**$0.128**
Federal Investment Tax Credit	($0.032)	($0.028)	($0.034)	($0.030)	($0.033)	($0.029)	($0.017)	($0.037)	($0.032)	($0.018)
Federal Accelerated Depreciation	($0.038)	($0.033)	($0.041)	($0.036)	($0.040)	($0.034)	($0.020)	($0.044)	($0.038)	($0.022)
Federally Supported PV Economics	**$0.208**	**$0.163**	**$0.217**	**$0.173**	**$0.220**	**$0.174**	**$0.069**	**$0.250**	**$0.203**	**$0.087**
Lower Cost Debt	($0.034)	($0.029)	($0.037)	($0.032)	($0.035)	($0.031)	($0.018)	($0.039)	($0.034)	($0.019)
Incremental Self-Generation Revenue at Retail Rates	($0.055)	($0.040)	($0.046)	($0.034)	($0.044)	($0.038)	$0.000	$0.000	$0.000	$0.000
REC Revenue	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)	($0.044)
Net Metering Revenue at Wholesale Rates	$0.055	$0.048	$0.055	$0.048	$0.056	$0.049	$0.090	$0.090	$0.090	$0.027
Full Net Metering Revenue at Retail Rates	($0.141)	($0.094)	($0.130)	($0.088)	($0.127)	($0.094)	($0.174)	($0.217)	($0.183)	($0.055)
Property & Sales Tax Exemptions	($0.026)	($0.023)	($0.017)	($0.015)	($0.018)	($0.013)	($0.008)	($0.029)	($0.009)	$0.000
Other Major State Incentives	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	($0.008)	$0.000
Fully Supported PV Economics	**($0.037)**	**($0.019)**	**($0.002)**	**$0.009**	**$0.008**	**$0.003**	**($0.083)**	**$0.010**	**$0.015**	**($0.004)**
Effect of Lower Discount Rate	($0.056)	($0.047)	($0.058)	($0.049)	($0.057)	($0.048)	($0.030)	($0.062)	($0.050)	($0.034)
Fully Supported PV Economics @ Lower Discount Rate	**($0.093)**	**($0.066)**	**($0.060)**	**($0.040)**	**($0.049)**	**($0.045)**	**($0.113)**	**($0.052)**	**($0.035)**	**($0.038)**

Note: Outputs above are only displayed where they are different than the baseline outputs in Section 4.

Exhibit E-2: Alternative Scenario 2 Outputs, 2024 Project Starts

(Data in $/kWh)

State =>	NH	NH
Customer Type =>	Residential	Commercial
Installed Cost	$0.372	$0.323
O&M Costs	$0.036	$0.029
Property Taxes	$0.017	$0.015
Inverter Replacement	$0.007	$0.006
Straightline Federal Depreciation	($0.055)	($0.048)
Levelized Cost of Energy (LCOE) of PV	**$0.377**	**$0.324**
Wholesale Power Revenue	($0.110)	($0.110)
Unsupported PV Economics	**$0.267**	**$0.214**
Federal Investment Tax Credit	($0.034)	($0.029)
Federal Accelerated Depreciation	($0.040)	($0.035)
Federally Supported PV Economics	**$0.193**	**$0.150**
Lower Cost Debt	($0.036)	($0.031)
Incremental Self-Generation Revenue at Retail Rates	($0.048)	($0.033)
REC Revenue	($0.037)	($0.037)
Net Metering Revenue at Wholesale Rates	$0.068	$0.059
Full Net Metering Revenue at Retail Rates	($0.145)	($0.098)
Property & Sales Tax Exemptions	($0.017)	($0.015)
Other Major State Incentives	$0.000	$0.000
Fully Supported PV Economics	**($0.022)**	**($0.005)**
Effect of Lower Discount Rate	($0.057)	($0.048)
Fully Supported PV Economics @ Lower Discount Rate	**($0.079)**	**($0.053)**

Note: Outputs above are only displayed where they are different than the baseline outputs in Section 4.

Appendix F: PV Installed Cost Projections & PV Equipment Trade Tariff Effects

There is a relative scarcity of publicly-available, recent, long-range forecasts of U.S. PV installed costs conducted by government agencies or other entities outside of industry. However, the Energy Information Administration of the U.S. Department of Energy (DOE) publishes an *Annual Energy Outlook (AEO)* with annual PV cost projections to 2040.

In real dollars, the *AEO* 2014 reference case[102] contains a forecasted average cost reduction of 1.37% per kW of installed capacity annually. Cumulatively, that translates into a 30% real cost reduction between 2014 and 2040. The *AEO* forecast shows PV costs declining at higher rates during the 2015-2017 period (over 4% per year) than during subsequent periods.

Black & Veatch, for the National Renewable Energy Laboratory (NREL), published a study two years ago that forecasted installed system costs for a range of generation technologies, including several types of PV.[103] That study shows residential, commercial, and utility scale (1 MW fixed-tilt) system costs declining in total by 29%, 28%, and 19%, respectively, between 2015 and 2040 in real dollars. Those decline rates are similar to the *AEO* projections.

DOE's *SunShot Vision Study* contains a more aggressive scenario, with PV installed costs reaching $\$1.50/\text{watt}_{DC}$, $\$1.25/\text{watt}_{DC}$, and $\$1.00/\text{watt}_{DC}$ by 2020, respectively for residential, commercial, and utility scale systems.[104] Though PV prices have declined substantially since the *SunShot Vision Study* was published, they must continue to decline rapidly if they are to reach the SunShot 2020 projections/goals.[105]

While trade tariffs imposed on certain PV products (cells and panels) produced by Chinese and Taiwanese firms[106] can be expected to affect U.S. installed PV costs somewhat, the effect is mitigated by two factors. First, there are PV manufacturers from outside of China and Taiwan, including in the U.S., that can provide PV equipment without being subject to tariffs. Second, PV panels[107] (also called modules) comprise a minority of PV installed costs. Even if the tariffs raised average panel prices in the U.S. by 25% (roughly half of the combined anti-dumping and anti-subsidy tariff imposed on certain Chinese and Taiwanese firms), that would only translate into a roughly 5% to 10% increase in total PV system costs.

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[102] See http://www.eia.gov/forecasts/aeo/.

[103] Black & Veatch for NREL, *Cost Report: Cost and Performance Data for Power Generation Technologies*, http://bv.com/docs/reports-studies/nrel-cost-report.pdf.

[104] See http://energy.gov/eere/sunshot/sunshot-vision-study.

[105] In this recent report, PV installed costs in the U.S. for residential systems in a subset of state markets in the first half of 2014 had a median value of $\$4.50/\text{watt}_{DC}$. For commercial systems from 10-100 kW in capacity, median costs were $\$3.97/\text{watt}_{DC}$, and they were $\$3.52/\text{watt}_{DC}$ for commercial systems with capacities over 100 kW. See U.S. Department of Energy (with National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory), *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition*, September 22, 2014, http://www.nrel.gov/docs/fy14osti/62558.pdf.

[106] There are two types of tariffs that can be applied, anti-dumping and anti-subsidy (countervailing duty). See http://www.pv-magazine.com/news/details/beitrag/solar-trade-war--us-imposes-preliminary-anti-dumping-tariffs-of-26-165-on-solar-pv-from-china--taiwan_100015851/#axzz3JlKHjsOu.

[107] Solar cells are combined into panels, so this discussion emphasizes the cost effects of panels, which are the component purchased by PV project developers.

Appendix G: Overview of PV Financial Products

Exhibit G-1: PV Financial Products Mapped to Several Types of PV Hosts and Investors

PV Host or Investor Type	Physical Description of Project	Transaction Description	Example Providers	Notes on Financing Involved
Homeowner	2 to 10 kW projects typically on the roof of a home and feeding power directly to the host.	Homeowner enters into a turnkey, long-term power purchase (PPA) or lease agreement with the system owner. The owner/developer will typically aggregate many projects into a portfolio and, then, sell the bundled projects into a finance facility (i.e., investment pool) that includes debt, strategic equity investors, and tax equity investors.	SolarCity Vivint SunRun SunPower	Projects are frequently third party financed through lease or PPA. However, outright system purchases by homeowners (with or without loans) are still common, but high PV first costs, as well as project ownership and REC complexity, dissuade many homeowners from purchasing systems. Property Assessed Clean Energy (PACE) programs allow homeowners to indirectly benefit from low-cost local government financing for PV systems.
Commercial and Industrial Business or Non-Profit or Government Agency	10 to 2,000 kW projects typically on the roof or property owned by host and feeding power directly to the host.	Customer (i.e., host) enters into an agreement to purchase power from the system owner/operator over a long term (15 to 25 years). Or, if the host has tax liability and desire to manage project, it can be self-financed.	SunPower SunEdison NRG Astrum	Projects are frequently third party financed through leases or PPAs, though self-ownership occurs regularly. Non-profits and government agencies must use third-party private ownership structures if they wish to benefit from PV tax incentives.
Community Solar **(shared net metering by multiple legal entities)**	Often 250kW+ projects.	Project developers work with subscribers located within the service territory of the utility where the project is located. These subscribers (individuals, businesses, non-profits, or government agencies) enter into agreements to purchase blocks of energy generated by the system.	SunShare Sol Partners Clean Energy Collective	Community solar projects are typically financed similarly to single-buyer PV projects of the same size.
Independent Power Producer	2,000 to 30,000+ kW projects located adjacent to transmission or distribution lines and feeding energy directly into the grid.	Project developer enters into a long-term purchase agreement with the utility (~20 years) that often includes the bundled sale of both the power and environmental attributes (i.e., RECs) generated by the system.	Recurrent NRG SunEdison	Projects are typically third-party financed through a power purchase agreement (PPA).
Fixed Income Financing (e.g., "YieldCos")	Aggregations of projects.	This financing mechanism is utilized to sell groups of smaller operating projects to investors that value long-term stable cash flows. The sale of the projects is typically to entities such as pension funds, YieldCos, and other fixed income structures.	SunEdison SunPower SolarCity Vivint	The fixed income facility will buyout the equity and debt of the project and looks for moderate returns on the purchase of the project.