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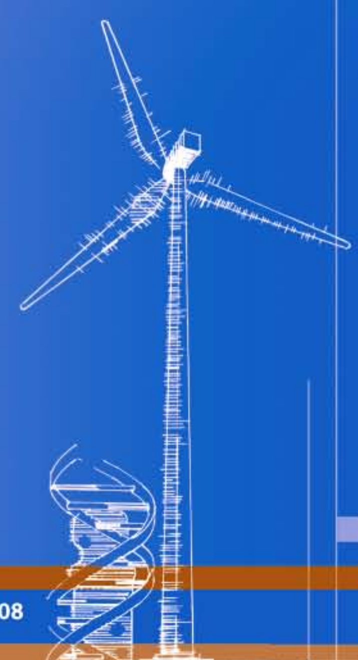
The Solar Deployment System (SolarDS) Model: Documentation and Sample Results

Paul Denholm, Easan Drury, and Robert Margolis

Technical Report
NREL/TP-6A2-45832
September 2009



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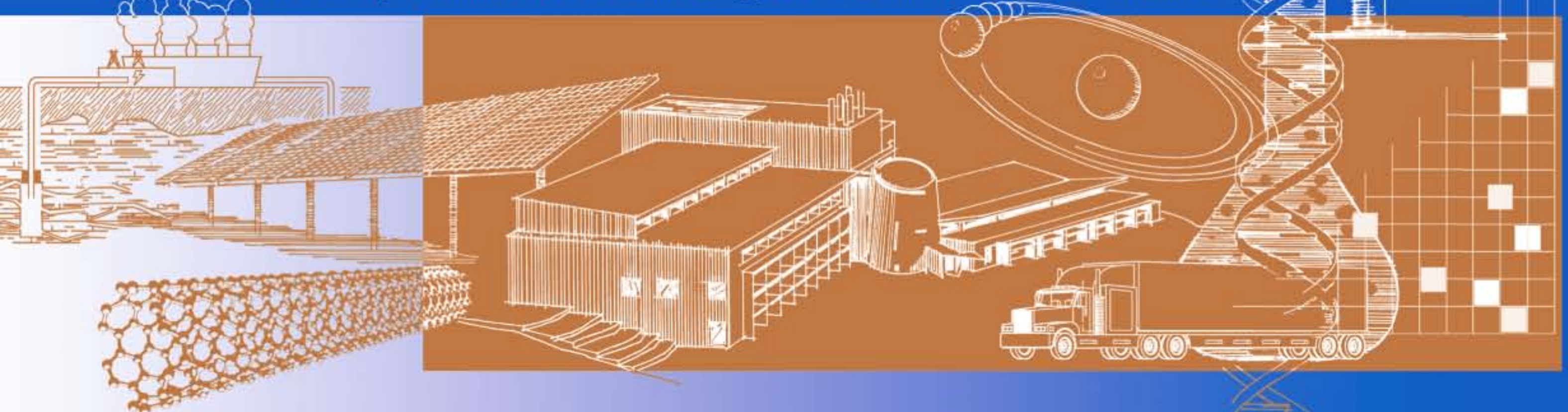

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Executive Summary

The Solar Deployment System (SolarDS) model is a geospatially rich, bottom-up, market-penetration model that simulates the potential adoption of photovoltaics (PV) on residential and commercial rooftops in the continental United States through 2030. SolarDS was developed by the National Renewable Energy Laboratory (NREL) to examine the market competitiveness of PV based on regional solar resources, capital costs, electricity prices, utility rate structures, and federal and local incentives. SolarDS calculations are run at a high level of disaggregation by calculating PV generation in 216 solar resource regions, shown in Figure ES-1, and combining PV output with state-based electricity rate distributions from 3000 utilities. Regional PV financial performance is used to simulate PV adoption rates for each customer type and building type. SolarDS then aggregates regional PV adoption to the state and national level. This document introduces the SolarDS model, describes how it works, and shows model results for a series of PV penetration scenarios.

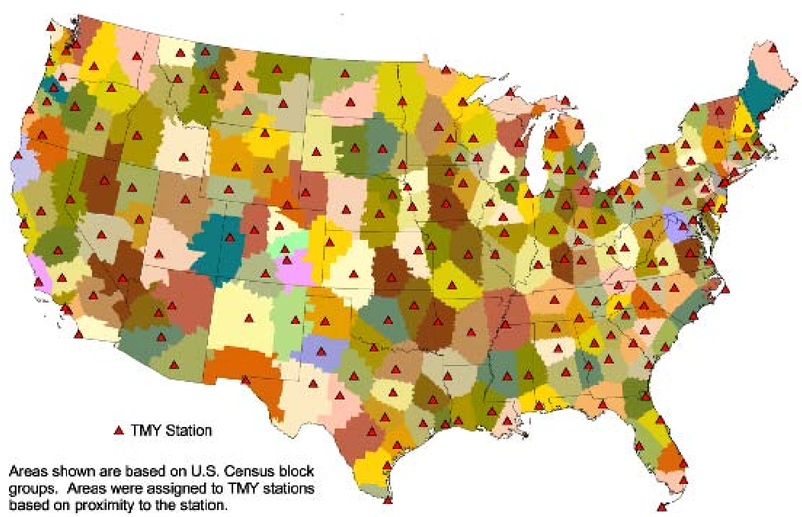

Figure ES-1. The 216 solar resource regions used in SolarDS with observation stations shown as red triangles.

SolarDS Components

Figure ES-2 shows the main components of the SolarDS model, which are described in detail below.

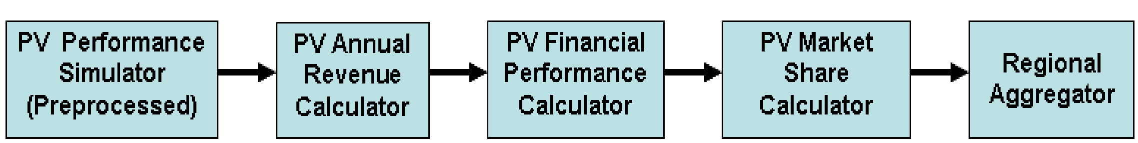

Figure ES-2. SolarDS model structure

1. **PV Performance Simulator.** The PV performance simulator estimates the amount of electricity that a PV module of a given size will generate each hour, for hundreds of locations in the continental United States and for a variety of module orientations. Hourly PV performance is simulated at 216 locations in the using solar insolation and weather data from Typical Meteorological Year (TMY) stations. PV output is calculated for multiple module orientations to characterize a range of roof types and orientations.
2. **PV Annual Revenue Calculator**. The annual revenue calculator combines the PV technical performance simulations with electricity rates, electricity rate structures, and building load simulations to calculate the expected annual savings for a multiple PV systems in each location. PV revenue is defined as the avoided cost of electricity and is calculated from the combination of hourly PV output and regional electricity rates. For residential buildings, annual PV revenues are calculated for both standard flat rates and time-of-use rates. For commercial buildings, annual revenues are calculated for standard flat rates, time-of-use rates, and demand-based rates.
3. **PV Financial Performance Calculator.** The financial performance calculator combines the annual revenue generated by a PV system with PV costs and financing assumptions to generate financial performance metrics for individual PV systems. PV costs are based on current price data and price projections from the Energy Information Agency (EIA) or the U.S. Department of Energy (DOE) Solar Energy Technologies Program (SETP) targets. Users can also specify their own PV cost projections or set PV learning rates (which characterize the decrease in cost with each doubling of cumulative installed capacity). Federal and state incentives are applied, reducing the up-front cost of PV systems. A distribution of financing parameters is used including cash payments, home-equity type loans, and conventional loans. For residential PV systems, the financial performance module calculates a “time-to-net-positive” cash flow as the base financial metric. For commercial systems, the internal rate of return (IRR) is calculated as the base financial metric.
4. **PV Market Share Calculator.** The PV market share calculator uses financial performance metrics (generated in the financial performance calculator) to simulate PV purchasing probabilities that are unique to each solar resource region, local utility electricity rate and rate structure, customer type, customer financing, panel orientations, building size, and building age. Financial performance metrics are used to calculate both the total potential PV market share (using market-penetration curves) and the adoption rate (using Bass diffusion). Different PV market-penetration curves are used to characterize residential and commercial customers in new and retrofit markets.
5. **Regional Aggregator.** The regional aggregator module combines the hundreds of thousands of PV adoption probabilities with the number of buildings associated with each unique system type, and aggregates PV adoption statistics to the state and national level. The number of residential and commercial buildings suitable for PV is generated using census data and projected into the future using population growth estimates. The total number of buildings that adopt PV is

calculated by combining PV purchasing probabilities with the total number of buildings suitable for PV and then aggregates over each system type and region to generate state and national PV adoption statistics. The model outputs the cumulative and annual installed PV capacity, the number of buildings with PV, fractional PV market share, and PV payback times at the state and national levels for each time period.

SolarDS Results

SolarDS simulates a wide range of installed PV capacity for a wide range of user-specified input parameters. In preliminary model runs, we have simulated PV market-penetration levels from 15 to 193 GW by 2030, as shown in Figure ES-3. SolarDS results are primarily driven by three model assumptions: (1) future PV cost reductions, (2) the maximum PV market share assumed for systems with a given financial performance, and (3) PV financing parameters and policy-driven assumptions, such as the possible future cost of carbon emissions.

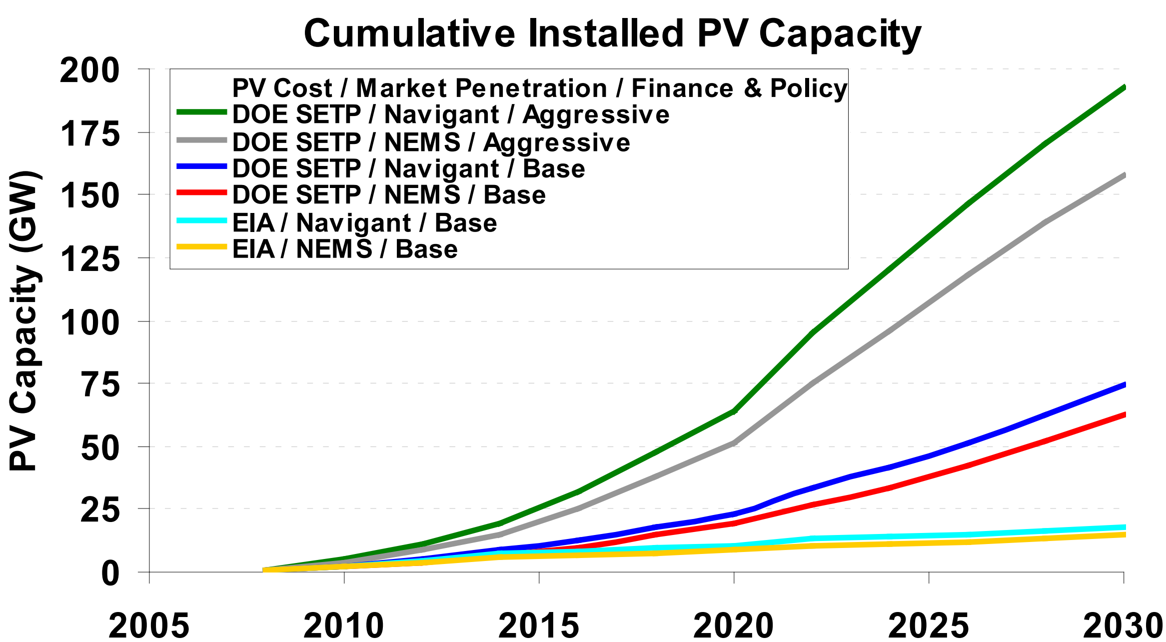

Figure ES-3. Cumulative installed PV capacity through 2030 for a range of model input parameters, including PV costs (EIA and DOE SETP), PV market adoption rates (NEMS and Navigant), and PV financing and policy assumptions (base case and aggressive case)

The lower range of PV penetration represents higher PV costs, based on EIA cost projections, where PV reaches $4.23/W for residential systems and $2.85/W for commercial systems by 2030.[1] The higher range of PV penetration represents lower PV costs, based on cost projections from the SETP targets, where residential and commercial PV reaches $2.10/W and $1.66/W, respectively, by 2030. The highest PV penetration scenarios include attractive PV financing parameters (e.g. attractive loan rates, increased

[1] Here and elsewhere, PV costs and revenues are given in nominal $2008 U.S. dollars. All model interest and escalation rates are real, not nominal.

loan terms, lower down payment fractions), an annual increase in electricity rates of 1%, and the value added for avoided carbon emissions. The large range in SolarDS results illustrates the model's sensitivity to key parameters, where simulated PV adoption is primarily driven by PV costs, financing parameters and the assumption relating PV financial performance to PV market share. Results are discussed in detail in section 4.

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1 Background and Introduction

1.1 Existing DOE PV Market-Penetration Models

The primary market-penetration model used by the Energy Information Administration (EIA) is the National Energy Modeling System (NEMS). NEMS is a very large model that covers all sectors of the U.S. energy economy with sufficient detail to analyze many energy issues (LaCommare et al. 2003, EIA 2008a, 2008b, 2008c). NEMS models the market penetration of rooftop solar PV within two building modules: the Residential Sector Demand Module (EIA 2008b) and the Commercial Sector Demand Module (EIA 2008a). NEMS is a complex model designed to evaluate the entire U.S. energy system–not individual technologies–in detail. As a result, it is difficult to simulate the complexity of the distributed PV market using NEMS (Margolis and Wood 2004). Other U.S. PV market-penetration models include a spreadsheet model developed by Navigant Consulting, Inc. (NCI) for the DOE's Renewable System Interconnection study in 2007 (Paidipati et al. 2008).

Because NEMS and other models do not consider either the large range of building and customer types or the geographical variation in PV performance and electricity rates, the Solar Deployment System (SolarDS) model was developed as a stand-alone tool to evaluate the potential market penetration of residential and commercial PV.

1.2 SolarDS Design Goals

SolarDS was developed as an easy-to-use alternative to the NEMS model that can provide a more detailed simulation of market-penetration dynamics for distributed PV technologies under a range of assumptions. Other design goals included short model run times (less than one hour) and reasonably transparent model assumptions and formulation.

SolarDS uses many of the same input parameters as NEMS and employs a method for calculating PV market penetration that is similar to the method used by NEMS. Inputs to SolarDS include regional solar insolation data, which are combined with a distribution of current electricity rates and rate structures, to calculate the value of PV in multiple regions.

1.3 SolarDS Model Formulation

SolarDS was written as a collection of Visual Basic for Applications (VBA) modules with a Microsoft Excel interface. The front end was designed to allow users to easily modify key input parameters, and thus simulate PV market penetration under a variety of assumptions.

Figure 1 illustrates the basic structure of the SolarDS model, which consists of an input database, a PV Annual Value Preprocessor, and the main SolarDS module. The PV Annual Value Preprocessor simulates the annual revenue generated by a PV system in each geographical location. The preprocessor also simulates module orientation, electricity price region, and utility rate structure. The main SolarDS module combines the annual revenue and the cost of the PV system (including various incentives and financing scenarios) to produce a financial performance metric. This performance metric is then used to calculate a market share, which is aggregated over all regions to estimate state and national PV market share. SolarDS forecasts PV market share in two-year increments from 2008 to 2030.[2]

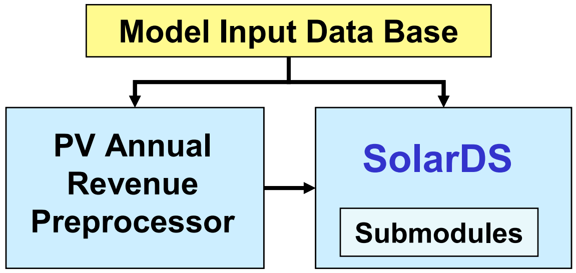

Figure 1. SolarDS components

Section 2 describes the PV annual value module in more detail, and section 3 describes the financial performance calculations used to determine PV market share.

2 PV Annual Value Preprocessor

The Annual Value Preprocessor calculates the annual revenue generated by residential and commercial PV systems with a variety of system orientations, electricity rates, and utility rate structures. Figure 2 shows an overview of the major components of SolarDS, including the PV Annual Value Preprocessor, which calculates the revenue generated by PV systems for thousands of combinations of input parameters including location, PV orientation, electricity rate structures, and customer types.

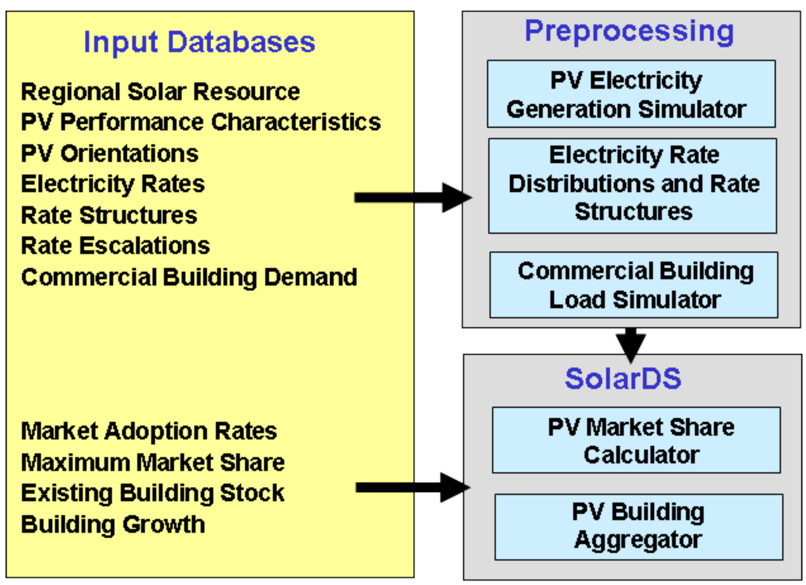

Figure 2. PV annual value preprocessor

[2] SolarDS has the capability to run through 2050, but this option requires users to extrapolate PV cost reductions, electricity rates, and rate structures from 2030 through 2050.

2.1 PV Performance Simulator

The PV technical performance simulator estimates the amount of electricity that a PV module of a given size will generate each hour, at hundreds of locations in the continental United States, and for a variety of module orientations (multiple tilt and orientation angles). Figure 3 is a simplified diagram of the simulation process for generating PV performance libraries.

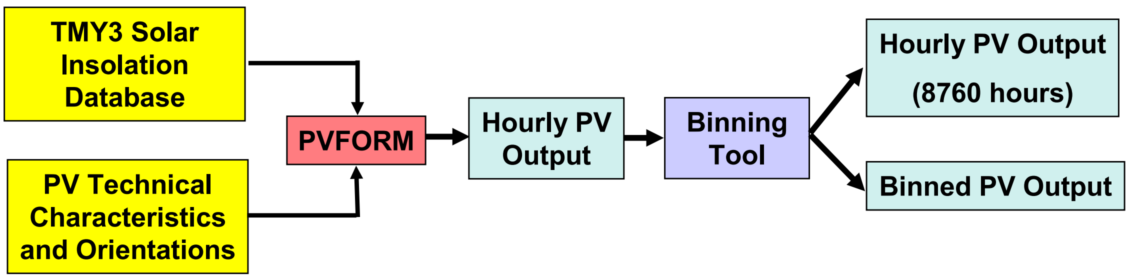

Figure 3. PV energy output calculator

The amount of electricity generated per 1 kW of PV capacity is calculated using hourly solar insolation data from 216 locations in the Typical Meteorological Year 3 (TMY3) data set[3] from the National Solar Radiation Database (NSRDB) (NREL 2007, Wilcox and Marion 2008). The amount of AC electricity generated by a given amount of PV capacity at each location and module orientation is calculated using the PVFORM/PVWATTS model,[4] which includes direct current (DC) to alternating current (AC) derate factor and a temperature-based parameterization of PV efficiency (Marion et al. 2005). TMY3 stations are associated with adjacent census blocks, which are defined as solar resource regions in SolarDS as shown in Figure 4. Further information on PV module derate factors, orientations and the location of TMY3 sites is provided in Appendix A.

[3] The 216 locations chosen for this analysis are, with a few exceptions, the stations in the original 1961-1990 NSRDB. Although the updated (1991-2005) NSRDB contains several hundred additional sites, the 216 original sites provide adequate coverage to capture the variation in solar resource within each state. For additional detail about the NSDRB, refer to *NREL* (2007).

[4] *PVFORM* is the PV performance model used in the *PVW*atts tool. PVFORM accounts for changes in module efficiency with temperature and the variation in inverter efficiency as a function of load. Additional details are available at http://www.nrel.gov/rredc/pvwatts/.

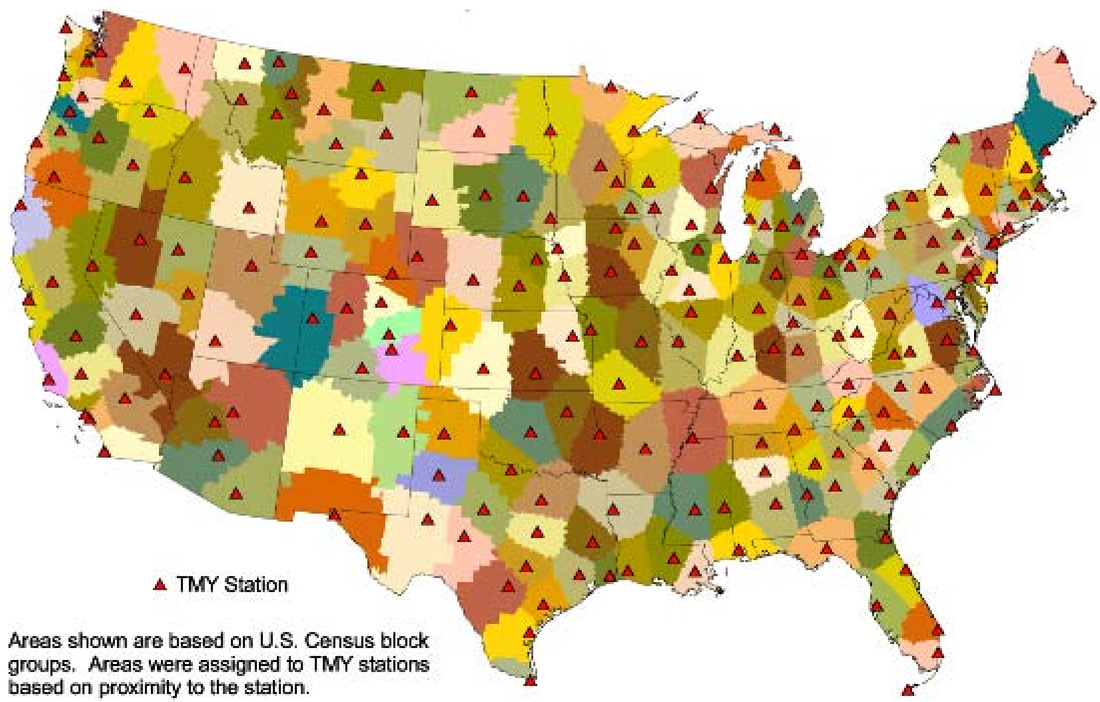

Figure 4. The 216 TMY3 sites used in SolarDS and associated solar resource regions

The hourly PV simulations are archived in a PV performance library that is used by the Annual Revenue Calculator.

2.2 PV Annual Revenue Calculator

The PV Annual Revenue Calculator combines the PV technical performance, electricity rates and rate structures, and building load simulations to create the expected annual savings associated with a specific PV system.

Annual revenue is calculated for each unique combination of TMY site, electricity price region, rate structure, and orientation. The combination of TMY site and electricity price region is defined as a SolarDS region. There are 435 unique SolarDS regions in the United States. The definition of a SolarDS region is demonstrated in Figure 5, which shows TMY3 sites for New York state.

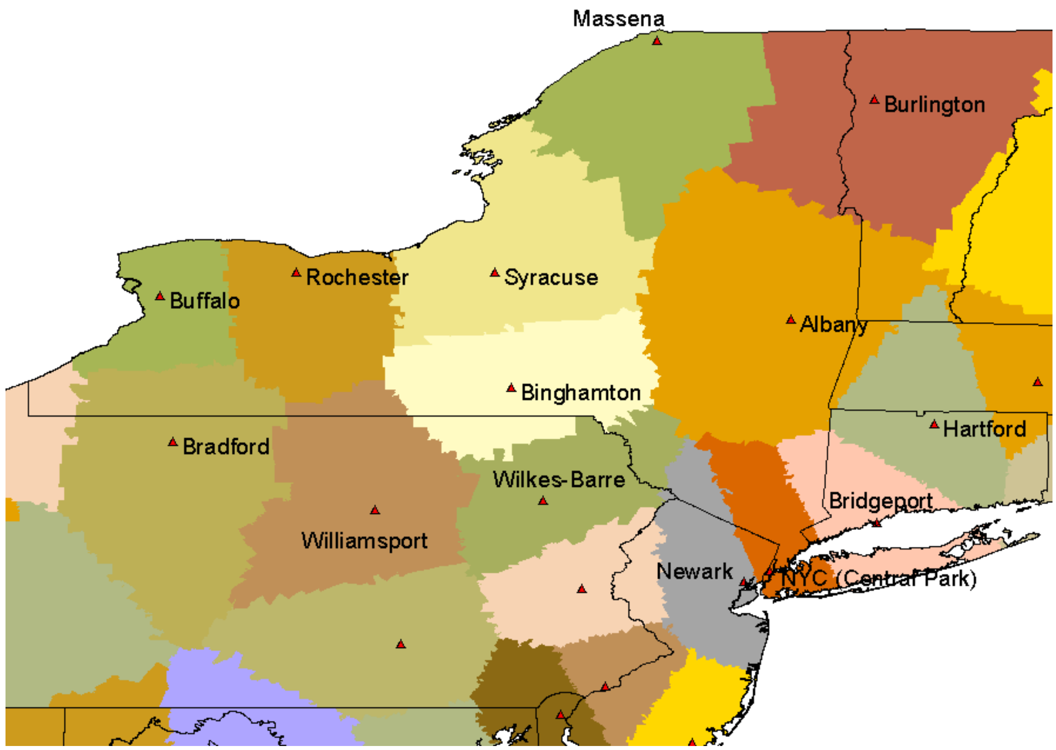

Figure 5. SolarDS regions in New York

The most appropriate TMY site is not always located within a state's borders. For example, a consumer evaluating potential PV system performance in far northeastern New York would likely use the insolation data for Burlington, Vermont. To calculate the financial performance of a PV system in northeastern New York, a combination of New York electricity rates and a TMY site in Vermont would be used. For the state of New York, 14 TMY sites (7 internal and 7 external) are combined with the state's electricity rates, resulting in 14 SolarDS regions. At the national level, the unique combinations of TMY sites and state-based rate structures results in 435 SolarDS regions.

Figure 6 illustrates how the SolarDS calculates the annual PV revenue for each simulated PV system. Annual PV revenue is calculated as the avoided cost of electricity, or the amount the customer would have paid the utility without the PV system.

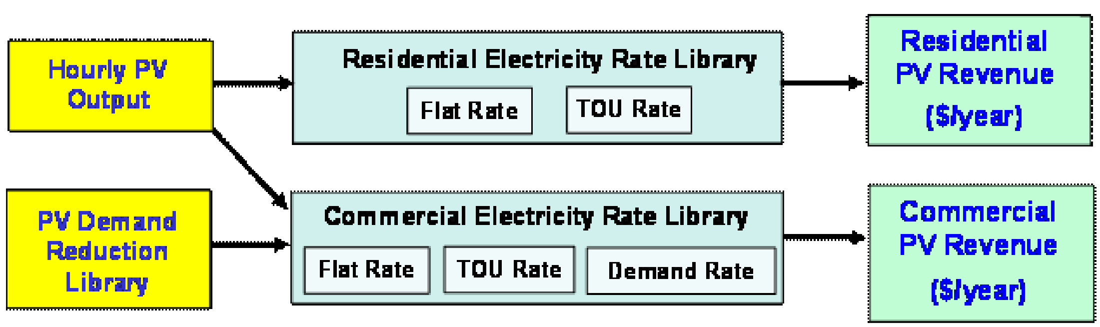

Figure 6. Annual PV revenue submodule

The revenue generated by a PV system is calculated by multiplying the hourly PV output by the hourly cost of electricity at each location. The cost of electricity is determined by the rate structure, which may be a flat, time-of-use (TOU) rate or a demand rate (discussed in more detail in the next section).

In SolarDS, the escalation in electricity rates through 2030 is estimated using either the Energy Information Agency's Annual Energy Outlook (AEO) 2009 forecast (EIA 2009a) or a user-supplied escalation scenario. The end product is a database containing the annual revenue generated by a PV system in each unique combination of geographic location, module orientation, rate region, rate structure, and rate escalation scenario.

2.2.1 Treatment of Basic Rate Structures

The large variation in electricity rates and rate structures used by U.S. utilities is challenging to capture in national end-use models. The average retail price of electricity can vary significantly both within and among states. Regional variation in electricity prices can significantly impact the simulated adoption rate of PV. For example, using the average of electricity rates for each state would underestimate PV adoption because of the non-linear relationship assumed between PV revenue/cost and customer adoption rates (sections 3.2-3.3). Capturing early adopters in this manner is especially important when calculating learning based cost reduction[5] (discussed later in section 3.1 and appendix B).

Most residential customers in the United States are billed based on flat or seasonal flat rates. However, time-of-use (TOU) rates are offered for an increasing number of customers, and TOU rates may increase the value of PV to many consumers (Hoff and Margolis, 2004; Mills et al. 2008). TOU rates establish two or three billing periods within each day (on-peak, off-peak, and "shoulder") and may include two or three demand "seasons" (summer, winter, and spring/fall), leading to a total of four to nine rate periods.

Another common rate structure combines one of three basic rate structures (flat, seasonal flat, or TOU) with "block" or "tiered" rate structures. Combinations of structures like these charge a different amount for electricity based on the quantity used. Increasing block/tiered rates are most common in California's investor owned utilities.

SolarDS simulates the availability of several rate types as well as the regional variation in electricity costs. SolarDS establishes a base rate, flat rate, and TOU rate for 53 price regions, based on the current tariff sheet from the largest utility in that region. The price regions include all 48 continental U.S. states and D.C., with California and Nevada split into two regions (north and south), and New York separated into three regions (New York City, Long Island, and the rest of New York). Appendix A provides a list of the SolarDS utility regions and representative utilities. Once the base rates are determined, a distribution of electricity rates for residential and commercial customers in each region is generated.

[5] To characterize the cost reduction of a manufactured good with cumulative amount produced, we use a learning- or experience-based parameterization. Historic PV prices show a range of price decreases from 17 to 26% with each doubling in manufactured PV capacity (Nemet 2006). The NEMS model uses a learning rate that is approximately 13% (EIA 2008a).

This distribution consists of five rate bins, representing the range of electricity prices in each region and the fraction of customers in each rate bin. This range is derived from the EIA form 861 data set, which provides total revenue and total sales for each electricity service provider in the United States.[6] Creating a distribution based on average revenue assumes that the rate structure for the remaining utilities is essentially the same as the largest utility, which roughly captures the price difference for utilities in the state.[7]

Modeling tiered rates is difficult because PV installations reduce electricity use at the marginal tier. Tiered rates can exceed 30 cents/kWh for residential customers in the highest tier, but only a fraction of customers will consume a substantial amount of energy at that tier. Many customers in California pay for electricity using tiered rates that are roughly captured by the wide spread in the electricity rate distributions in California.

Figure 7 illustrates the distribution of residential electricity rates within each state and the differences among states.

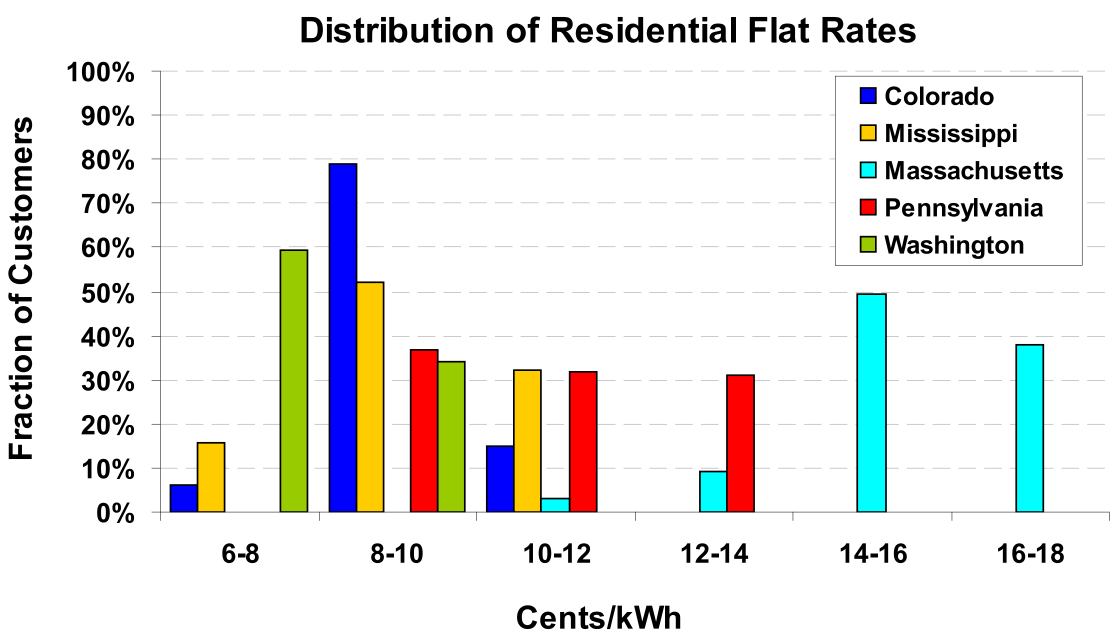

Figure 7. Distribution of residential flat electricity rates in five states

SolarDS offers several options for treating net metering. The user can choose a full net metering option where surplus PV generation (output that exceeds building load) is sold back to the utility at retail rates. Alternately, the user can choose a no net metering option where a fraction of the PV electricity is assumed to be used by the customer when it is produced and valued at retail electricity rates (as it directly offsets electricity purchases), and the remaining PV generation is exported to the grid and sold at “avoided costs.”

[6] Ideally, utility-level data for 2008 would be used. Because they were not available, the state average 2008 escalation was applied to 2007 utility data.
[7] This method could not be used to evaluate a single PV system, but it does capture general trends.

Avoided costs are generally equal to the cost of avoided fuel use and can be set at the prevailing cost of natural gas generation (which is typically at the margin during hours of peak PV output) or equal to the cost of the fuel for the average generation mix for each state (EIA, 2009b).

The escalation in electricity prices from 2008 through 2030 is approximated using residential and commercial rates escalations from the Annual Energy Outlook 2009 (EIA 2009a), which are estimated at the census level. Alternatively, SolarDS users can specify different rate escalations at the state level to capture different future scenarios.

2.2.2 Simulation of Demand Rates

Small commercial customers are often charged on flat and TOU rates and are captured in SolarDS using the same method as residential customers. However, many large commercial customers are billed based on demand rates which charge for both the amount of energy use ($/kWh) and the amount of peak power use ($/kW peak demand). The value of PV in a demand rate is the sum of two components: the value of reducing peak demand each month and the value of electrical energy generated by the PV system (Mills et al. 2008). The demand reduction value is calculated for each building type by multiplying the building-specific reduction in peak load demand by the demand charge of a representative utility for each state. The PV energy value is calculated for flat or TOU rates, depending on the representative utility rate structure.

PV demand reductions are calculated by simulating hourly load profiles for a range of commercial buildings types. First, a commercial building load library was generated based on 22 "benchmark" commercial building types that were simulated using EnergyPlus[8] (Griffith et al. 2008). EnergyPlus models energy use in buildings, including heating, cooling, ventilation and lighting loads. The load profiles for these benchmark building types are associated with the 14 building types in the EIA's Commercial Buildings Energy Consumption Survey (CBECS) database (EIA 2003), which are described in detail in Appendix C. Hourly load profiles for these 14 building types are simulated in each of the 216 solar resource regions to derive a "normal" building load profile for a total of 3024 unique building type/location combinations. To evaluate the potential demand reduction from PV, the hourly building load simulations were combined with hourly PV output. Both the EnergyPlus building simulations and PV simulations use the same weather data, which allows us to capture the coincidence of weather driven electricity demand and solar resource availability. To increase simulation speed and limit data requirements, hourly data were used in all simulations. As a result, the SolarDS model does not capture short-term fluctuations in PV output (e.g. passing clouds) that could significantly impact demand charges. Demand-responsive controls (e.g. solar load controls) could mitigate most of these impacts, even if they are only installed on HVAC components (Hoff et al 2007).

The end product of the PVFORM and EnergyPlus simulations is a library of peak demand reductions for commercial buildings. Figure 8 illustrates the process of generating the demand reduction library.

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[8]EnergyPlus is a publically available model that can be downloaded at http://www.energyplus.gov/.

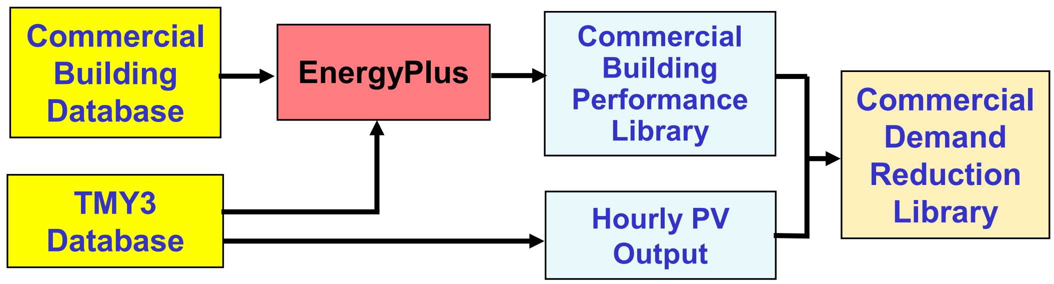


Figure 8. Commercial demand reduction calculator

Figure 9 demonstrates the demand reduction output for four building types. The general pattern of PV demand reduction is similar for most buildings and locations. Summer building peak loads are primarily driven by air conditioning demand, and PV reduces peak demand by 20%-60% of its installed capacity. Demand reduction is not 100% because of the 2-4 hour difference between solar peak (around 1 p.m. Daylight Saving Time) and thermal peak (around 3-6 p.m. DST). As a result, a 10-kW PV system can be expected to reduce peak demand by 2-6 kW. Winter building loads are primarily driven by heating and lighting that are not coincident with peak PV output. During winter months, PV frequently reduces peak demand by less than 10% of its installed capacity.

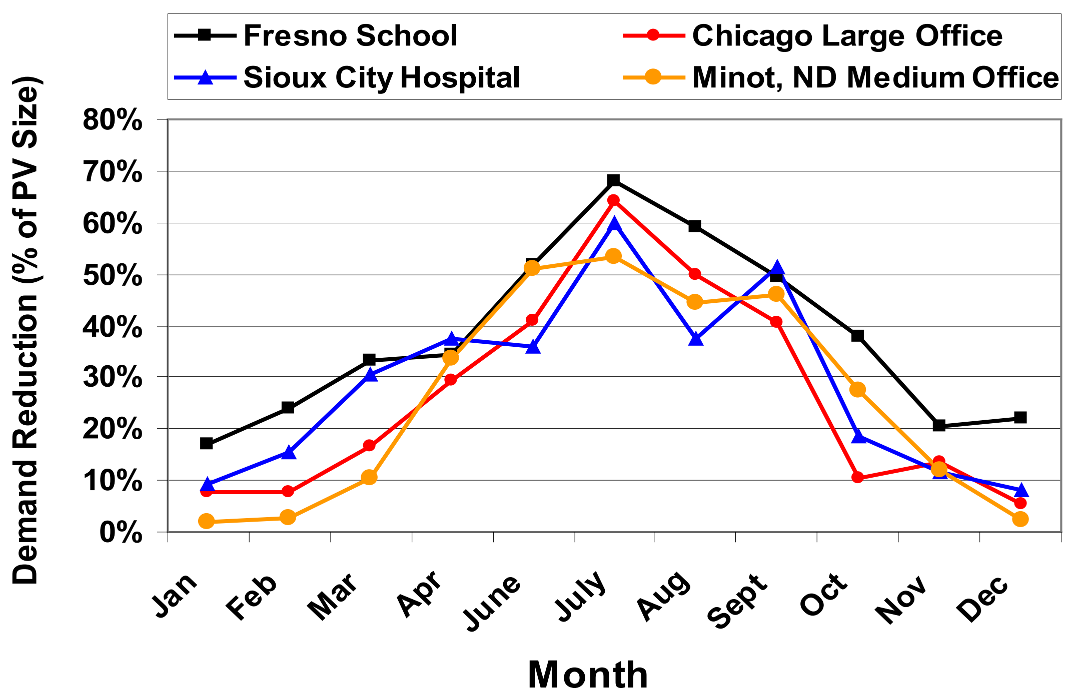


Figure 9. Monthly building demand reduction for various locations in the United States

2.2.3 Value of Avoided Carbon Emissions

SolarDS allows for the potential impact of a carbon constraint and corresponding increase in the price of retail electricity.[9] Since the future price of carbon is highly uncertain, the reference SolarDS model does not include a price for carbon emissions. However, users can specify the price of carbon emissions (\$/ton CO_2) at each two-year model time step. Users have three options for estimating the carbon intensity of displaced electricity. They can: (1) set a carbon intensity based on the local mix of fuels used to generate electricity,[10] (2) select a carbon intensity based on natural gas generation, which is frequently at the margin when PV output is highest (Denholm et al. 2009), or (3) set the carbon intensity for each state based on other criteria. These options allow users to quantify the sensitivity of PV adoption to multiple carbon price scenarios.

3 PV Market Share Module

The main SolarDS module simulates the market adoption of PV in each SolarDS region, based on the price of PV systems, the revenue generated by PV systems, and system financing parameters. SolarDS first generates financial metrics of PV performance from PV cash flows over a fixed analysis period. SolarDS then simulates the decision-making process used by potential PV customers. The time-to-net positive cash flow metric is used for residential customers, and internal rate of return (IRR) is used for commercial customers. These financial metrics are used to estimate the maximum potential PV market share and the rate of PV adoption. Figure 10 illustrates the three submodules that calculate PV cash flows, simulate PV market share and adoption rates for each region, and aggregate the regional results to state and national PV market adoption rates.

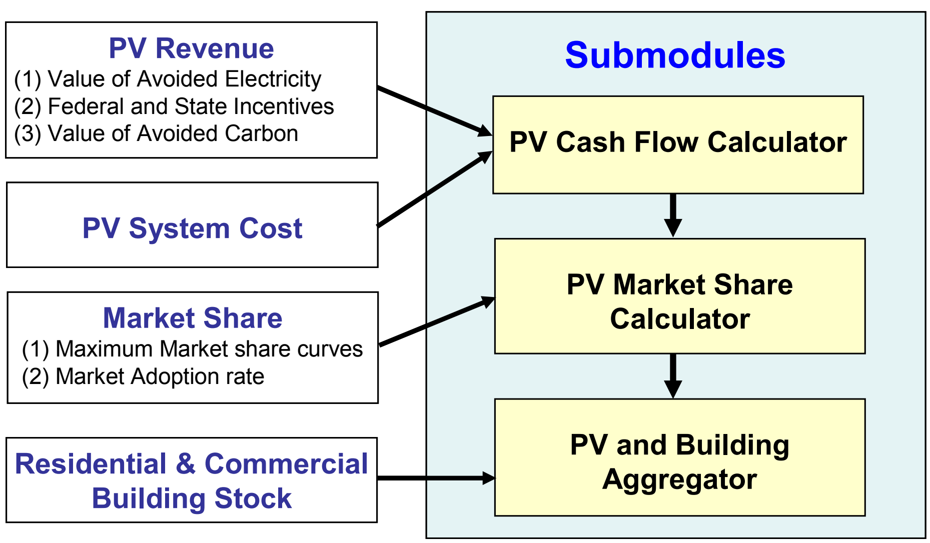


Figure 10. Overview of computational steps involved in the PV market share module

[9] A price for carbon will increase the price of electricity generated using fossil fuels, which will increase the value of avoided electricity purchases.
[10] Carbon intensity for each state is adapted from *Paidipati et al*. (2008) based on the EIA AEO 2007.

3.1 PV Costs

The total cost of a PV system is the sum of the initial cost of the unit (module, inverter and installation fees) plus the variable cost incurred for operation and maintenance (O&M). Substantial PV cost reductions are expected in the future. However, estimates for these cost reductions are highly uncertain. SolarDS users can characterize PV costs over time in three ways. They can: (1) choose PV cost reductions based on the EIA projections (EIA 2009a) or the SETP targets (DOE 2008); (2) specify their own PV cost trajectory; or (3) choose learning-based cost reductions where the cost of PV is reduced by the user-specified rate for each doubling of cumulative installed PV capacity. In the literature, historical PV learning rates range from 17% to 26% (Nemet 2006). SolarDS users can specify different learning rates for each 2-year model time step to characterize evolving market dynamics as the PV industry matures. PV cost projections (EIA and SETP targets) and learning-based cost reductions are discussed in more detail in Appendix B.

Larger PV systems typically have lower costs per unit of capacity (Wiser et al 2007), and SolarDS simulates this decrease in PV cost with system size for both commercial and residential PV systems. Residential PV costs ($/kW) are based on 4-kW PV systems and adjusted by 2% per kW for larger or smaller systems (a 3-kW system is 2% more expensive and a 5-kW system is 2% less expensive than a base 4-kW system per unit of capacity (Wiser et al. 2007)). SolarDS assumes a distribution of residential PV installation sizes ranging from 1 to 6 kW, with mean PV installation sizes of 3.7 kW and 3.0 kW for pre-existing detached and attached single-family homes and 4.25 and 3.2 kW for new detached and attached single-family homes. Mobile homes are assumed to have an average PV installation size of 1.7 kW. For commercial buildings, the base PV cost represents a 300-kW PV installation and the price is adjusted by 0.02% per kW[11] for larger and smaller installations. Since PV systems installed on new buildings typically cost less than systems installed on existing buildings, SolarDS allows the user to set a cost premium for PV on new buildings. In the reference case, PV is assumed to be 10% less expensive on new buildings.

3.2 Federal and State PV Incentives

Many PV incentives are available, including the federal investment tax credit (ITC), state incentives and local incentives at the municipal and utility levels. Incentives can be broadly categorized as capacity-based and production-based. Capacity-based incentives are based on the size or cost of the PV system. Production-based incentives are based on the amount of electrical energy (kWh) a PV system generates. SolarDS includes both capacity-based and production-based incentives at the federal and state levels. In a few states (e.g. Colorado), state-level incentives are not offered, but utility incentives are available to more than 50% of the population. These utility-level incentives are included as state-level incentives in SolarDS, but they are capped by their budgets and expiration dates.

PV incentives are implemented in SolarDS to achieve two design goals: (1) to accurately characterize the current federal and state PV incentives for reference case simulations,

[11] For example, a 200-kW PV system will be 2% more expensive per kW than a 300-kW PV system.

and (2) to allow users to simply and intuitively adjust incentive amounts, durations and budgets to quantify the impact of a wide range of potential incentive scenarios. SolarDS includes federal and state PV tax credits, state rebates, state production-based incentives, and the option to include federal production-based incentives, as discussed below.

1. **Federal tax credits.** The federal investment tax credit (ITC)[12] is included in SolarDS. This 30% tax credit has no residential or commercial cap and expires in 2016. After 2016, we assume a 10% commercial tax credit but no residential tax credit. Users can either run SolarDS with the current ITC or adjust the incentive amount, expiration date, or incentive cap.
2. **Federal production-based incentive.** Although there are no federal production-based PV incentives, the user can add a federal production based incentive to quantify the impact of various incentives. A federal solar production tax credit (PTC) would be analogous to the incentives currently for wind generation. SolarDS users can set the incentive amount ($/kWh), duration, and expiration date.
3. **State tax credits.** State PV tax credits range from 15% to 100% of installed system costs. Incentive caps vary widely by state and the type of installation (residential or commercial). State-level incentives were characterized using the DSIREUSA database[13] and the information provided by each state. In the reference case, state tax credits are applied until their legislated expiration dates if they are specified or until 2014 if they are not specified. As with the other incentives, user can adjust incentive parameters, including whether the state budget allocation limits the incentives, or whether budgets will be expanded.
4. **State rebates.** State rebates are capacity-based incentives similar to state tax credits. As with state tax credits, we include the most current existing state rebates, but users are allowed to adjust incentive parameters as specified above.
5. **State production-based incentive.** Production-based incentives are based on the amount of electrical energy generated. This production-based revenue is added to the net revenue of the PV system in the year it is generated.

The cost of both federal and state PV incentives is calculated for residential and commercial installations at each time step. The amount of money spent on incentives is tracked and compared with the budgets allocated for PV incentives at the state level. Tracking the money spent also enables users to quantify the relative impact per dollar spent for different incentives.

[12] The Energy Improvement and Extension Act of 2008 (EIEA), passed in October 2008, extended the 30% PV Investment Tax Credit through 2016, lifted the cap on residential PV installations, allowed utilities to use the ITC, and allowed customers to apply the tax credit against the alternative minimum tax (AMT).
[13] Incentives and incentive caps are adapted from http://www.dsireusa.org/.

3.3 Cash Flow Calculator

PV installations require a large initial capital investment that is followed by operation and maintenance costs. The initial capital expenditure is generally financed, and the SolarDS model projects multiyear cash flows to generate financial performance metrics.

Many financial performance metrics are available, including payback period (simple or discounted), net present value, cost to benefit ratio, and the levelized cost of electricity. The metric used in a given analysis depends largely on consumer types. Residential customers may use relatively simple metrics, such as simple payback period, to decide whether to invest in a PV system. Commercial customers may use more sophisticated metrics to account for capital depreciation.

SolarDS model users can specify the loan rate, loan term, and down payment fraction for financing PV systems. SolarDS uses the combination of PV cost and revenue to: (1) generate different financial performance metrics for residential and commercial systems, both of which were adopted from the NEMS model, and (2) simulate the different decision-making process used by the different customer types. Residential systems use the time-to-net positive cash flow metric (LaCommare et al. 2003), which represents the first year that the revenue generated by the PV system exceeds the costs of ownership. Commercial systems use the internal rate of return (IRR) (EIA 2008a), which is equivalent to the discount rate that makes the net present value of PV cash flows equal to zero. The IRR metric is likely used to analyze the cost effectiveness of PV on commercial buildings. The IRR metric also better captures the value of PV with oscillating positive and negative cash flows, based on the accelerated capital depreciation schedule for renewable energy technologies.[14] The details of these calculations are outlined below.

The method for calculating time-to-net positive cash flow for residential systems is based on an annual cash flow analysis. The initial cash flow is given by the down payment on the PV system. The loan amount is given by the PV system cost minus relevant state rebates and federal and state tax credits. The annual loan payment is calculated from the loan amount using the uniform capital recovery factor (UCRF) given by

UCRF = $\frac{r(1+r)^n}{(1+r)^n - 1}$, where r is the interest rate and n is the loan term in years. The following summarizes the cash flows in the initial year. Loan amounts and loan payments are calculated using the following equations:

$$\text{Loan Amount} = \text{PV System cost} - \text{Down payment} - \text{Federal and State Tax Credits \& Rebates} \quad (1)$$

$$\text{Loan Payment} = \text{Loan Amount} * \text{UCRF} \quad (2)$$

Residential systems are financed using a distribution of down payment fractions (Appendix D) to capture a range of financing options. Users can modify both residential

[14] Capital depreciation for renewable energy systems follows the five-year Modified Accelerated Cost Recovery System (MACRS) schedule.

and commercial down payment fractions. With these options, users can characterize both systems that are not financed (100% down payment) and the impact of new financing options (Fuller et al., 2009). For financed PV installations, the annual loan payment is calculated following equations 1 and 2 above.

Fixed incentives are subtracted from the initial PV system costs. Fixed incentives are generally onetime payments, such as federal or state investment tax credits or system buydowns (rebates). Buydowns, which are available in the form of state or utility credits, are subtracted from the initial purchase price. The base case assumes that state-level tax credits are federally taxable;[15] however, state and utility-level buy downs are not considered taxable income.

Annual cash flows for PV systems are used to calculate both the time-to-net positive cash flow and IRR metrics. We set the PV cash flow at year zero to be the down payment assumed for the system. In subsequent years, the annual cash flow is calculated from the sum of avoided electricity costs, tax savings on loan interest, state production incentives, avoided carbon costs (if there is a charge for carbon emissions in the future) minus the loan payment and annual operation and maintenance fees:

Year 0:

Annual Cash flow(t=0) = - Down Payment (3)

Years 1-30:

Annual Cash flow(t) = Avoided Electricity Costs
+ tax savings on the loan interest
+ State production-based incentives
+ avoided cost of carbon emissions
- Loan Payment
- Operations and Maintenance costs (4)

The tax savings on the loan interest is given by:

$$\text{Interest deduction}_y = \text{Marginal Tax Rate} * r * \text{Loan Principal}_y \quad (5)$$

where *r* is the interest rate. Production-based incentives are often available at the state and utility level and are added to the PV cash flow in the years they are earned. The Operations and Maintenance costs are primarily based on inverter replacement. Inverter costs and lifetimes are based on SETP targets and Wiser et al. (2009) and inverter replacement costs are subtracted from PV cash flows in the year they are replaced.

Residential cash flows are calculated for 30 years. If the net cash flow becomes positive, the payback period is calculated by interpolating over the last time period to find the fractional number of years to reach net positive cash flow. If the net cash flow remains negative through the 30-year analysis, the payback period is set to 30 years, which results in zero market penetration. Figure 11 illustrates the process of calculating the time-to-net positive cash flow metric for residential systems.

15 State buydowns reduce customers' state tax burdens, which are tax deductable at the federal level.

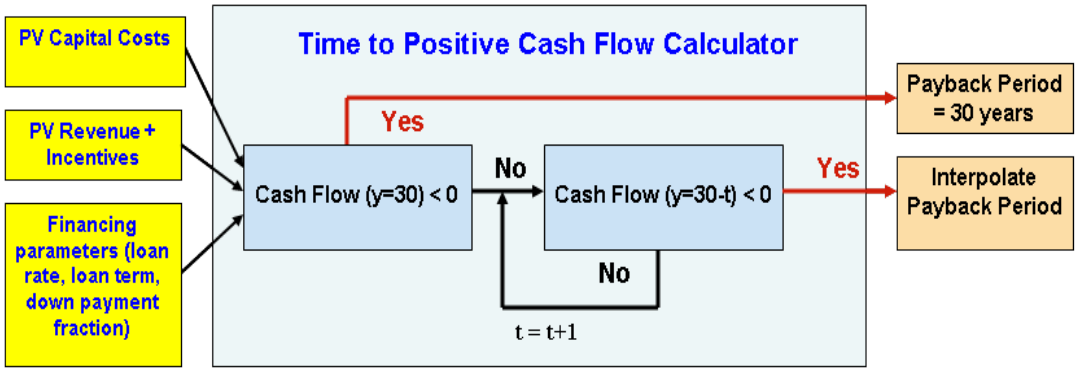


Figure 11. Time-to-net positive cash flow calculation

To calculate the payback period for commercial PV installations, we first separate potential customers into for-profit and not-for-profit categories. With not-for-profit buildings, where cash flows are similar to residential buildings with tax considerations removed, a similar time-to-net positive cash flow simulation was run. With for-profit buildings, customers have more complicated tax structures that include capital both depreciation of PV systems and tax deductable energy and O&M costs. These additional tax considerations often lead to net cash flows that oscillate between positive and negative values over the analysis period, making the time-to-net positive cash flow metric difficult to interpret. We account for the following four tax impacts for commercial PV customers:

- PV system costs are depreciated, decreasing the tax burden according to the depreciation schedule. SolarDS uses the Modified Accelerated Cost Recovery System (MACRS) schedule.
- Since electricity expenses are tax deductible, the net annual savings from a PV system is reduced by the marginal tax rate.
- The interest on a PV system loan is tax deductable.
- Operation and maintenance (O&M) expenses are tax deductible.

To calculate the payback period for PV installations, we use the internal rate of return (IRR) metric for commercial for-profit customers. IRR is the annualized effective rate of return that can be earned by investing capital in a PV system, and is calculated from the annual cash flow generated by a PV system. At year zero, the cash flow is negative and equal to the down payment for the PV system. In each subsequent year, cash flow is calculated by the sum of PV revenue, loan payments, and tax credits. This calculation is similar to the calculation in equations 1 to 5 but with added tax considerations. IRR is calculated by finding the equivalent rate of return necessary for the PV system to have a net present value (NPV) of zero:

$$NPV = \sum_{t=0}^{N} \frac{C_t}{(1+IRR)^t} = 0 \qquad (6)$$

where C_t is the annual net revenue of the PV system in year t. Following the methodology used in the NEMS commercial distributed generation module, we derive a simple payback period (T) for a PV system by calculating the time required for capital to double in value while appreciating at the annualized IRR (EIA 2008b).

$$(1+IRR)^T = 2 \tag{7}$$

$$T = \frac{\log(2)}{\log(1+IRR)} \tag{8}$$

IRR is translated into payback time because the market adoption curves used by NEMS and many other studies are "calibrated" to payback time (Kastovich et al. 1982, Paidipati et al., 2008; R.W. Beck, 2009). We cap the maximum payback time (T) at 30 years, which results in zero PV market penetration.

While IRR is likely a better metric for simulating the decision process for installing commercial PV systems, the IRR of a system is often difficult to interpret. Since PV incentives are highest in the first few years of ownership (e.g. tax rebates, buydowns and accelerated depreciation), a financed system will frequently have positive cash flows in the first five years followed by negative cash flows. This can lead to a circumstance with very high IRRs that significantly discount the negative cash flows following the accelerated depreciation schedule.

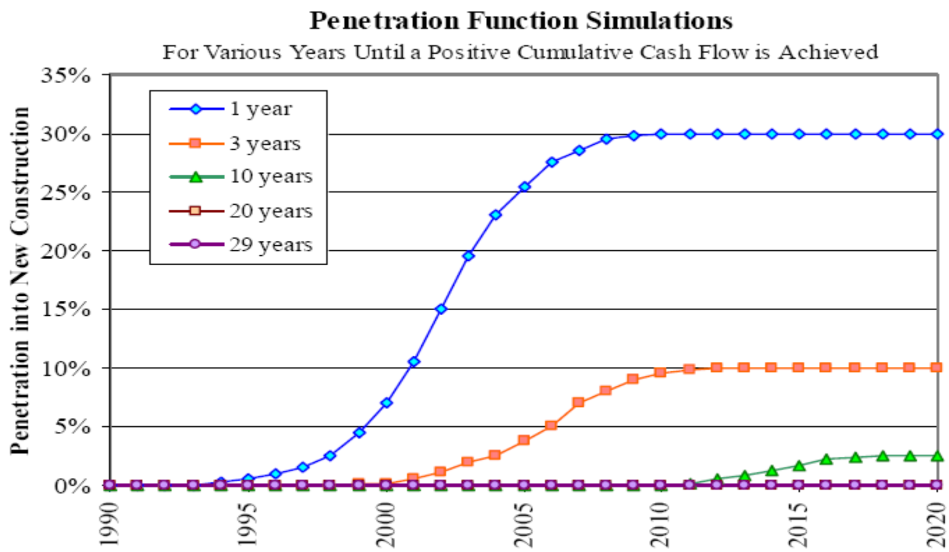
Both payback calculations require a number of inputs, including PV capital costs, O&M costs, and various policy-based incentives. The base case assumptions for these values are described in section 4, along with user-defined options for adapting the model to additional run scenarios.

3.4 Market Share Calculator

Forecasting PV adoption by end users based on the financial performance of a PV investment is perhaps the most subjective aspect of any market-penetration model. The model must simulate both the ultimate fraction of customers[16] that will adopt PV technology and the rate of customer adoption. Considerable literature exists on this subject; however, solar PV has unique characteristics that differentiate it from many of the products and services examined in market-penetration studies. As a result, there is considerable uncertainty about which consumer behavior studies are applicable to solar PV adoption.

Most market-penetration models use a "market diffusion" or "S-curve" model that simulates the rate of market adoption over time. The general characteristics of an S-curve model are shown in Figure 12, which illustrates the annual adoption rate as a function of payback time and diffusion rate used in the NEMS model for PV systems on new buildings (EIA 2008a).

[16] A 'customer' refers to the occupant of a building that is suitable for PV adoption as described in section 3.5.



Source: Adopted from LaCommare et al., 2003

Figure 12. Market share as a function of payback period used in NEMS

The curves in Figure 12 represent different payback periods, where products with a quicker payback time achieve a higher market share and have faster adoption rates. Market-penetration is simulated in the NEMS model by the product of the maximum market share and the adoption rate, expressed as follows:

$$\text{PV Market Share(PV payback time, time)} = \text{Max Market Share(PV payback time)} * \text{Adoption Rate(time)} \tag{9}$$

SolarDS uses a similar dynamic market share calculator that is based on an S-Curve market diffusion model. PV market share is calculated by the product of the maximum market share (which is approximated using an empirical relationship to payback time) and the rate of adoption (which is approximated using a Bass diffusion model [Bass 1969, Mahajan, et al. 1990]). Figure 13 illustrates the computational steps in the market share module.

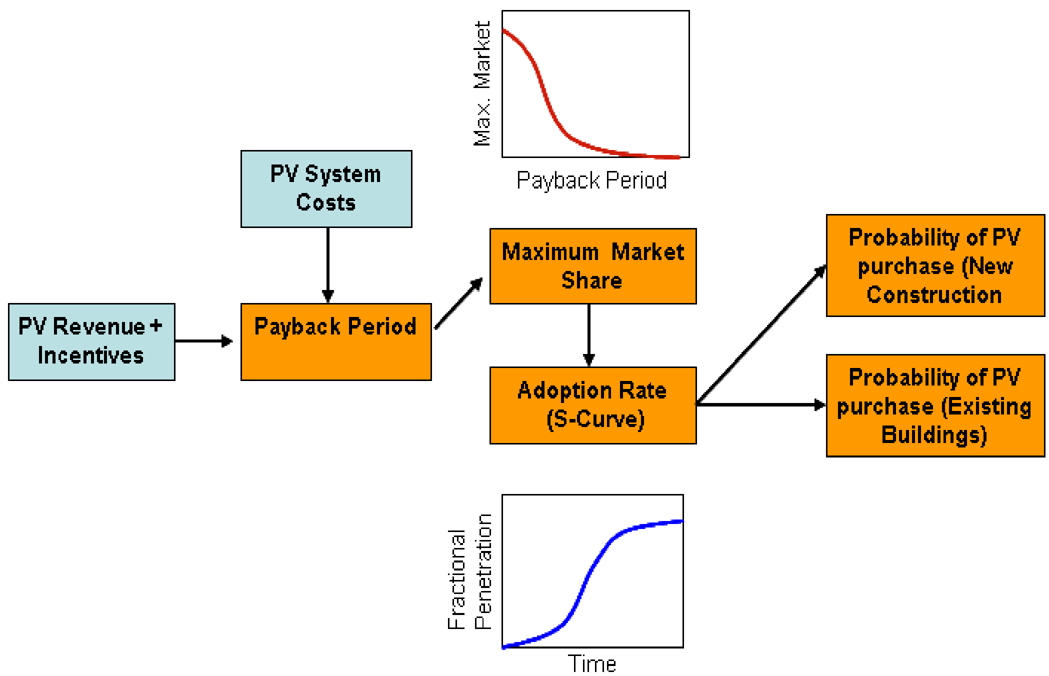


Figure 13. Computational steps involved in the market share module

SolarDS users have three options for characterizing the maximum market share as a function of payback time: (1) use the NEMS maximum market share curves (EIA 2004), (2) use the Navigant Consulting, Inc. curves (Paidipati et al. 2008), or (3) supply user-defined maximum market share curves. Each method has different maximum adoption curves to capture the different market dynamics for new and existing buildings. User-defined curves are calculated using an exponential fit (R.W. Beck 2009), defined as follows:

$$Maximum\ Market\ Fraction = \mathrm{e}^{-Payback\ Sensitivity\ *\ Payback\ Time} \tag{10}$$

The *Payback Sensitivity* variable determines the shape of the maximum market fraction curve and can be set by the user to characterize different PV market dynamics and conduct sensitivity analysis. A value of 0.3 has been used previously (R.W. Beck 2009) to fit the mean of two market adoption curves (Kastovich et al. 1982, Paidipati et al. 2008). Figure 14 shows the maximum market fraction curves modified from NEMS and Navigant, and a user-defined market adoption curves with *Payback Sensitivity* = 0.3 for commercial and residential customers.

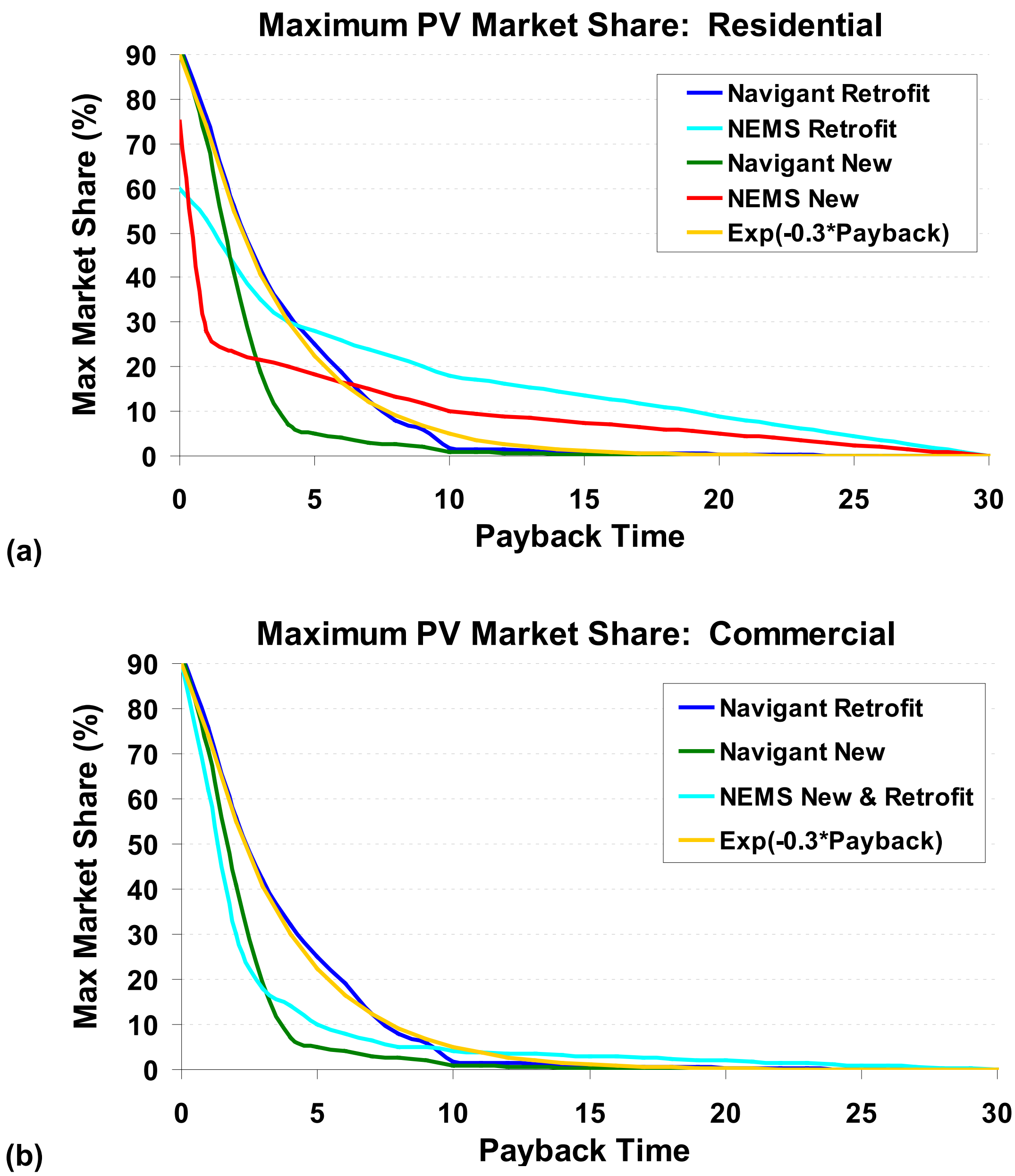


Figure 14. Maximum residential (a) and commercial (b) PV market share expressed as a function of payback time[17]

[17] The minimum payback time allowed in SolarDS is one year.

The rate of PV adoption (S-Curve) is calculated using the Bass-Diffusion model, expressed as follows:

$$\text{Adoption Rate (t)} = \frac{1-e^{-(p+q)\bullet T}}{1+\left(\frac{q}{p}\right)e^{-(p+q)\bullet T}} \qquad (11)$$

where T is the time from the initial year the product was introduced, p represents the "coefficient of innovation" characterizing early adopters of a technology, and q represents the "coefficient of imitation" characterizing late adopters of a technology. We simulate increasing adoption rates with decreasing payback times, as indicated by the three S-curves used in SolarDS that are shown in Figure 15. Additionally, users can modify the p and q parameters to simulate different PV diffusion rates.

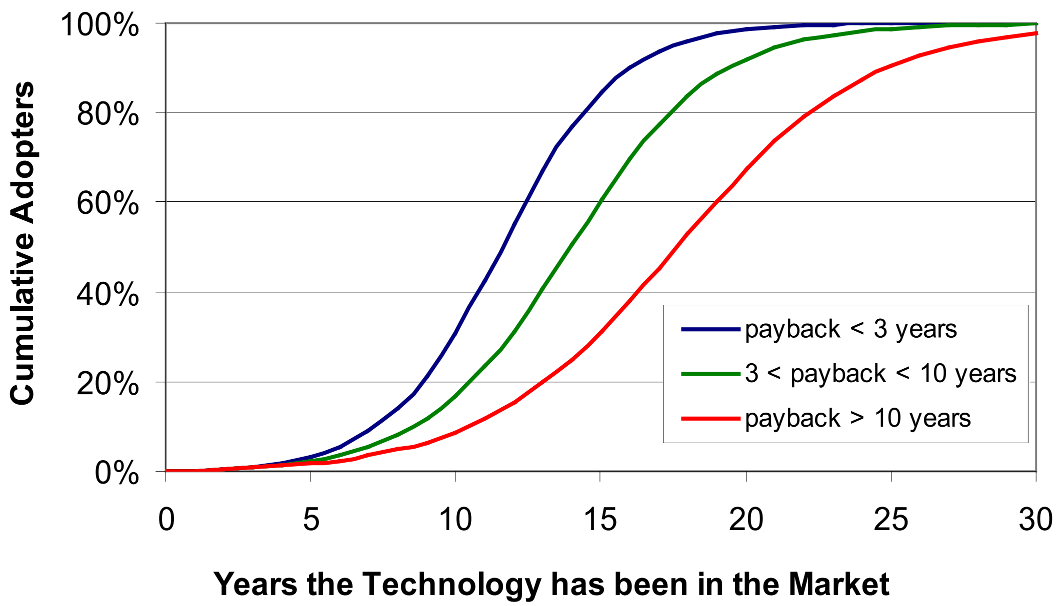


Figure 15. PV adoption rates based on PV payback times and the amount of time PV has been in the market

One complication of using multiple S-curves is transitioning from one curve to another when PV payback periods decrease with PV cost reductions and/or increasing electricity rates. Since the market-penetration fraction scales the total building stock, this transition would lead to a step increase in PV adoption in the year that the model switched from one curve to another. To smooth this transition, we calculate the position on the new S-curve by solving for the "equivalent year" that represents the previous year's market share, shown in Equation 12, which is equivalent to equation 11 solved for T using the previous year's market share:

$$Equivalent\ Year = \frac{ln\left(\dfrac{1-\left(\dfrac{Max\ Market\ Share(t-1)}{Max\ Market\ Share(t)}\right)}{1+\left(\dfrac{Max\ Market\ Share(t-1)}{Max\ Market\ Share(t)}\right)*\dfrac{q}{p}}\right)}{-(p+q)} \tag{12}$$

After the equivalent year is calculated, the model steps forward in time by two years and solves for the total market share using the p and q parameters from the new S-curve. The initial year for the diffusion curves is set to 2001, when the total U.S. installations exceeded 25 MW. The initial year is set to 1999 in California to characterize the quicker adoption rates (Paidipati et al. 2008).

3.5 Calculating building stock and aggregating PV installations

The market share calculator produces an array containing hundreds of thousands of PV purchasing probabilities that are unique to each building type, size, age, utility rate structure, and local solar insolation. To estimate the number of buildings that will have PV installed, PV adoption probabilities must be multiplied by the actual number of buildings corresponding to the combination of input parameters. The number of buildings is calculated in a building stock database that consists of multidimensional arrays that characterize the range of unique buildings types for residential and commercial buildings. This building stock database is populated from a variety of sources.

Residential Building Array

The residential buildings stock for attached and detached single-family homes, mobile homes, and rental units is estimated from the 2000 U.S. Census. The fraction of each building type that is occupied by an owner or renter is estimated using the EIA's 2005 Residential Energy Consumption Survey (RECS) (EIA 2005). The base building stock is scaled down to remove homes that are unsuitable for PV, primarily due to shading. Shading estimates are applied at the EIA's "Census + 4" regions, which includes the census regions plus the four largest states. Data on shading are limited, and the base SolarDS case uses a previous national estimate that is adjusted to increase shading in the eastern United States and decrease shading in the Southwest. Shading fraction assumptions are listed in Appendix C.

The growth rate of residential building stock is forecasted in two-year increments from 2008 to 2030, based on census population projections at the state level. We assume that: (1) the building stock will grow in proportion to the state population, (2) the regional distribution of the population will stay fixed, and (3) the distribution of building types will remain constant.

After simulating the base number of homes suitable for PV, the building stock library categorizes these homes, based on the following seven array dimensions: SolarDS region, building size, roof orientation, finance type, rate type, rate bin, and building vintage.

1. **SolarDS Region.** Census data provide the numbers of detached single-family homes, attached single-family homes, and mobile homes in each state. The states

are then divided into SolarDS regions, based on census blocks. Each census block is assigned to a specific TMY meteorological site. The number of buildings in each SolarDS region is calculated from the fraction of the state population that resides in the associated census blocks.

2. **Building PV Size.** SolarDS calculates a range of residential PV system sizes based on building types, where the "average" size for a residential PV installation is 4.3 kW and 3.8 kW for new and existing detached single-family homes, 3.2 kW and 3.0 kW for new and existing attached single-family homes, and 2.0 kW for all mobile homes. The size distribution is assumed to be uniform in all geographical regions.

3. **Roof Orientation.** We assume a distribution of solar orientations in the SolarDS model. For residential homes, we assume that 10% of buildings have flat roofs and the remaining 90% have pitched roofs characterized by seven solar orientations that are uniformly distributed around 360°. Roof characteristics are assumed to be identical for all geographical regions. A table of roof orientations and distributions is provided in Appendix C.

4. **Finance Type.** SolarDS uses a distribution of down payment fractions and marginal tax rates to characterize the variety of financed residential PV systems (see Appendix D). Users can modify customer down payment fractions, marginal tax rates, loan rates, and loan terms to quantify the sensitivity of PV adoption to various scenarios.

5. **Rate Type.** SolarDS allows users to select from three rate types: all flat, all time-of-use (TOU), and a combination of flat and TOU rates that changes over time to reflect the gradual adoption of TOU rates. The "all flat" and "all TOU" options are provided to test the sensitivity of PV deployment using the two rate structure bounds.

6. **Rate Bin.** SolarDS splits residential customers into five rate bins in each region to characterize the distribution of customer rates, as discussed in section 2.2.

7. **Vintage.** The cost of PV installations on pre-existing buildings is higher than the cost of PV installations on new construction. SolarDS allows users to specify the relative cost reduction for new buildings, which in the reference case is set to 10%. New and existing buildings also use different maximum market-penetration curves, reflecting the different decision process made by the builder and homeowner. Existing buildings are calculated from the census data, as described above. New construction is primarily driven by the growth in building stock but also from rebuilds.

Rental properties represent a large fraction of commercial and residential buildings. This significantly limits the use of solar PV. Building owners, who do not pay the electric bill, have no incentive to install PV. Renters have limited incentive to make long-term capital investments on property they do not own. The fraction of homes that are rented for attached single-family, detached single-family, and mobile homes are 12%, 34%, and 17%, respectively, as taken from the 2001 Residential Energy Consumption Survey

(RECS) at the EIA's "Census + 4" regions. PV adoption on rental units is simulated separately using decreased market-penetration curves that can be modified by the user.

Commercial Building Array

Creation of the commercial building array begins with the "base" number of commercial buildings in the EIA's 2003 Commercial Buildings Energy Consumption Survey (CBECS) (EIA 2003), allocated for the "Census + 4" regions. To account for roof shading, the amount of roof area is decreased by a regional shading fraction using a similar methodology as was used for residential buildings. Leased units are estimated using a uniform rent/own fraction for each region, based on the CBECS tax status in owned buildings (taxable/non-taxable). PV adoption on leased buildings is simulated using decreased market-penetration curves. This establishes the "base" number commercial buildings suitable for PV, which the building stock library then categorizes based on six array dimensions: SolarDS region, roof orientation, occupant class, building type, rate type, rate bin, and age.

1. **SolarDS Region.** Commercial buildings are allocated to SolarDS regions, based on the fraction of the state population in census blocks associated with TMY stations, as described previously.
2. **Roof Orientation.** Commercial PV orientations are based on the type on the "predominant roof material" of each building type, as reported in the CBECS database. If the reported roof material is shingle, wood, or slate, the roof is assumed to be pitched. For pitched roofs, we assume the same roof slope as residential buildings and the azimuth orientations listed in Appendix C. For the remaining roof types, we assume a flat roof surface filled with equal parts flat oriented PV and southerly facing PV, tilted at 25°. Fewer commercial roof orientations are evaluated than residential roof orientations because of the much larger size of the commercial building stock array.
3. **Occupant Class.** There are four classes of building occupants: for-profit owner occupied, non-profit owner occupied, leased, and government owned. These distinctions are made for three reasons. First, non-profit and government buildings are not taxable. Second, non-profit and government buildings may have a different decision-making process for evaluating PV investment. Finally, leased buildings likely have either a significantly lower market adoption rate or a third-party owner of the PV systems. Ownership data are derived from the CBECS tax status in owned buildings (taxable/non-taxable).
4. **Building Type.** SolarDS uses 14 building types from the Commercial Buildings Energy Consumption Survey database (EIA, 2003). Available roof area for PV is calculated by building type. PV installation sizes are calculated for each building type by scaling the available roof space by the module efficiency (W/ft^2). The types of buildings and associated roof areas are listed in Appendix C.
5. **Utility Rate Class.** SolarDS allows users to select from four rate types: all flat rates, all time-of-use (TOU) rates, all demand-based rates, and mixed rates, which represent a combination of flat, TOU, and demand-based rates. The all flat, all

TOU, and all demand options are provided as benchmarks to test the sensitivity of PV adoption to commercial rate structures.

6. **Vintage.** As with residential buildings, users are given the option to set how much less expensive PV will be on new commercial buildings than on existing buildings. Also, new and existing buildings use different maximum market-penetration curves, reflecting the different decision-making processes followed by builders and owners. New and existing commercial building stock is calculated from census projections, similar to the way in which building stock is calculated for residential buildings.

Based on these assumptions, the total potential PV capacity (technical potential) in SolarDS by 2030 is 583 GW, including 271 GW of residential and 312 GW of commercial PV capacity, which is in line with previous estimates of U.S. rooftop PV capacity (Denholm and Margolis 2008). Using the Navigant Consulting maximum market-penetration curves, the maximum obtainable rooftop PV capacity[18] by 2030 is 425 GW (182 GW residential, 243 GW commercial). Using the NEMS market-penetration curves, the maximum obtainable rooftop PV capacity by 2030 is 225 GW (95 GW residential, 130 GW commercial).

Buildings Aggregator

Once the residential and commercial buildings databases are established, the number of buildings adopting PV is calculated by multiplying the number of buildings in each class by the adoption fraction associated with each class. Figure 16 illustrates general approach for aggregating the new and existing buildings with PV. This process is run separately for residential and commercial buildings.

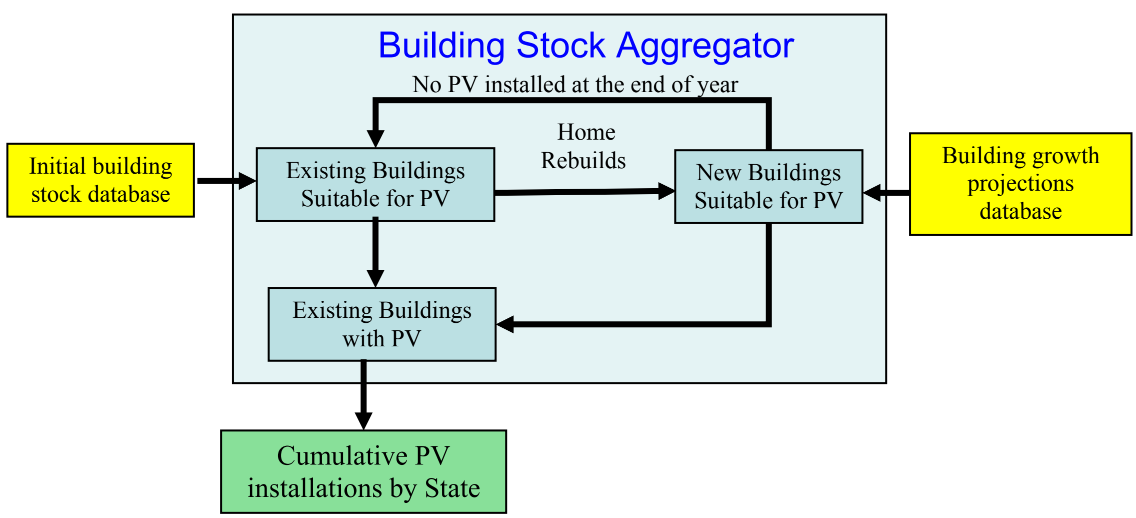


Figure 16. Aggregating buildings with PV

The submodule begins by calculating the existing building stock available for PV for each unique building type. The number of existing buildings with PV is calculated from

[18] Minimum PV payback times are capped at one year in SolarDS due to model resolution.

the product of the fractional market share and the total number buildings in that particular building class.

The model similarly calculates the fraction of new buildings that install PV. The number of new buildings is calculated from the sum of (1) building growth calculated from census population projections at the state level, and (2) building rebuilds, which are assumed to be 1% of the existing buildings per year. The adoption of PV on new buildings is calculated from the product of the number of new buildings and the current adoption rate, calculated by the market share calculator. New buildings that do not adopt PV are then placed into the existing building stock.

The number of buildings with PV is summed over each building type to produce the amount of installed PV capacity (MW), and the fraction of buildings with PV for each state and time period. Total PV capacity (MW) is calculated from the product of the number of buildings that install PV and the size of the PV installation by building type. The state results are further aggregated to give national PV statistics for each time period.

4 SolarDS Results

SolarDS outputs the results of each simulation to a new Microsoft Excel workbook that includes user-defined run parameters saved in a main worksheet and the model output (at the state and national level) in a series of worksheets that include:

1. Annual PV Capacity
2. Cumulative PV Capacity
3. Annual Residential PV Capacity
4. Cumulative Residential PV Capacity
5. Annual Commercial PV Capacity
6. Cumulative Commercial PV Capacity
7. Annual # of Residential Buildings that Installed PV
8. Cumulative # of Residential Buildings that Installed PV
9. Annual # of Commercial Buildings that Installed PV
10. Cumulative # of Commercial Buildings that Installed PV
11. Fraction of Residential Buildings with PV
12. Fraction of Commercial Buildings with PV
13. Annual Cost of Residential Incentives
14. Annual Cost of Commercial Incentives
15. Cumulative Cost of Residential and Commercial Incentives
16. Residential Payback Times (aggregated to the state level)
17. Commercial Payback Times (aggregated to the state level)

The output file also contains an automated plotting tool to help the user quickly visualize SolarDS results.

4.1 SolarDS Example Results

The amount of PV penetration simulated by SolarDS is highly dependent on model input parameters, primarily (1) future PV cost reductions, (2) the assumed maximum PV market-penetration curves as a function of PV financial performance, and (3) PV financing and policy-based assumptions. We illustrate the range of SolarDS output using six PV penetration scenarios. In the first four scenarios, we simulate PV adoption for combinations of high and low PV cost reductions and two maximum market share curves. In the last two scenarios, we illustrate the upper bound on PV penetration using high PV cost reductions in addition to aggressive financing and policy-based parameters. These parameters are defined by (1) decreasing the loan rate from 6% (real) to 4% (real), (2) increasing the loan term from 15 to 30 years for residential retrofit and commercial systems, (3) changing the residential loan structure so that 30% of customers pay no down payment on PV loans and 70% of customers pay a 20% down payment, (4) increasing the electricity rate escalations from AEO 2009 estimates to a 1% annual increase, and (5) adding a cost to future carbon emissions. The input parameters for the six model scenarios are summarized in Table 1.

Table 1. SolarDS Input Parameters

		Scenario (PV Cost / Market-Penetration Curve / Finance & Policy)					
		EIA/ NEMS/ Base	**EIA/ Navigant/ Base**	**DOE SETP/ NEMS/ Base**	**DOE SETP/ Navigant/ Base**	**DOE SETP/ NEMS/ Aggressive**	**DOE SETP/ Navigant/ Aggressive**
PV Cost		EIA	EIA	DOE-SETP	DOE-SETP	DOE-SETP	DOE-SETP
Max PV Market Share		NEMS	Navigant	NEMS	Navigant	NEMS	Navigant
Rate Escalation		AEO 2009	AEO 2009	AEO 2009	AEO 2009	1% Annual	1% Annual
Rate Structures		Base Mix	Base Mix	Base Mix	Base Mix	Base Mix	Base Mix
Carbon Price[a]		-	-	-	-	\$20/ton CO_2 2010 - 2020 \$30/ton CO_2 2021 - 2030	\$20/ton CO_2 2010 - 2020 \$30/ton CO_2 2021-2030
Federal ITC		30% to 2016 com: 10% after	30% to 2016 com: 10% after	30% to 2016 com: 10% after	30% to 2016 com: 10% after	30% to 2016 res: 10% after com: 10% after	30% to 2016 res: 10% after com: 10% after
State Incentives		Current Incentives	Current Incentives	Current Incentives	Current Incentives	Current Incentives	Current Incentives
Loan Rate		6% (real)	6% (real)	6% (real)	6% (real)	5% (real)	5% (real)
Loan Term (years)		Com: 15[b] Res_{new}: 30 $Res_{existing}$: 15	Com: 15 Res_{new}: 30 $Res_{existing}$: 15	Com: 15 Res_{new}: 30 $Res_{existing}$: 15	Com: 15 Res_{new}: 30 $Res_{existing}$: 15	Com: 30 Res_{new}: 30 $Res_{existing}$: 30	Com: 30 Res_{new}: 30 $Res_{existing}$: 30
Down Payment (%)	**Com**	20%	20%	20%	20%	20%	20%
	20% of Res Homes	100%	100%	100%	100%	0%	0%
	80% of Res Homes	20%	20%	20%	20%	20%	20%

[a] U.S. \$2008 dollars
[b] Bolinger (2009)

Simulated PV penetration is shown in Figures 17 through 19. It ranges from 15 to 193 GW of PV capacity installed by 2030. The amount of installed PV capacity is highly dependent on future PV cost reductions. Modeled cumulative installed PV capacity reaches approximately 12 GW if future cost reductions follow EIA estimates (PV reaches \$4.23/W and \$2.85/W by 2030 for residential and commercial systems). Simulated PV capacity is approximately five times higher if PV cost reductions follow the DOE SETP targets (PV reaches \$2.09/W and \$1.66/W for residential and commercial systems by 2030). PV penetration is also highly sensitive to financing parameters, where a combination of the attractive financing parameters and a cost associated with carbon emissions (summarized in Table 1) leads to 158-193 GW of PV capacity by 2030.

The different PV maximum adoption fractions based on PV financial performance (NEMS and Navigant, see Figure 14) lead to small differences in the lower penetration scenarios, but significant differences (> 25 GW) in the high penetration scenario. This reflects similar adoption estimates for PV systems with higher payback times but a fundamental difference in estimated PV adoption for systems with very short payback periods. Additionally, the Navigant maximum market share curves lead to a significantly higher fraction of commercial to residential PV installations.

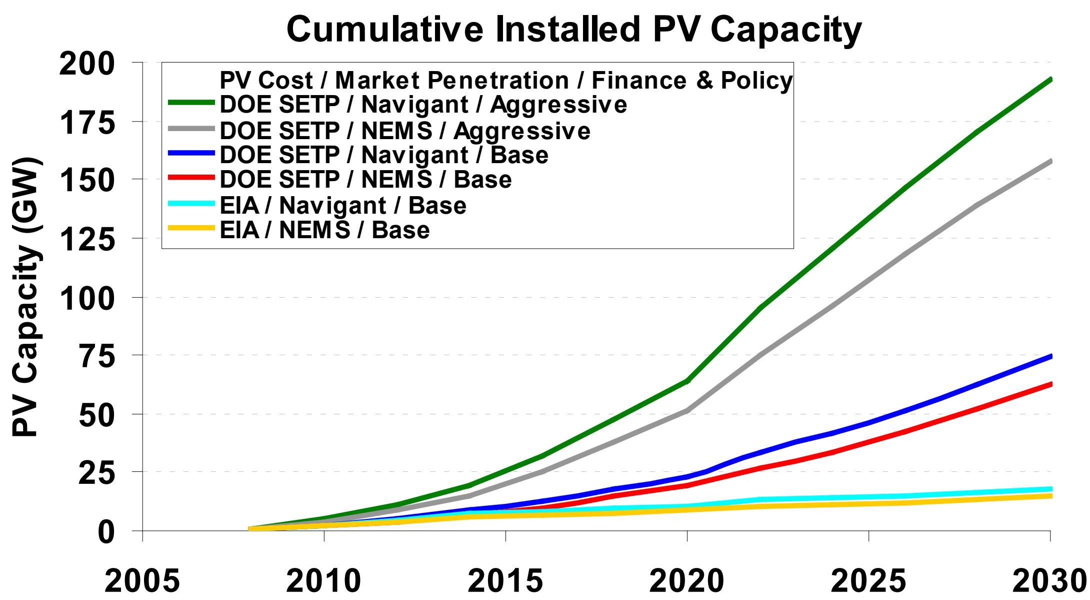


Figure 17. Cumulative installed PV capacity through 2030 for a range of model input parameters, including PV costs (EIA and DOE SETP), PV market adoption rates (NEMS and Navigant), and PV financing and policy assumptions (base case and aggressive case)

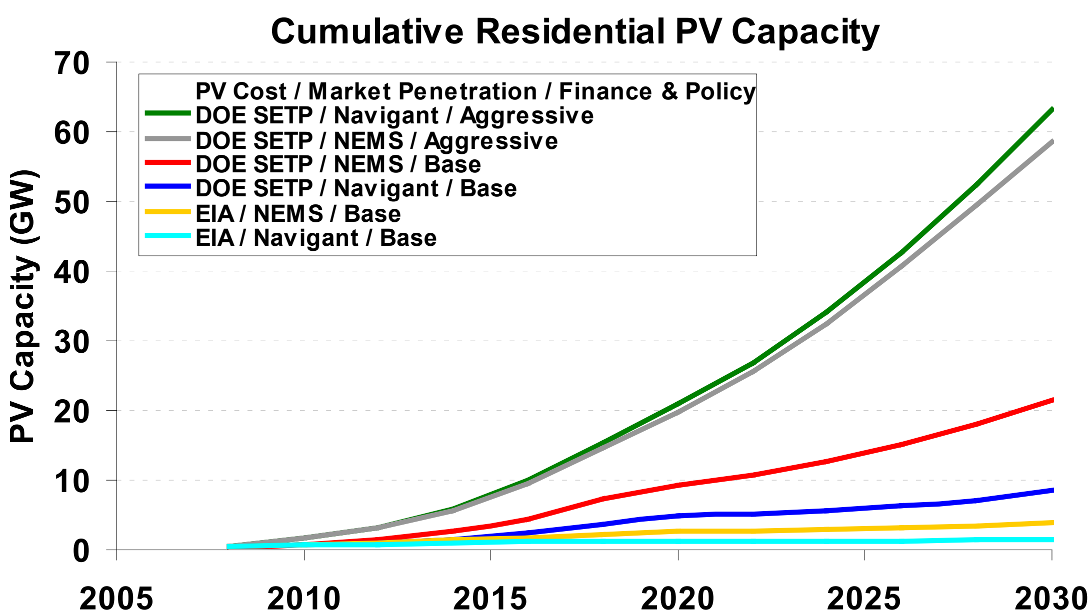


Figure 18. Cumulative installed residential PV capacity

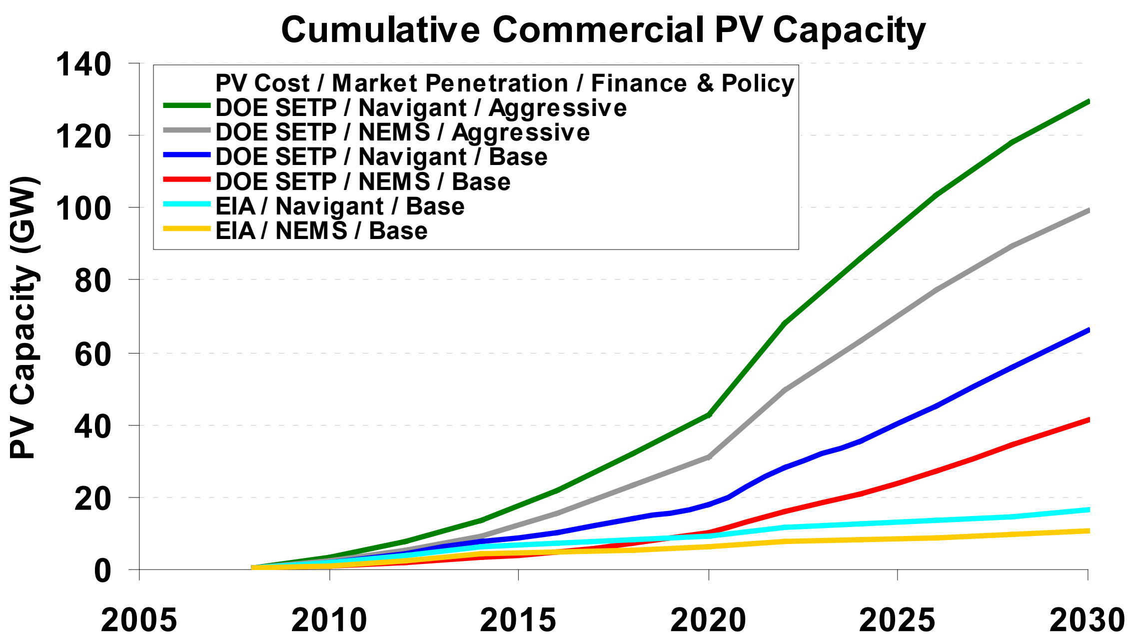


Figure 19. Cumulative installed commercial PV capacity

Table 2. Reference Case SolarDS Cumulative Installed PV Capacity

Scenario	PV Cost	Market Share		2008	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Reference Case[a]	EIA	NEMS	Total	0.8	1.9	3.5	5.7	6.5	7.8	8.7	10.5	11.2	12.1	13.3	14.9
			Residential	0.4	0.7	1.0	1.4	1.8	2.3	2.6	2.7	2.9	3.1	3.5	3.9
			Commercial	0.4	1.2	2.5	4.3	4.8	5.5	6.1	7.8	8.3	9.0	9.8	10.9
	EIA	Navigant	Total	0.8	2.3	4.7	7.5	8.4	9.4	10.3	13.1	14.0	14.8	16.0	17.7
			Residential	0.4	0.6	0.8	1.1	1.1	1.2	1.3	1.3	1.3	1.3	1.4	1.4
			Commercial	0.4	1.7	3.9	6.4	7.2	8.2	9.0	11.8	12.7	13.5	14.6	16.3
	DOE SETP	NEMS	Total	0.8	1.9	3.6	6.4	9.5	14.8	19.3	26.7	33.6	42.3	52.4	62.7
			Residential	0.4	0.9	1.5	2.7	4.5	7.4	9.2	10.7	12.6	15.1	18.0	21.5
			Commercial	0.4	1.0	2.1	3.6	5.0	7.5	10.0	16.0	21.0	27.3	34.3	41.2
	DOE SETP	Navigant	Total	0.8	2.4	5.2	9.2	12.5	17.7	22.9	33.3	41.3	51.2	62.8	74.7
			Residential	0.4	0.6	1.0	1.6	2.4	3.7	5.0	5.2	5.6	6.2	7.1	8.4
			Commercial	0.4	1.8	4.3	7.6	10.1	14.0	17.9	28.1	35.7	45.0	55.7	66.3
Attractive Case[b]	DOE SETP	NEMS	Total	0.8	3.9	8.7	15.1	24.9	37.9	50.9	75.2	95.8	118.0	139.0	157.7
			Residential	0.4	1.7	3.1	5.7	9.5	14.7	19.8	25.5	32.6	40.7	49.5	58.5
			Commercial	0.4	2.2	5.6	9.4	15.4	23.3	31.2	49.7	63.3	77.2	89.5	99.2
	DOE SETP	Navigant	Total	0.8	5.0	11.2	19.6	32.0	47.5	63.7	95.0	120.3	146.3	170.6	192.5
			Residential	0.4	1.8	3.2	5.9	9.9	15.3	21.0	26.8	34.2	42.8	52.4	63.1
			Commercial	0.4	3.2	8.0	13.7	22.1	32.2	42.8	68.2	86.1	103.5	118.2	129.5

[a] Reference case PV financing simulation, EIA electricity rate escalations, no carbon tax.
[b] Attractive financing simulation, 1% annual electricity rate escalations and a $20-30/TonC cost for carbon emissions.

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Appendix A: Model Regions and Electricity Rates

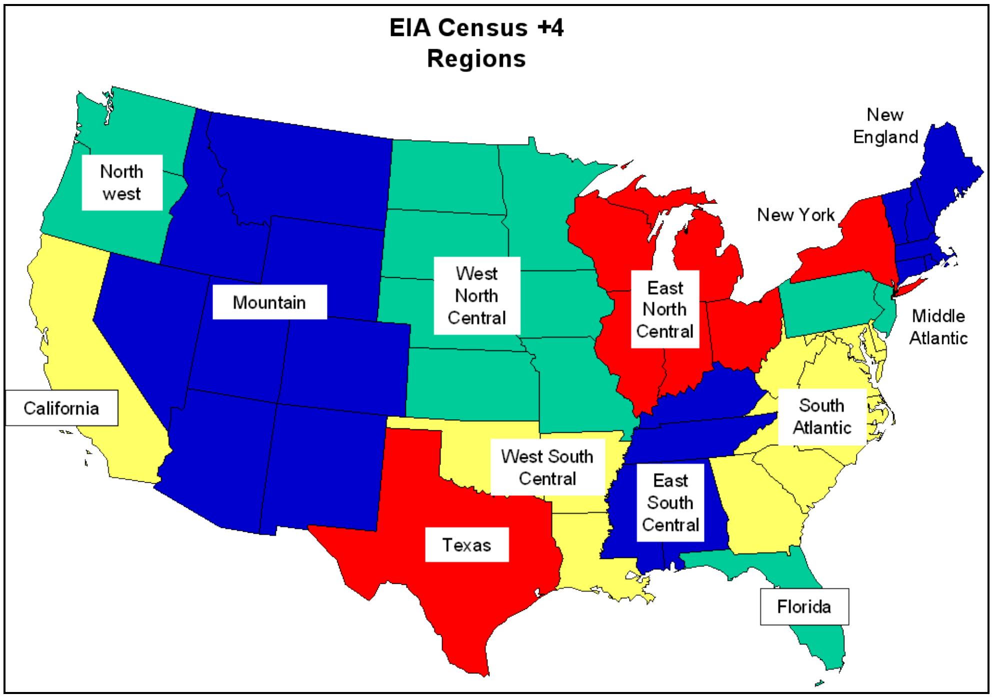

Figure A-1. EIA Census + 4 Regions

Table A-1. SolarDS Electricity Price Regions

SolarDS Price Region	Representative Utility	Residential Electricity Prices Mean	Residential Electricity Prices Min	Residential Electricity Prices Max	Commercial Electricity Prices Mean	Commercial Electricity Prices Min	Commercial Electricity Prices Max
Alabama	Alabama Power Co	9.32	6.40	13.70	8.70	5.58	13.87
Arizona	Arizona Public Service Co	9.66	5.31	13.19	8.27	2.05	12.06
Arkansas	Entergy Arkansas Inc	8.73	5.43	12.59	6.91	4.10	10.73
California (North)	Pacific Gas & Electric Co	14.41	8.40	23.42	13.23	6.11	14.21
California (South)	Southern California Edison	14.41	5.88	24.21	11.86	2.55	21.44
Colorado	Colorado Springs	9.25	6.06	13.80	7.62	2.24	18.55
Connecticut	United Illuminating Co	19.08	11.68	20.62	13.60	10.81	17.42
Delaware	Delmarva Power & Light Co.	13.15	10.78	15.70	10.59	8.55	15.29
District of Columbia	Potomac Electric Power Co	11.15	11.16	14.26	9.72	10.98	14.01
Florida	Florida Power Corp (Progress Energy)	11.22	7.63	14.32	9.75	6.79	14.41
Georgia	Georgia Power Co	9.10	5.47	13.63	8.07	5.79	12.50
Idaho	Idaho Power Co	6.36	4.91	9.81	5.14	4.09	8.19
Illinois	Commonwealth Edison Co	10.12	4.51	13.35	7.57	4.92	11.00
Indiana	PSI Energy Inc (Cinergy)	8.26	4.80	10.98	7.29	4.21	20.71
Iowa	Interstate Power (Alliant)	9.45	4.95	14.31	7.15	3.10	14.73
Kansas	Kansas City Power & Light	8.19	4.85	14.42	6.84	2.74	34.12
Kentucky	Kentucky Utilities Co	7.34	5.47	9.48	6.76	5.29	11.11
Louisiana	Entergy Louisiana Inc	9.37	3.10	12.36	9.13	2.94	33.33
Maine	Central Maine	9.62	9.37	34.64	8.27	9.23	23.82
Maryland	Baltimore Gas & Electric Co	11.83	7.37	14.42	10.23	7.06	18.11
Massachusetts	Boston Edison (Nstar)	15.53	9.21	18.65	12.56	10.06	19.87
Michigan	Detroit Edison Co	10.21	6.21	18.31	8.69	6.38	17.01
Minnesota	Northern States Power Co	9.18	5.36	14.58	7.48	1.88	13.59
Mississippi	Entergy Mississippi Inc	9.36	7.22	12.01	8.92	6.94	12.70

Missouri	Union Electric Co (Ameren)	7.69	4.67	13.48	6.34	3.96	13.52
Montana	NorthWestern Energy LLC	8.77	4.67	11.16	8.18	1.57	10.58
Nebraska	Omaha Public Power District	7.59	4.90	12.87	6.39	1.85	15.12
Nevada (North)	Sierra Pacific Power Co	8.40	5.64	13.04	6.09	4.15	12.56
Nevada (South)	Nevada Power Company	11.92	5.50	13.26	10.76	0.87	14.06
New Hampshire	Public Service Co of NH	14.88	10.18	31.70	12.65	10.20	16.37
New Jersey	Jersey Central Power & Lt Co	14.14	9.11	15.30	11.75	9.18	15.98
New Mexico	Public Service Co of NM	9.12	7.59	16.65	7.66	3.86	41.97
New York (Long Island)	Long Island Power Authority	20.25	18.49	22.67	16.11	16.81	20.99
New York (NYC)	Consolidated Edison-NYC	19.08	19.08	30.62	17.50	17.18	19.75
New York (Remain)	Niagara Mohawk Power Corp	13.30	2.64	19.36	10.40	3.37	18.42
North Carolina	Carolina Power & Light (Progress)	9.40	6.70	13.86	7.43	5.94	16.67
North Dakota	Northern States Power Co	7.30	4.93	9.73	6.58	1.90	9.32
Ohio	Ohio Power Co (AEP)	9.35	5.56	12.85	8.22	4.71	13.24
Oklahoma	Oklahoma Gas & Electric Co	8.58	5.37	16.40	7.33	4.48	28.99
Oregon	Portland General Electric Company	8.19	4.22	10.70	7.11	3.40	10.96
Pennsylvania	PECO Energy Co	10.86	6.99	20.45	8.98	5.09	17.94
Rhode island	Narragansett Electric Co	14.04	13.85	40.12	11.89	12.15	42.02
South Carolina	South Carolina Electric & Gas	9.19	7.50	15.63	7.74	4.61	11.32
South Dakota	Black Hills Power Inc	8.07	4.85	11.49	6.61	1.98	17.16
Tennessee	Memphis City of	7.84	1.37	11.51	8.09	5.61	12.97
Texas	TXU Energy Retail Co LP	12.34	7.32	18.16	9.87	4.10	16.24
Utah	PacifiCorp	8.15	2.64	11.90	6.54	2.08	13.25
Vermont	Central Vermont Pub Service	14.15	8.16	16.91	12.29	9.63	18.51
Virginia	Virginia Electric & Power (Dominion)	8.74	6.26	12.99	6.38	5.51	13.14
Washington	Puget Sound Energy Inc	7.26	2.27	9.92	6.56	2.28	10.00
West Virginia	Appalachian Power Co	6.73	6.15	13.15	5.85	5.58	13.20
Wisconsin	Wisconsin Electric Power Co	10.87	6.17	15.45	8.71	5.65	13.87
Wyoming	PacifiCorp	7.75	2.94	13.06	6.25	1.68	13.12

Because load patterns may vary for different climate patterns in northern and southern California, the state is separated into two regions to allow for different TOU rates. Nevada is split into two regions to allow for escalation based on the NEMS EMM regions. New York is separated into three regions. Generation and transmission into New York City and Long Island is severely constrained, resulting in much higher than average prices.

Table A-2. AEO 2009[19] Rate Escalation by Region: Residential

Region[a]	2008	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	%
NE	1.00	0.93	0.97	0.97	0.97	0.98	0.99	0.98	0.99	1.01	1.02	1.03	0.1
MA	1.00	0.89	0.93	0.97	0.98	0.99	1.00	1.00	1.03	1.06	1.08	1.09	0.7
ENC	1.00	0.95	0.97	0.99	1.00	1.01	1.02	1.04	1.05	1.08	1.10	1.12	0.5
WNC	1.00	1.01	1.02	1.03	1.02	1.02	1.02	1.02	1.02	1.03	1.04	1.06	0.3
SA	1.00	0.96	0.99	1.00	1.01	1.02	1.03	1.04	1.06	1.10	1.13	1.14	0.8
ESC	1.00	0.98	0.98	0.98	0.98	0.99	0.99	1.00	1.02	1.05	1.08	1.10	0.8
WSC	1.00	0.93	0.95	0.97	0.98	1.00	1.03	1.04	1.06	1.10	1.13	1.14	0.7
MTN	1.00	1.02	1.02	1.03	1.05	1.09	1.11	1.12	1.17	1.22	1.26	1.30	1.4
PAC	1.00	0.96	0.94	0.93	0.93	0.94	0.94	0.94	0.95	0.98	1.00	1.01	0.1

[a] Regions are shown in Figure A-1.

[19] Real, not nominal, electricity rate escalations (EIA 2009).

Table A-3. AEO 2009 Rate Escalation by Region: Commercial

Region[a]	2008	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	%
NE	1.00	0.89	0.89	0.87	0.87	0.89	0.91	0.90	0.92	0.94	0.97	0.99	-0.1
MA	1.00	0.85	0.86	0.89	0.92	0.94	0.95	0.96	0.99	1.03	1.06	1.08	0.6
ENC	1.00	0.92	0.91	0.91	0.93	0.95	0.97	0.99	1.00	1.04	1.07	1.10	0.7
WNC	1.00	0.99	0.99	1.00	0.99	1.00	1.00	0.99	1.00	1.01	1.03	1.06	0.8
SA	1.00	0.92	0.94	0.94	0.94	0.95	0.96	0.96	0.98	1.02	1.05	1.06	0.7
ESC	1.00	0.95	0.94	0.92	0.92	0.93	0.93	0.94	0.96	0.99	1.02	1.04	0.3
WSC	1.00	0.90	0.90	0.92	0.92	0.96	0.99	1.00	1.03	1.08	1.12	1.14	0.5
MTN	1.00	0.97	0.94	0.93	0.94	0.97	0.98	0.98	1.02	1.06	1.10	1.13	0.9
PAC	1.00	0.97	0.92	0.89	0.89	0.90	0.90	0.89	0.90	0.93	0.95	0.97	-0.1

[a] Regions are shown in Figure A-1.

Table A-4. SolarDS Regions and Population Allocation

SolarDS Site Number	SolarDS Electricity Rate Region	TMY Site (State & City)	Allocated Population (yr 2000)	Fraction of State Population
1	AL	AL Birmingham	1,572,515	35.36%
2	AL	AL Huntsville	907,369	20.40%
3	AL	AL Montgomery	759,750	17.08%
4	AL	AL Mobile	620,977	13.96%
5	AL	GA Columbus	302,428	6.80%
6	AL	MS Meridian	102,777	2.31%
7	AL	TN Chattanooga	97,596	2.19%
8	AL	FL Tallahassee	69,559	1.56%
9	AL	GA Atlanta	14,129	0.32%
10	AR	AR Little Rock	1,329,509	49.73%
11	AR	AR Fort Smith	628,182	23.50%
12	AR	TN Memphis	395,581	14.80%
13	AR	LA Shreveport	170,909	6.39%
14	AR	MO Springfield	139,097	5.20%
15	AR	MS Jackson	10,122	0.38%
16	AZ	AZ Phoenix	3,275,528	63.84%
17	AZ	AZ Tucson	1,094,445	21.33%
18	AZ	AZ Flagstaff	296,989	5.79%
19	AZ	AZ Prescott	179,906	3.51%
20	AZ	NV Las Vegas	140,581	2.74%
21	AZ	CA San Diego	122,405	2.39%
22	AZ	UT Cedar City	9,379	0.18%
23	AZ	NM Albuquerque	7,672	0.15%
24	AZ	CO Grand Junction	3,727	0.07%
25	CA So	CA Long Beach	8,706,405	25.70%
26	CA No	CA San Francisco	7,101,835	20.97%
27	CA So	CA Los Angeles	6,245,807	18.44%
28	CA No	CA Sacramento	3,859,322	11.39%
29	CA So	CA San Diego	3,285,362	9.70%
30	CA So	CA Fresno	1,568,991	4.63%
31	CA So	CA Daggett	1,103,365	3.26%
32	CA So	CA Bakersfield	750,676	2.22%
33	CA So	CA Santa Maria	658,686	1.94%
34	CA No	CA Arcata	348,186	1.03%
35	CA No	NV Reno	136,149	0.40%
36	CA No	OR Medford	74,816	0.22%
37	CA So	AZ Prescott	14,411	0.04%
38	CA So	NV Tonopah	7,501	0.02%

39	CA So	NV Las Vegas	7,002	0.02%
40	CA No	OR Burns	1,594	0.00%
41	CA So	AZ Phoenix	1,540	0.00%
42	CO	CO Boulder	2,773,036	64.47%
43	CO	CO Colorado Springs	667,357	15.52%
44	CO	CO Grand Junction	251,827	5.85%
45	CO	CO Pueblo	205,112	4.77%
46	CO	CO Eagle	178,849	4.16%
47	CO	CO Alamosa	87,957	2.04%
48	CO	WY Cheyenne	65,940	1.53%
49	CO	KS Goodland	46,235	1.07%
50	CO	NE Scottsbluff	23,387	0.54%
51	CT	CT Bridgeport	1,681,647	49.38%
52	CT	CT Hartford	1,415,748	41.57%
53	CT	RI Providence	204,546	6.01%
54	CT	MA Worchester	54,689	1.61%
55	CT	NY New York City	48,935	1.44%
56	DC	VA Sterling	308,382	53.91%
57	DC	MD Baltimore	263,677	46.09%
58	DE	DE Wilmington	715,639	91.33%
59	DE	NJ Atlantic City	65,930	8.41%
60	DE	PA Philadelphia	2,031	0.26%
61	FL	FL Tampa	4,380,438	27.41%
62	FL	FL Miami	3,871,126	24.22%
63	FL	FL Daytona Beach	2,863,036	17.91%
64	FL	FL West Palm Beach	2,004,991	12.55%
65	FL	FL Jacksonville	1,493,393	9.34%
66	FL	FL Tallahassee	677,509	4.24%
67	FL	AL Mobile	526,559	3.29%
68	FL	AL Montgomery	89,085	0.56%
69	FL	FL Key West	76,241	0.48%
70	GA	GA Atlanta	4,094,795	50.02%
71	GA	GA Macon	824,151	10.07%
72	GA	GA Athens	754,462	9.22%
73	GA	GA Savannah	545,545	6.66%
74	GA	TN Chattanooga	455,212	5.56%
75	GA	GA Columbus	435,625	5.32%
76	GA	GA Augusta	430,861	5.26%
77	GA	FL Tallahassee	386,233	4.72%
78	GA	FL Jacksonville	223,874	2.73%
79	GA	TN Knoxville	30,782	0.38%
80	GA	NC Asheville	4,913	0.06%
81	KS	IA Des Moines	879,236	30.05%
82	KS	IL Moline	654,336	22.36%
83	KS	IA Waterloo	603,638	20.63%
84	KS	IA Sioux City	252,352	8.62%
85	KS	IA Mason City	226,679	7.75%
86	KS	NE Omaha	213,387	7.29%
87	KS	WI La Crosse	43,869	1.50%
88	KS	SD Sioux Falls	37,013	1.26%
89	KS	MN Rochester	14,291	0.49%
90	KS	MO Kansas City	1,523	0.05%
91	ID	ID Boise	584,342	45.16%
92	ID	ID Pocatello	425,334	32.87%
93	ID	WA Spokane	267,814	20.70%

94	ID	MT Missoula	14,240	1.10%
95	ID	NV Elko	1,297	0.10%
96	IL	IL Chicago	7,930,677	63.86%
97	IL	IL Springfield	886,011	7.13%
98	IL	MO St. Louis	872,763	7.03%
99	IL	IL Rockford	793,140	6.39%
100	IL	IL Peoria	696,099	5.60%
101	IL	IN Evansville	384,252	3.09%
102	IL	IL Moline	380,800	3.07%
103	IL	WI Milwaukee	325,274	2.62%
104	IL	IN Indianapolis	92,878	0.75%
105	IL	MO Columbia	55,277	0.45%
106	IL	WI Madison	2,122	0.02%
107	IN	IN Indianapolis	2,563,710	42.16%
108	IN	IN Fort Wayne	939,718	15.45%
109	IN	IN South Bend	811,154	13.34%
110	IN	IL Chicago	639,617	10.52%
111	IN	IN Evansville	484,918	7.97%
112	IN	KY Louisville	383,808	6.31%
113	IN	KY Covington	176,230	2.90%
114	IN	OH Dayton	81,330	1.34%
115	KS	KS Wichita	854,287	31.78%
116	KS	MO Kansas City	742,639	27.62%
117	KS	KS Topeka	602,412	22.41%
118	KS	KS Dodge City	247,028	9.19%
119	KS	OK Tulsa	85,965	3.20%
120	KS	MO Springfield	60,854	2.26%
121	KS	NE Grand Island	44,366	1.65%
122	KS	KS Goodland	42,533	1.58%
123	KS	NE North Platte	5,953	0.22%
124	KS	TX Amarillo	2,381	0.09%
125	KY	KY Louisville	1,179,255	29.18%
126	KY	KY Lexington	1,024,225	25.34%
127	KY	IN Evansville	521,506	12.90%
128	KY	KY Covington	401,353	9.93%
129	KY	WV Huntington	343,734	8.50%
130	KY	TN Nashville	295,411	7.31%
131	KY	TN Bristol	138,437	3.43%
132	KY	TN Knoxville	123,850	3.06%
133	KY	TN Memphis	13,046	0.32%
134	LA	LA New Orleans	1,650,111	36.92%
135	LA	LA Baton Rouge	1,342,161	30.03%
136	LA	LA Shreveport	789,351	17.66%
137	LA	LA Lake Charles	581,675	13.02%
138	LA	MS Jackson	101,030	2.26%
139	LA	TX Port Arthur	2,323	0.05%
140	LA	TX Lufkin	1,241	0.03%
141	LA	AR Little Rock	1,084	0.02%
142	MA	MA Boston	3,942,239	62.09%
143	MA	MA Worchester	942,773	14.85%
144	MA	RI Providence	681,104	10.73%
145	MA	CT Hartford	667,208	10.51%
146	MA	NY Albany	112,944	1.78%
147	MA	NH Concord	2,829	0.04%
148	MD	MD Baltimore	3,812,860	71.99%
149	MD	VA Sterling	1,074,159	20.28%
150	MD	DE Wilmington	225,657	4.26%

151	MD	WV Elkins	101,035	1.91%
152	MD	NJ Atlantic City	33,529	0.63%
153	MD	VA Norfolk	24,184	0.46%
154	MD	PA Harrisburg	22,844	0.43%
155	MD	VA Richmond	2,218	0.04%
156	ME	ME Portland	1,106,971	86.83%
157	ME	ME Caribou	161,071	12.63%
158	ME	NH Concord	6,879	0.54%
159	MI	MI Detroit	4,119,864	41.45%
160	MI	MI Flint	1,521,185	15.31%
161	MI	MI Grand Rapids	1,268,740	12.77%
162	MI	MI Lansing	916,640	9.22%
163	MI	MI Muskegon	466,710	4.70%
164	MI	OH Toledo	403,237	4.06%
165	MI	MI Traverse City	402,807	4.05%
166	MI	IN South Bend	312,555	3.14%
167	MI	MI Alpena	161,440	1.62%
168	MI	MI Houghton	159,262	1.60%
169	MI	MI Sault Ste. Marie	83,312	0.84%
170	MI	WI Green Bay	82,885	0.83%
171	MI	IN Fort Wayne	39,807	0.40%
172	MN	MN Minneapolis	2,925,313	59.46%
173	MN	MN Saint Cloud	750,930	15.26%
174	MN	MN Rochester	290,122	5.90%
175	MN	ND Fargo	277,098	5.63%
176	MN	MN Duluth	275,310	5.60%
177	MN	SD Sioux Falls	128,968	2.62%
178	MN	MN Int. Falls	102,273	2.08%
179	MN	IA Mason City	100,571	2.04%
180	MN	WI La Crosse	66,761	1.36%
181	MN	MI Houghton	2,133	0.04%
182	MO	MO St. Louis	2,305,473	41.20%
183	MO	MO Kansas City	1,339,611	23.94%
184	MO	MO Springfield	928,348	16.59%
185	MO	MO Columbia	789,478	14.11%
186	MO	TN Memphis	183,023	3.27%
187	MO	IA Des Moines	25,526	0.46%
188	MO	NE Omaha	7,522	0.13%
189	MO	IL Moline	6,541	0.12%
190	MO	AR Fort Smith	5,576	0.10%
191	MO	AR Little Rock	3,290	0.06%
192	MS	MS Jackson	987,829	34.73%
193	MS	TN Memphis	640,766	22.53%
194	MS	MS Meridian	566,672	19.92%
195	MS	AL Mobile	392,699	13.80%
196	MS	LA Baton Rouge	107,514	3.78%
197	MS	LA New Orleans	106,861	3.76%
198	MS	AL Huntsville	35,500	1.25%
199	MS	AL Birmingham	4,255	0.15%
200	MS	AR Little Rock	2,562	0.09%
201	MT	MT Helena	215,795	23.92%
202	MT	MT Billings	160,099	17.75%
203	MT	MT Missoula	156,726	17.37%
204	MT	MT Kalispell	114,474	12.69%
205	MT	MT Great Falls	92,603	10.26%

206	MT	MT Lewistown	48,210	5.34%
207	MT	MT Miles City	46,451	5.15%
208	MT	MT Glasgow	30,864	3.42%
209	MT	MT Cut Bank	26,874	2.98%
210	MT	WY Sheridan	9,725	1.08%
211	NC	NC Raleigh	2,415,001	30.00%
212	NC	NC Charlotte	1,937,866	24.07%
213	NC	NC Greensboro	1,565,781	19.45%
214	NC	NC Wilmington	968,937	12.04%
215	NC	NC Asheville	553,844	6.88%
216	NC	VA Norfolk	186,361	2.32%
217	NC	TN Bristol	117,225	1.46%
218	NC	NC Cape Hatteras	99,890	1.24%
219	NC	SC Greenville	77,647	0.96%
220	NC	TN Knoxville	72,009	0.89%
221	NC	VA Richmond	54,752	0.68%
222	ND	ND Fargo	299,370	46.62%
223	ND	ND Bismarck	169,768	26.44%
224	ND	ND Minot	161,314	25.12%
225	ND	SD Rapid City	5,255	0.82%
226	ND	SD Huron	3,288	0.51%
227	ND	MT Miles City	3,205	0.50%
228	NE	NE Omaha	1,003,230	58.63%
229	NE	NE Grand Island	255,129	14.91%
230	NE	NE Norfolk	170,039	9.94%
231	NE	NE North Platte	123,185	7.20%
232	NE	NE Scottsbluff	87,861	5.13%
233	NE	IA Sioux City	44,784	2.62%
234	NE	KS Topeka	14,250	0.83%
235	NE	SD Pierre	4,749	0.28%
236	NE	KS Goodland	3,696	0.22%
237	NE	SD Rapid City	3,378	0.20%
238	NH	NH Concord	1,036,495	83.87%
239	NH	MA Boston	90,888	7.35%
240	NH	MA Worchester	67,484	5.46%
241	NH	ME Portland	40,919	3.31%
242	NJ	NJ Newark	4,737,665	56.30%
243	NJ	PA Philadelphia	1,393,310	16.56%
244	NJ	NY New York City	1,183,079	14.06%
245	NJ	NJ Atlantic City	802,935	9.54%
246	NJ	PA Allentown	218,664	2.60%
247	NJ	DE Wilmington	78,697	0.94%
248	NM	NM Albuquerque	1,160,120	63.78%
249	NM	TX El Paso	330,045	18.14%
250	NM	NM Tucumcari	150,391	8.27%
251	NM	TX Midland	88,442	4.86%
252	NM	CO Alamosa	53,246	2.93%
253	NM	CO Grand Junction	22,789	1.25%
254	NM	CO Pueblo	7,509	0.41%
255	NM	AZ Tucson	4,324	0.24%
256	NM	TX Lubbock	2,180	0.12%
257	NV South	NV Las Vegas	1,402,358	70.18%
258	NV North	NV Reno	498,607	24.95%
259	NV North	NV Elko	46,363	2.32%
260	NV North	NV Winnemucca	29,454	1.47%
261	NV North	NV Ely	10,799	0.54%

262	NV North	NV Tonopah	8,231	0.41%
263	NV North	UT Cedar City	2,445	0.12%
264	NYC	NY New York City	10,444,179	55.04%
265	NY Long Is.	CT Bridgeport	1,609,017	8.48%
266	NY Remain	NY Albany	1,363,859	7.19%
267	NY Remain	NY Buffalo	1,301,957	6.86%
268	NY Remain	NY Syracuse	1,194,945	6.30%
269	NY Remain	NY Rochester	1,167,876	6.15%
270	NY Remain	NJ Newark	683,302	3.60%
271	NY Remain	NY Binghamton	600,670	3.17%
272	NY Remain	NY Massena	177,545	0.94%
273	NY Remain	PA Bradford	162,687	0.86%
274	NY Remain	VT Burlington	123,234	0.65%
275	NY Remain	PA Williamsport	65,309	0.34%
276	NY Remain	PA Wilkes-Barre	43,752	0.23%
277	NY Remain	PA Erie	30,434	0.16%
278	NY Long Is.	RI Providence	7,253	0.04%
279	OH	OH Cleveland	2,081,112	18.33%
280	OH	OH Columbus	1,971,782	17.37%
281	OH	OH Dayton	1,575,838	13.88%
282	OH	OH Akron	1,430,359	12.60%
283	OH	KY Covington	1,401,769	12.35%
284	OH	OH Toledo	950,637	8.37%
285	OH	OH Youngstown	706,904	6.23%
286	OH	OH Mansfield	584,256	5.15%
287	OH	WV Huntington	264,509	2.33%
288	OH	PA Pittsburgh	187,418	1.65%
289	OH	WV Charleston	89,023	0.78%
290	OH	IN Fort Wayne	86,071	0.76%
291	OH	PA Erie	22,699	0.20%
292	OK	OK Oklahoma City	1,532,614	44.42%
293	OK	OK Tulsa	1,205,649	34.94%
294	OK	TX Wichita Falls	258,003	7.48%
295	OK	AR Fort Smith	245,796	7.12%
296	OK	TX Fort Worth	79,327	2.30%
297	OK	KS Wichita	64,081	1.86%
298	OK	KS Dodge City	39,340	1.14%
299	OK	TX Amarillo	22,345	0.65%
300	OK	MO Springfield	2,625	0.08%
301	OR	OR Portland	1,496,864	43.75%
302	OR	OR Salem	600,743	17.56%
303	OR	OR Eugene	416,059	12.16%
304	OR	OR Medford	339,927	9.94%
305	OR	OR Redmond	165,561	4.84%
306	OR	OR Pendleton	129,504	3.79%
307	OR	OR North Bend	124,757	3.65%
308	OR	OR Astoria	63,423	1.85%
309	OR	ID Boise	33,681	0.98%
310	OR	OR Burns	19,947	0.58%
311	OR	WA Yakima	19,267	0.56%
312	OR	CA Arcata	11,269	0.33%
313	PA	PA Philadelphia	3,234,722	26.34%
314	PA	PA Pittsburgh	2,725,698	22.19%
315	PA	PA Harrisburg	1,770,423	14.42%
316	PA	PA Allentown	1,447,170	11.78%
317	PA	PA Wilkes-Barre	763,011	6.21%

318	PA	PA Williamsport	566,515	4.61%
319	PA	PA Bradford	524,237	4.27%
320	PA	DE Wilmington	429,600	3.50%
321	PA	PA Erie	417,499	3.40%
322	PA	OH Youngstown	207,952	1.69%
323	PA	VA Sterling	87,401	0.71%
324	PA	NY Binghamton	67,329	0.55%
325	PA	WV Elkins	27,144	0.22%
326	PA	MD Baltimore	6,507	0.05%
327	PA	NJ Newark	5,846	0.05%
328	RI	RI Providence	1,043,056	99.50%
329	RI	MA Worchester	5,263	0.50%
330	SC	SC Greenville	1,146,765	28.58%
331	SC	SC Columbia	989,877	24.67%
332	SC	SC Charleston	895,614	22.32%
333	SC	NC Charlotte	340,746	8.49%
334	SC	GA Augusta	205,513	5.12%
335	SC	NC Wilmington	203,937	5.08%
336	SC	GA Savannah	161,436	4.02%
337	SC	GA Athens	40,482	1.01%
338	SC	NC Asheville	17,608	0.44%
339	SC	NC Raleigh	9,391	0.23%
340	SD	SD Sioux Falls	261,762	34.68%
341	SD	SD Rapid City	180,019	23.85%
342	SD	SD Huron	170,861	22.64%
343	SD	SD Pierre	74,640	9.89%
344	SD	NE Norfolk	23,383	3.10%
345	SD	IA Sioux City	21,031	2.79%
346	SD	ND Fargo	14,552	1.93%
347	SD	ND Bismarck	8,596	1.14%
348	TN	TN Nashville	1,838,670	32.32%
349	TN	TN Memphis	1,388,930	24.41%
350	TN	TN Knoxville	1,085,595	19.08%
351	TN	TN Chattanooga	691,610	12.16%
352	TN	TN Bristol	486,175	8.55%
353	TN	AL Huntsville	186,174	3.27%
354	TN	NC Asheville	12,129	0.21%
355	TX	TX Fort Worth	5,608,872	26.90%
356	TX	TX Houston	4,955,756	23.77%
357	TX	TX San Antonio	1,916,970	9.19%
358	TX	TX Austin	1,434,729	6.88%
359	TX	TX Brownsville	978,369	4.69%
360	TX	TX Corpus Christi	750,132	3.60%
361	TX	TX Waco	748,004	3.59%
362	TX	TX El Paso	690,669	3.31%
363	TX	TX Lufkin	637,769	3.06%
364	TX	LA Shreveport	494,013	2.37%
365	TX	TX Port Arthur	431,235	2.07%
366	TX	TX Midland	390,808	1.87%
367	TX	TX Lubbock	389,346	1.87%
368	TX	TX Amarillo	382,332	1.83%
369	TX	TX Abilene	309,567	1.48%
370	TX	TX Victoria	273,952	1.31%
371	TX	TX Wichita Falls	224,372	1.08%
372	TX	TX San Angelo	208,457	1.00%
373	TX	NM Tucumcari	12,779	0.06%
374	TX	LA Lake Charles	6,917	0.03%

375	TX	AR Fort Smith	3,715	0.02%
376	TX	KS Dodge City	3,057	0.01%
377	UT	UT Salt Lake City	1,999,247	89.53%
378	UT	UT Cedar City	167,106	7.48%
379	UT	WY Rock Springs	34,848	1.56%
380	UT	CO Grand Junction	27,207	1.22%
381	UT	ID Pocatello	2,774	0.12%
382	UT	NV Ely	1,503	0.07%
383	VA	VA Sterling	2,331,222	32.93%
384	VA	VA Norfolk	1,596,461	22.55%
385	VA	VA Richmond	1,298,552	18.34%
386	VA	VA Lynchburg	686,010	9.69%
387	VA	VA Roanoke	598,542	8.46%
388	VA	TN Bristol	308,708	4.36%
389	VA	NC Greensboro	114,750	1.62%
390	VA	WV Elkins	100,092	1.41%
391	VA	NC Raleigh	26,430	0.37%
392	VA	WV Charleston	14,425	0.20%
393	VA	TN Knoxville	3,323	0.05%
394	VT	VT Burlington	469,834	77.17%
395	VT	NH Concord	60,899	10.00%
396	VT	NY Albany	49,152	8.07%
397	VT	MA Worchester	16,013	2.63%
398	VT	CT Hartford	12,929	2.12%
399	WA	WA Seattle	3,616,970	61.37%
400	WA	WA Spokane	572,474	9.71%
401	WA	WA Yakima	476,574	8.09%
402	WA	OR Portland	440,819	7.48%
403	WA	WA Olympia	427,598	7.25%
404	WA	OR Pendleton	253,513	4.30%
405	WA	OR Astoria	63,216	1.07%
406	WA	WA Quillayute	42,957	0.73%
407	WI	WI Milwaukee	1,981,735	36.95%
408	WI	WI Green Bay	1,203,284	22.43%
409	WI	WI Madison	997,047	18.59%
410	WI	WI Eau Claire	446,623	8.33%
411	WI	WI La Crosse	297,580	5.55%
412	WI	IL Rockford	157,144	2.93%
413	WI	MN Minneapolis	117,746	2.20%
414	WI	MN Duluth	96,387	1.80%
415	WI	MI Houghton	46,879	0.87%
416	WI	IL Moline	11,857	0.22%
417	WI	MN Rochester	6,733	0.13%
418	WV	WV Charleston	778,188	43.03%
419	WV	WV Elkins	450,975	24.94%
420	WV	WV Huntington	190,247	10.52%
421	WV	PA Pittsburgh	166,590	9.21%
422	WV	VA Sterling	147,523	8.16%
423	WV	VA Roanoke	69,468	3.84%
424	WV	TN Bristol	5,353	0.30%
425	WY	WY Cheyenne	122,428	24.79%
426	WY	WY Casper	94,348	19.11%
427	WY	WY Sheridan	76,994	15.59%
428	WY	WY Lander	52,669	10.67%
429	WY	WY Rock Springs	49,670	10.06%
430	WY	MT Billings	29,315	5.94%
431	WY	ID Pocatello	25,100	5.08%

432	WY	NE Scottsbluff	14,945	3.03%
433	WY	UT Salt Lake City	14,695	2.98%
434	WY	SD Rapid City	12,531	2.54%
435	WY	CO Eagle	1,087	0.22%

Appendix B: PV Performance and Cost Reductions

Table B-1. PV Derate Factor by Component

Component	Derate Factor
PV module nameplate DC rating	0.95
Inverter and transformer	0.92
Mismatch	0.98
Diodes and connections	0.995
DC wiring	0.98
AC wiring	0.99
Soiling	0.95
System availability	0.98
Overall DC-to-AC derate Factor	0.77[a]

[a] This corresponds to the derate factor of a new module. We also assume that PV output degrades over time, resulting in a 10% reduction in 20 years.

Table B-2. PV Cost Reductions[a]

Year	Residential ($/kW)				Commercial ($/kW)			
	EIA		DOE - SPT		EIA		DOE - SPT	
	PV	Inverter[b]	PV	Inverter	PV	Inverter	PV	Inverter
2008	8000	729	8000	500	6800	527	6800	500
2010	6603	729	5159	310	5515	519	4128	200
2012	6438	729	4458	290	5024	519	3389	190
2014	6214	721	3756	280	4533	512	2650	180
2016	5704	717	3303	260	4192	512	2212	170
2018	5403	713	3099	240	4000	508	2075	160
2020	5101	709	2894	220	3808	504	1938	165
2022	4928	705	2721	210	3616	501	1861	150
2024	4754	705	2547	200	3424	497	1783	140
2026	4580	697	2386	190	3232	497	1727	130
2028	4406	693	2239	190	3040	493	1692	130
2030	4233	689	2091	190	2848	489	1657	130

[a] In nominal 2008 U.S. dollars
[b] Inverter replacement is scheduled every 10-20 years, with inverter lifetime increasing over time.

Learning-based Cost Reductions

The idea of learning-based cost reductions stems from the observation that workers in manufacturing plants become more efficient as they produce more units. This idea has been extended to describe the cost reductions and quality improvements in a wide variety of manufactured products. One reason for its widespread use is the availability of data on unit production and unit cost. The learning rate, LR, is derived from cost data, C_t, and cumulative manufactured data, q_t, using the following relationship:

$$C_{t+1} = C_t \left(\frac{q_{t+1}}{q_t} \right)^{\frac{\ln(1-LR_t)}{\ln(2)}} \tag{B-1}$$

The global cumulative installed PV amount/rate is inferred from the cumulative amount of PV installed in a given time period using the fraction of PV installed in the US, $f_{US,t}$, as follows:

$$q_t = \frac{q_{US,t}}{f_{US,t}} \tag{B-2}$$

Recent surveys of PV learning rates suggest values ranging from 17% to 26% (Maycock 2002; Strategies Unlimited 2003; Nemet 2006). The NEMS model uses a constant PV learning rate of approximately 13%. SolarDS allows users to specify both the learning rate and the fraction of U.S. to global cumulative installed PV capacity for each time period in SolarDS. Figure B-1 shows the PV cost reductions for fixed learning rates of 17% and 26%, assuming a fixed U.S. to global cumulative installed PV capacity fraction.

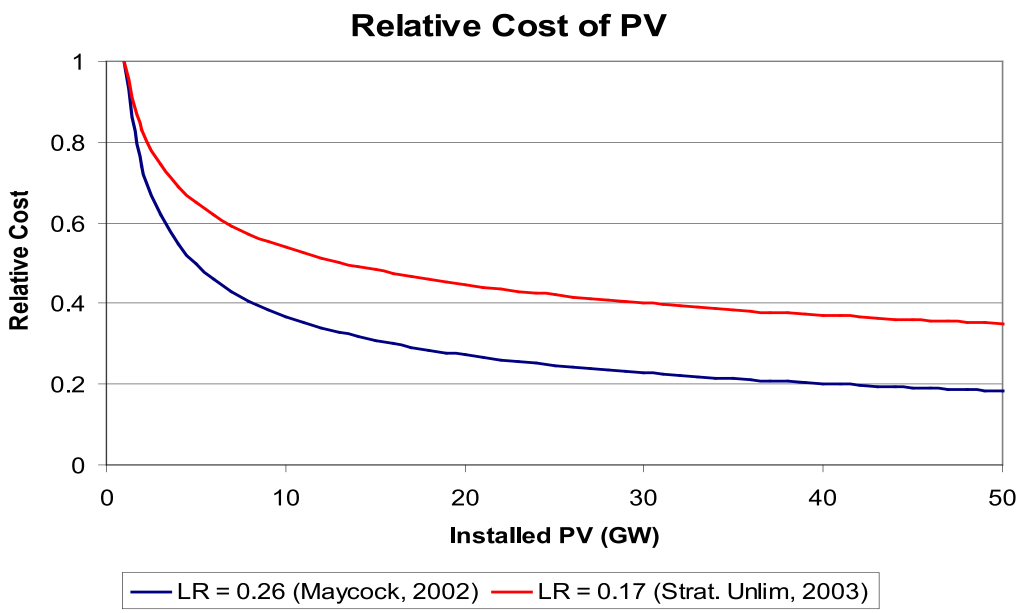

Figure B-1. PV Cost reductions for two PV learning rates (*LR*) derived in recent studies.

Although PV prices can be reasonably expected to decrease with cumulative production, users should keep certain factors in mind when using learning rates. Extrapolating learning rates from historical PV price and production data may not reflect the current and future reductions in PV costs. Additionally, learning rates are based on the cumulative global PV market, of which the U.S. share has declined steadily from more than 30% in the mid-1990s to 11% in 2006. SolarDS does not forecast the global PV market, and the user must specify the U.S. fraction of the global PV market from 2008 to 2030.

Appendix C: Building Assumptions

Table C-1. Residential Roof Orientations

Orientation	Tilt	Azimuth	Flat 10%	4-sided Roof 45%	2-sided Roof 45%	Rooftop Fraction
1	0°	0°	100%	-	-	10%
2	25°	-90°	-	-	14%	6%
3	25°	-60°	-	-	14%	6%
4	25°	-30°	-	33%	14%	21%
5	25°	0°	-	33%	14%	21%
6	25°	30°	-	33%	14%	21%
7	25°	60°	-	-	14%	6%
8	25°	90°	-	-	14%	6%

Table C-2. Regional Roof Shading

Region (EIA Census + 4)	Shaded Fraction (%)
California	35
East North Central	55
East South Central	55
Florida	35
Mid Atlantic	55
Mountain	40
New England	60
New York	55
Pacific	40
South Atlantic	55
Texas	35
West North Central	45
West South Central	55

Table C-3. Commercial Roof Orientations

Orientation	Tilt	Azimuth	Rooftop Fraction[a]
1	0°	0°	10-50%
2	25°	0°	40-50%
3	25°	-30°	0-25%
4	25°	30°	0-25%

[a] Commercial roof orientation fractions vary by building type within the range specified.

Table C-4. Commercial PV Capacity by Building Type[a]

Building Type	Roof Area (1000 ft^2/building)	Unshaded Fraction (%)	Potential Roof Capacity (kW / building)
Education	15.59	80	112
Food Sales	4.88	80	35
Food Service	4.10	80	30
Inpatient	46.00	80	331
Outpatient	6.28	80	45
Lodging	12.65	80	91
Retail (other than mall)	7.66	80	55
Enclosed and Strip Malls	26.90	80	194
Office	6.02	80	43
Public Assembly	8.69	80	63
Public Order and Safety	9.20	80	66
Religious Worship	6.32	80	45
Service	5.35	80	38
Warehouse and Storage	13.79	80	99

[a] Represents unshaded commercial PV capacity by building type. This capacity is further reduced by the regional shading assumptions in Table C.2.

Appendix D: PV Financing Assumptions

The residential and commercial financing parameters are user input options in the SolarDS model. The reference case financing assumptions and the distribution of residential financing options are given below.

Table D-1. Residential Financing Inputs

Financing Parameters	New Construction	Retrofit Construction
Loan Rate	6.0% (real)	6.0% (real)
Loan Term	30 years	15 years

Table D-2. Distribution of Residential Financing

Down Payment Fraction	Tax Rate	Fraction of Households
20%	25%	40%
20%	33%	40%
100%	25%	10%
100%	33%	10%

Table D-3. Commercial Financing Parameters

Commercial Inputs	Value
Loan Term	15 years
Loan Rate	6.0% (real)
Down Payment Fraction	20%
IRR analysis period	25 years

Table D-4. Commercial Capital Depreciation Schedule (MACRS)

Year	Depreciation Fraction
1	20.00%
2	32.00%
3	19.20%
4	11.52%
5	11.52%
6	5.76%

Appendix E: PV Market-Penetration Curves

NEMS

The maximum annual adoption of PV by residential and commercial customers is calculated in NEMS as follows (EIA 2008a, 2008b):

$$Maximum\ Penetration_{New\ Construction} = Min\left\langle 0.75,\ \frac{0.30}{Payback\ Time\ (years)}\right\rangle \tag{E-1}$$

$$Maximum\ Penetration_{\text{Existing Buildings}} = Min\left\langle 0.005,\ \frac{0.30}{40 * Payback\ Time\ (years)}\right\rangle \tag{E-2}$$

Navigant, Inc.

The maximum PV market share from Navigant (Paidipati et al. 2008) was based on a customer survey of the potential residential adoption of a theoretical heat pump technology that is 20% more efficient than existing technology (Kastovich et al. 1982). The heat pump curve was decreased slightly, based on industry interviews. The Navigant study decreased the adoption rate on new construction for payback periods greater than three years because builders may be hesitant to include a technology with longer payback periods. Navigant curves result in significantly higher PV penetration than result from using NEMS curves for shorter payback periods.

R.W. Beck, Inc.

The maximum PV market share from R.W. Beck (2009) was calculated using an exponential increase in PV adoption with decreasing payback time:

$$Maximum\ Penetration_{All\ Buildings} = e^{-0.3 * Payback\ Time(years)} \tag{E-3}$$

This parameterization approximates the mean between the maximum PV market share curves assumed in the Navigant study and the original Kastovich et al. (1982) curve.

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14. ABSTRACT *(Maximum 200 Words)*
The Solar Deployment System (SolarDS) model is a bottom-up, market-penetration model that simulates the potential adoption of photovoltaics (PV) on residential and commercial rooftops in the continental United States through 2030. NREL developed SolarDS to examine the market competitiveness of PV based on regional solar resources, capital costs, electricity prices, utility rate structures, and federal and local incentives. This report provices details on the model, which uses the projected financial performance of PV systems to simulate PV adoption for building types and regions then aggregates adoption to state and national levels. The main components of SolarDS include a PV performance simulator, a PV annual revenue calculator, a PV financial performance calculator, a PV market share calculator, and a regional aggregator. The model simulates a variety of installed PV capacity for a range of user-specified input parameters. PV market-penetration levels from 15 to 193 GW by 2030 were simulated in preliminary model runs. SolarDS results are primarily driven by three model assumptions: (1) future PV cost reductions, (2) the maximum PV market share assumed for systems with given financial performance, and (3) PV financing parameters and policy-driven assumptions, such as the possible future cost of carbon emissions.

15. SUBJECT TERMS
SolarDS; photovoltaics; PV; PV capacity; PV systems; solar deployment system; adoption; residential; commercial; buildings; state; national; United States; model; model results; market model; market penetration; market competitiveness; regional solar resources; solar capital costs; electricity prices; utility rate structures; federal incentives; local incentives; annual revenue; financial performance calculator; market share; cost reductions; financing parameters

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