

Chapter 5 – Economics of Solar Electricity Generation

In Chapter 4 we presented data on the total investment cost of residential- and utility-scale photovoltaic (PV) installations, and in Appendix D we presented data on the investment cost of utility-scale concentrated solar power (CSP) plants. In this chapter we first use those data, along with other information, to compute estimates of the cost of electricity generated at: (1) a 20-megawatt (MW) utility-scale solar PV project; (2) a 7-kilowatt (kW) residential rooftop PV installation, and (3) a 150-MW utility-scale CSP project. We consider hypothetical facilities at two U.S. locations for which reliable insolation data are available: the town of Daggett in southern California’s San Bernardino County and the city of Worcester in central Massachusetts.ⁱ The southern California location is much sunnier on average than the Massachusetts location: Daggett receives approximately 5.8 kilowatt-hours of solar radiation per square meter per day (kWh/m²/day) whereas Worcester receives approximately 3.8 kWh/m²/day. Together, this pair of sites helps illustrate the range of costs produced by geographic variation. We assume identical investment costs for the two locations, but account for differences in insolation and other location-specific factors discussed below. We then compare generation costs at these sites to each other and to the cost of electricity from

a new natural gas combined cycle plant with and without a carbon tax, where the carbon tax is set equal to the social cost of carbon dioxide (CO₂) emissions used by federal agencies in recent regulatory impact analyses.¹

Data on average hourly wholesale electricity prices in the two locations are used to shed light on the average value of power generated by our hypothetical solar installations, taking wholesale prices as given.ⁱⁱ We then look at the impact of a number of factors on the cost of solar electricity from our hypothetical facilities. To highlight the importance of balance-of-system (BOS) costs for PV installations, we compute generation costs assuming that module prices decline by 50%. And because, as we stress in Chapter 4, the residential PV market is immature, we present estimates of levelized cost assuming that residential BOS costs in the United States fall to a level commensurate with those in Germany. Finally, we analyze the effects of the main federal subsidies on generation costs in the United States. As discussed below, it was not possible for us to measure the effects of state-level policies (known as “renewable portfolio standards”) that oblige utilities in both California and Massachusetts to acquire a certain percentage of their electricity from renewable sources, or

ⁱOur insolation data are from the National Renewable Energy Laboratory (NREL), which provides hourly insolation data for individual years (1991–2010) and for the typical meteorological year for 1,454 locations in the United States through the National Solar Radiation Database. Insolation and local meteorological conditions are either directly measured at ground stations or modeled based on a combination of satellite and ground-based data. Here we select locations designated as Class I stations, which have a complete record of solar and meteorological data for all hours for 1991–2010 and the highest-quality modeled solar data. From this we constructed a series for the typical year.

ⁱⁱFor our southern California data, we used hourly day-ahead locational marginal prices from the California Independent System Operator (CAISO) for the two major transmission intersections closest to Daggett, and averaged them. We are indebted to Gavin McCormick and Anna Schneider at WattTime for providing this data. For our central Massachusetts data, we used Independent System Operator-New England (ISO-NE) hourly day-ahead locational marginal prices for West-Central Massachusetts, made available in convenient form by GDF SUEZ Energy Resources.² In both cases, we constructed a series for a typical year by averaging over the years 2010–2012.

the effects of an array of additional state- and local-level renewable energy policies in these and other states.

Before turning to the details and results of our quantitative analysis, it is useful to begin with a general discussion of how the cost and value of electricity from particular generating facilities can be measured.

5.1 MEASURING THE COST AND VALUE OF SOLAR ELECTRICITY

A metric that is widely used to compare alternative generating technologies is the levelized cost of electricity (LCOE).ⁱⁱⁱ Given a stream of capital and operating costs incurred over the life of a facility and a corresponding stream of electricity production, the LCOE is defined as the charge per kWh that implies the

One important limitation is that the LCOE implicitly values all kilowatt-hours of power produced the same, regardless of when they are generated. But the incremental cost of meeting electricity demand is higher during peak periods.

same discounted present value as the stream of costs. The discounting is done using a cost of capital appropriate to the type of project being considered. Put another way, the LCOE is the minimum price a generator would have to receive for every kWh of electricity output in order to cover the costs of producing this power, including the minimum profit required on the generator's investment. More detail on the calculation of LCOE is presented in Appendix E.

Renewable electricity generated in peak hours is more valuable than electricity generated in off-peak hours.

The Cost of Capital

A critical component of the LCOE is the cost of capital. As described in detail in Appendix E, our basic analysis assumes a weighted average nominal cost of debt and equity capital of approximately 6.67%, along with an expected inflation rate of 2.5%.^{iv} A 6.67% nominal cost of capital may seem high, given the extremely low interest rates that prevailed as this report went to press, but it is likely to be quite reasonable in more normal times.

Value versus Levelized Cost

Estimating the LCOE is only a starting point for evaluating the economics of a solar project, or of any other power generation project. One important limitation is that the LCOE implicitly values all kilowatt-hours of power the same, regardless of when they are generated. But the incremental cost of meeting electricity demand is higher during peak periods, like hot summer afternoons, than during off-peak periods, like comfortable spring evenings. During peak periods, incremental demand is typically met by employing fossil-fuel generating units that are operated for only a few hours a year. Since it is expensive to keep large amounts of capital idle most of the time, these units generally have low capital costs and, as a consequence, relatively high marginal costs. Thus renewable electricity generated in peak hours is more valuable than electricity generated in off-peak hours because it permits a larger reduction in fossil generation costs at the margin. In competitive wholesale power markets, this fact is at least partially reflected in higher prices for electricity during peak hours as compared to prices during off-peak hours. The price of electricity also varies over the course of the calendar year for

ⁱⁱⁱSee, for example, NREL.^{3,4}

^{iv}Background on the weighted average cost of capital can be found in, for example, Brealey, Myers, and Allen.⁵

similar reasons. Other limitations of the LCOE arise when this metric fails to reflect a project's ability to provide capacity to meet uncertain demand, its ability to provide ramping capability, and other distinguishing attributes, some of which are discussed in more detail in Chapter 8.

To keep our analysis simple and because the value of the time profile of generation is so critical for a non-dispatchable resource like solar, we address only the average-price limitation of the LCOE.^v Specifically, we use the time profile of wholesale electricity prices as the best available measure of the time profile of the social value of power. If more solar generation occurs when the hourly location-specific price is above average than when the price is below average, solar generation is more valuable per kWh than baseload generation. In this case, a solar plant selling at hourly location-specific prices would be viable at a lower unweighted average price than a baseload power plant with the same LCOE.^{vi} Hirth introduced the term “*value factor*” to denote the ratio of a facility's output-weighted average price to its corresponding unweighted average price.¹²

Dividing a facility's LCOE by its value factor produces what we call the *value-adjusted* LCOE — in other words, it gives the minimum unweighted average price per kWh that would cover the generator's cost, given the observed temporal pattern of prices.

At least at low levels of solar penetration, one would expect solar facilities to have value factors above one, since wholesale prices tend to be higher in the day than at night. For our hypothetical PV facilities, we computed value factors using the typical-year insolation data described in Footnote i and the typical-year hourly price data described in Footnote ii. The value ratio for the southern California location was 1.13 and for the central Massachusetts location was 1.10. These values are roughly consistent with results obtained by Schmalensee (forthcoming)¹³ using 2011 data.^{vii} For the CSP facilities, without taking advantage of energy storage, the value ratio for the southern California location was 1.08; for central Massachusetts it was 1.11. This differs from the value ratio for our hypothetical PV project primarily because a certain amount of

^vThe U.S. Energy Information Administration (EIA) recently introduced another metric, the levelized avoided cost of energy (LACE) that can be used along with the LCOE to address this same limitation. See the presentation by Chris Namovicz.⁶ See also two papers available at the same website.^{7,8} LACE is closely related to the value factor defined below, except that it includes capacity payments available through wholesale markets. The Minnesota Department of Commerce, Division of Energy Resources recently undertook an alternative, similarly inspired effort to augment the LCOE.⁹

For a recent, much more ambitious — and controversial — attempt to quantify all the costs and benefits of a set of generating technologies that includes solar PV, see Charles R. Frank, Jr.¹⁰ and Amory Lovins.¹¹

^{vi}Output from solar facilities is often sold under fixed-price, long-term contracts, not on the day-ahead hourly market. Absent a subsidy, however, one would not expect a buyer to pay more under a long-term contract than the (discounted) expected value of future hourly prices, since the buyer is bearing all the price risk. Indeed, many solar power purchase agreements adjust payments according to the hours in which power is actually delivered, specifying a higher price for power in some hours than in others. In any case, the value of a solar facility's output will surely influence the price it will command in the market.

^{vii}An earlier version is Schmalensee's 2011 value factors, which are calculated for nine PV facilities, three of which were at unknown locations in California and three of which were at unknown locations in New England.¹⁴ All nine solar value factors were above one. (In contrast, 22 of 25 value factors for wind generators were below one.) Value factors for the three California PV plants clustered tightly around the average of 1.13, which is exactly the value factor we find here for our southern California location at Daggett. For the three New England plants, Schmalensee found value factors of 1.18, 1.11, and 1.08, for a combined average of 1.12. This is higher than the 1.10 value factor we find here for our central Massachusetts location at Worcester, but well within the range of the data.

within-day inertia in the timing of electricity production is inherent in CSP, since the temperature of the medium that stores solar-derived thermal energy is relatively insensitive to short-term fluctuations in insolation.

In a system with lots of solar generators that can profitably sell power in the short run at almost any positive price, wholesale prices might be lower at noon than at midnight.

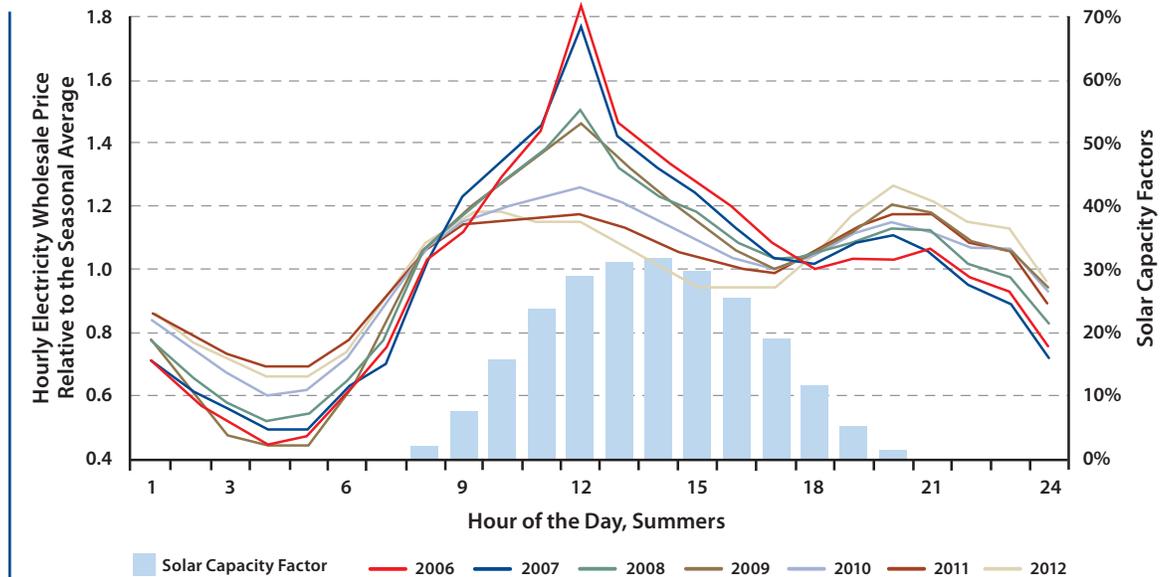
However, taking optimal advantage of energy storage opportunities that would allow a CSP facility to accumulate thermal energy during hours of low electricity prices and generate at maximum capacity during hours of high electricity prices (so long as either insolation or stored thermal energy is available), the value ratios for the hypothetical CSP facilities increase to 1.12 and 1.16 at the southern California and central Massachusetts locations

respectively. We use these higher values to calculate a value-adjusted LCOE for the CSP facilities.

Unfortunately, the value factor for any solar project is likely to decline dramatically with increased penetration of solar generation in the overall power mix as a result of basic supply and demand dynamics. Simply put, increasing the amount of zero-marginal-cost generation available during hours of high insolation will drive the price down in those hours. In a system with lots of solar generators that can profitably sell power in the short run at almost any positive price, wholesale prices might be lower at noon than at midnight.

Hirth finds considerable evidence for declining value factors in European data over several years of increasing solar penetration.¹² Figure 5.1, taken from Hirth, shows how the daily electricity price structure in Germany

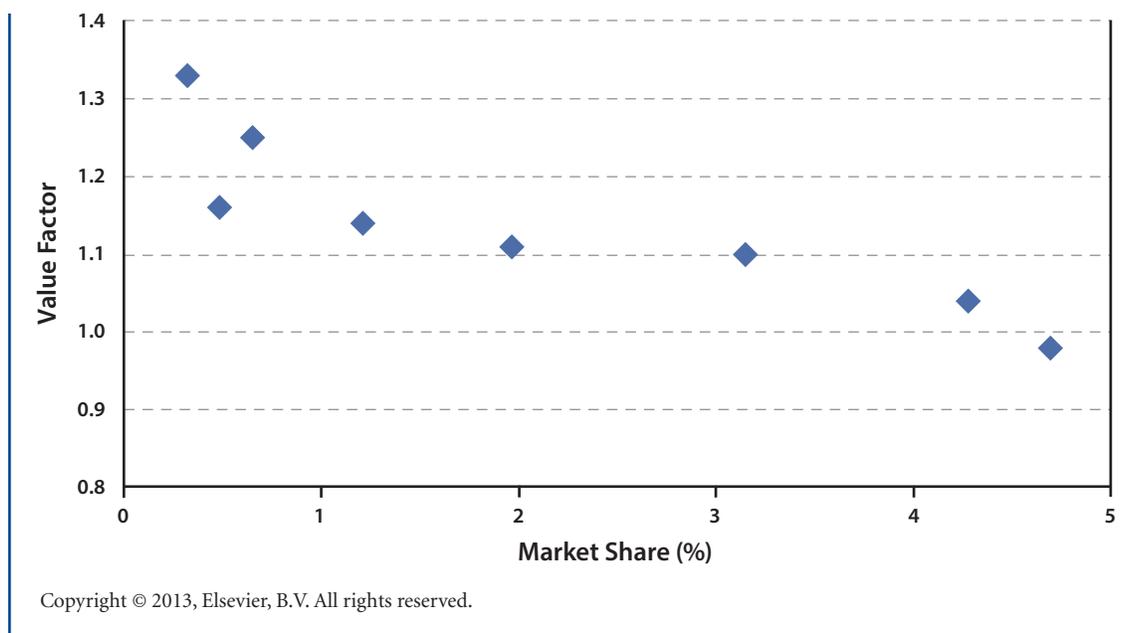
Figure 5.1 Summertime Hourly Electricity Wholesale Prices Relative to Seasonal Average Price in Germany 2006–2012



Note: Lines show hourly wholesale prices relative to the seasonal average price for different years for the period 2006–2012, a time when installed solar capacity in Germany increased by 30 GW. The bars show the time profile of solar generation in Germany measured as the capacity factor for installed generation for 2006 to 2012.¹²

Copyright © 2013, Elsevier, B.V. All rights reserved.

Figure 5.2 Value Ratio for Solar Generation in Germany with Changing Market Share¹²



during summer hours changed between 2006 and 2012 as solar capacity increased by 30 gigawatts (GW). In 2006, the price at noon was 80% higher than the average price, while in 2012 it was only about 15% higher. Consequently, the value ratio for solar power declined dramatically over the same time. Figure 5.2, also taken from Hirth, shows this decline as a function of solar generation’s increasing market share. It follows that currently observed value factors provide only a rough upper bound to expected future value factors for intermittent generators in the same market, using the same technology.

5.2 UTILITY-SCALE PV

Our analysis begins with the solar electricity generating technology that enjoys the most favorable economics today. As noted above,

we consider hypothetical solar PV plants in California and Massachusetts with a nameplate direct current (dc) peak power rating of 20 MW.^{viii} The project life is assumed to be 25 years, with output from the modules degrading at a rate of 1% per year, so that output in the 25th year equals approximately 79% of output in the first year.

Following Chapter 4, we assume a fully loaded module cost (i.e., including associated installer overhead) of 65 cents per watt (\$0.65/W), which — when multiplied to reflect a 20 MW, utility-scale facility — yields an up-front investment cost of \$13 million for the modules. Besides the cost of the modules, the complete installation requires the purchase of inverters, brackets, and wiring, as well as additional expenditures on engineering, construction and project management, sales taxes on materials,

^{viii}These projects are assumed to be ground-mounted, fixed-tilt arrays using multicrystalline silicon PV modules with a dc peak power of 310W and a power conversion efficiency of 16%. The direct-current-to-alternating-current (dc-to-ac) derate factor of approximately 0.86 was estimated following NREL. The total dc-to-ac derate factor of 0.86 includes inverter and transformer inefficiencies (0.977), module-to-module mismatch (0.980), blocking diode and connection losses (0.995), dc wiring losses (0.980), ac wiring losses (0.990), soiling loss (0.950), and system downtime (0.980). We do not include losses due to nameplate rating error, shading effects, and tracking error. For further discussion, see NREL.¹⁵

and other charges. Together these are known as BOS (balance-of-system) costs. Again following Chapter 4, we assume a BOS cost of \$1.15/W. At the 20 MW scale, this yields an additional up-front investment cost of \$23 million. Together, the module and BOS costs add to a total investment of \$36 million. Module cost and BOS costs account for 36% and 64%, respectively, of this total.

A given project may also incur additional indirect costs associated with grid integration. These indirect costs depend on many factors.

After the initial investment, our hypothetical project incurs annual operation and maintenance (O&M) costs, which we assume equal \$0.02/W per year.¹⁶ We assume O&M costs escalate with inflation. So, in the first year of operation, the O&M cost is \$410,000. In addition, the project's inverters will need to be replaced in the twelfth year of operation at a cost of \$3 million (before accounting for inflation).

Investment cost plus O&M costs constitute all direct costs. However, a given project may also incur additional indirect costs associated with grid integration. These indirect costs depend on many factors, including the institutional rules governing the region where the project is located. For example, the intermittency of the solar resource may force the grid manager to maintain additional flexible resources to ensure system reliability, and some of these costs might be imposed on the solar facility.^{ix} In addition, depending on the location of the project and applicable cost allocation rules, there may be costs associated with installing a transmission line to deliver power from the solar facility to the existing grid. Our calculations do not include any charges for these or any other indirect costs.

We apply the same investment cost and O&M cost assumptions to both the southern California and the central Massachusetts plants. Given the typical insolation at our southern California location, this plant should generate approximately 36,000 megawatt-hours (MWh) of electricity in the first year of operation, with output in subsequent years declining gradually over the life of the project. In contrast, lower levels of insolation at the central Massachusetts location mean that the same plant can be expected to generate approximately 24,000 MWh in its first year of operation, one-third less electricity than the southern California project using the same equipment. Because of this difference in output, the LCOE of the central Massachusetts project is 15.8 cents per kilowatt-hour (¢/kWh), 50% higher than the 10.5¢/kWh LCOE of the southern California project. These figures assume no subsidies. Figure 5.3 provides a convenient visual display of these LCOEs, together with some of the further results discussed below. These results are also summarized in Table 5.1, which appears at the end of the chapter.

As described above, we calculated value factors for the California and Massachusetts locations to account for the fact that peak solar output is likely to occur at times when demand is high and prices for electricity are above average. Dividing by these value factors lowers the LCOE of the southern California project by 12% and lowers the LCOE of the central Massachusetts project by 9% (see Table 5.1). As we noted previously, value factors will tend to decline as the share of solar energy in the overall generation mix increases. This in turn would raise the value-adjusted LCOEs of future solar projects. At a certain level of penetration, value factors for solar generators are likely to decline below 1, so that the value-adjusted LCOE rises above the unadjusted LCOE.

^{ix}See Chapter 8 of this report and Gowrisankaran, Reynolds, and Samano.¹⁷

One way to evaluate these LCOEs for utility-scale PV is to compare them against the LCOEs for competing technologies. Currently, the most prominent competitor for investment in new electricity-generating capacity is natural gas combined cycle (NGCC) technology. The U.S. Energy Information Administration (EIA) estimates the LCOE of new NGCC plants at 6.66¢/kWh, less than two-thirds the estimated LCOE for our hypothetical California project.^x

This figure does not take into account any spillover costs associated with the NGCC plant's CO₂ emissions, however. Adding a charge of \$38 per metric ton of CO₂, consistent with the "social cost of carbon" used in recent federal-level regulatory analyses, increases the LCOE for the natural gas plant by 1.42¢/kWh, bringing its total LCOE to 8.08¢/kWh — still well below the estimated LCOE for our two solar projects.^{xi} Figure 5.3 places this benchmark against the LCOEs for utility-scale PV. In order for the LCOE of the utility-scale PV project to be equal to the LCOE of natural gas fired generation, the CO₂ charge would have to rise to \$104 per ton.

To explore the importance of BOS costs, we recalculate the LCOE for our two PV projects assuming that the module cost is reduced by

In order for the LCOE of the utility-scale PV project to be equal to the LCOE of natural gas fired generation, the CO₂ charge would have to rise to \$104 per ton.

50%. This change reduces the LCOE for the southern California and central Massachusetts projects to 8.9¢/kWh and 13.4¢/kWh, respectively. These results are included in Table 5.1. Thus, even in a scenario that assumes a 50% reduction in module cost, a carbon tax consistent with the federal government's estimate of the damages caused by CO₂ emissions, and a value factor that is not depressed by high levels of solar penetration, utility-scale PV would be competitive with NGCC in southern California, but not in central Massachusetts. Clearly reductions in BOS cost could make an enormous difference to the LCOE for PV generators.

^xThis is EIA Levelized Cost of New Generation Resources.¹⁸ Table 5.1 gives a total cost inclusive of transmission equal to 6.63¢/kWh in 2012\$ for plants entering service in 2019. We subtract the transmission cost to arrive at a busbar cost, and then we escalate the figure to 2014\$ using the Bureau of Economic Analysis (BEA) price index for GDP, gross private domestic investment, fixed investment, non-residential. As discussed in Appendix E, our estimates of LCOE should be comparable to those calculated by the EIA, given identical inputs such as the cost of equipment and the price of fuel. We use a slightly lower cost of capital, which, if it were applied to the other EIA inputs would slightly decrease EIA's calculated LCOE for the NGCC plant. The EIA also reports an LCOE of 12.88¢/kWh for utility-scale solar PV, excluding transmission cost and escalated to 2014\$. This figure falls between our two estimates reported above.

The OpenEI database¹⁹ sponsored by the U.S. Department of Energy, NREL, and a number of private firms reports a median LCOE for combined cycle gas turbine (CCGT) plants of 5¢/kWh.

The California Energy Commission (CEC) reports a mid-range estimated LCOE for NGCC of 15.76¢/kWh. This figure assumes a typical capacity factor of 57%, whereas the EIA figure assumes a high, baseload capacity factor of 87%. Applying the higher capacity factor to CEC's other assumptions would reduce CEC's calculated LCOE by one-third, to just over 10¢/kWh.

^{xi}Based on the NGCC plant emitting 53.06 million metric tons of CO₂ per quadrillion Btus, and on a heat rate of 7.050 Btu/kWh, as per the EIA.²⁰ An interagency working group of the U.S. government produces estimates of the social cost of carbon under a range of assumptions; see Footnote ii above for the publication. Looking at their central case (3% discount rate), they report figures starting at \$32 per ton CO₂ and increasing to \$71 per ton CO₂ in 2050, all denominated in 2007 dollars. If we take the \$36-per-ton figure for 2014 and translate it from 2007\$ into 2014\$ to match our other data using the BEA price index for GDP, gross domestic product, we get the \$38-per-ton-CO₂ figure used in this analysis.

FINDING

At current and expected natural gas prices, using solar energy to generate electricity at most locations in the United States is considerably more expensive than using natural gas combined cycle technology, even if natural gas plants are subject to a carbon tax equal to the “social cost of carbon,” as determined by the U.S. government, and even giving credit for the current value of solar electricity. Under these conditions, a further 50% reduction in module costs would make utility-scale PV competitive in California, but not in Massachusetts.

5.3 RESIDENTIAL-SCALE PV

To explore the economics of residential-scale PV, we consider hypothetical rooftop installations in our southern California and central Massachusetts locations with a nameplate DC peak power rating of 7 kW.^{xii}

Following Chapter 4, we assume a module cost of \$0.65/W and a BOS cost of \$2.60/W. This yields a total up-front investment cost of \$22,750 for a 7 kW installation, of which \$4,550 (20%) consists of module costs and \$18,200 (80%) consists of BOS costs.

After the initial investment, we assume annual O&M costs start at \$0.02/W per year and escalate with inflation. This means O&M costs in the first year of operation total \$144 and rise with inflation thereafter. In addition, we assume

that inverters will need to be replaced in the twelfth year of operation at a cost of approximately \$2,030 before adjusting for inflation.

As with our analysis of utility-scale projects, indirect costs — such as costs for the flexible reserve capacity needed to accommodate intermittent generation or for reinforcements of the local distribution network to handle power flows from solar-generating residential customers back to the grid (discussed in Chapter 7) — are not included here.

We apply the same capital cost assumptions to both the southern California and central Massachusetts projects. Given typical insolation, the southern California rooftop installation should generate approximately 11.9 MWh in the first year of operation, with output declining gradually thereafter over the life of the project. In contrast, the same installation in central Massachusetts should generate approximately 7.9 MWh of power in its first year of operation. This is one-third less than the southern California project and is due to lower insolation in the Massachusetts location. Reflecting this difference in output, the LCOE for the central Massachusetts project is 28.7¢/kWh, 50% higher than the LCOE for the southern California project at 19.2¢/kWh. These values are shown in Figure 5.3 and appear in Table 5.1.

As we noted in Chapter 4, residential BOS costs in the United States are much higher than in Germany. Some of this difference reflects the relative immaturity of the U.S. residential PV market; some reflects the effect of local rather than national policies on issues such as

^{xii}We assume roof-mounted, fixed-tilt arrays using multicrystalline silicon PV modules with a dc peak power of 310 W and a power conversion efficiency of 16%. A dc-to-ac derate factor of approximately 0.81 was estimated, although a reduced inverter/transformer efficiency is assumed. The total dc-to-ac derate factor of 0.81 includes inverter and transformer inefficiencies (0.920), module-to-module mismatch (0.980), blocking diode and connection losses (0.995), dc wiring losses (0.980), ac wiring losses (0.990), soiling loss (0.950), and system downtime (0.980). We do not include losses due to nameplate rating error, shading effects, non-optimal roof alignment, or tracking error. See NREL for further discussion.¹⁵

permitting processes and interconnection standards. To reflect the possibility that residential BOS costs in the United States could be substantially reduced over time, we recalculate the LCOE using a BOS cost of \$1.34/W — nearly 50% lower than the \$2.60/W BOS cost assumed in our base case. With this reduction in BOS costs, the LCOE for a 7 kW rooftop PV installation would fall to 12.0¢/kWh and 18.0¢/kWh in California and Massachusetts, respectively. These figures, which are included in Table 5.1, assume no subsidies.

FINDING

Utility-scale PV is likely to remain much less expensive than residential-scale PV, even in the face of foreseeable reductions in the balance-of-system costs associated with residential-scale PV.

Even in the absence of explicit subsidies, for most homeowners the relevant comparison is not between the LCOE of residential PV and the LCOE of other generation technologies, or between the LCOE of residential PV and the wholesale price of electricity. Rather the relevant comparison for most homeowners is to the retail price of electricity delivered over the grid. This retail price typically contains a number of additions on top of the wholesale price, including charges to cover the costs of the transmission and distribution systems. These transmission and distribution costs, though they do not vary with the level of electricity consumed (except when new construction is required), are overwhelmingly recovered from customers in the United States through a per-kWh charge. Because retail prices per kWh, which include these charges, exceed wholesale prices — often by a substantial margin — it is possible for a residential PV system to make economic sense for a homeowner even if its levelized cost for electricity is well above the wholesale price paid to utility-scale generators.

Moreover, in some cases, the per-kWh rate for residential customers increases with total consumption, so that heavier users face a higher rate — a higher marginal cost. In some locations, the highest rates charged to retail customers can make residential PV economically competitive, even at current LCOEs. In other locations, anticipated cost reductions in coming years will make residential PV systems competitive for high marginal rate customers, assuming that the rate structure remains as it is today. For example, the highest marginal rates currently charged by California's three major distribution utilities range from 21.8¢/kWh to 35.9¢/kWh, while the highest marginal rate for retail customers in Oahu, Hawaii, is 24.7¢/kWh.^{21,22,23,24}

Net metering pays distributed generators a much higher price for power than grid-scale generators receive.

The difference between wholesale and retail costs of power is central to the growing debate about net metering regulations and about the broader question of tariff rules for transmission and distribution charges. A net metering system charges the homeowner for the net quantity of electricity consumed — in other words, total consumption less total generation. This means, in effect, that the utility is paying for electricity generated by the homeowner at the retail rate, in contrast to utility-scale generation facilities, which receive the wholesale price. Because the retail rate includes charges for the cost of the transmission and distribution system (on top of a charge for the power consumed), net metering pays distributed generators a much higher price for power than grid-scale generators receive. As discussed in the MIT

Because retail prices per kWh exceed wholesale prices, it is possible for a residential PV system to make economic sense for a homeowner even if its levelized cost for electricity is well above the wholesale price paid to utility-scale generators.

CSP plants can be designed to allow operators to delay the use of thermal energy from the solar field by redirecting it to a storage system.

Future of the Electric Grid study,²⁵ “net metering policies provide an implicit subsidy to all forms of distributed generation that is not given to grid-scale generators.” Chapter 7 of this report provides a more detailed analysis of the impact of distributed solar generation on the costs of the transmission and distribution system.

5.4 UTILITY-SCALE CSP

This section discusses the economics of two hypothetical utility-scale CSP plants using the same southern California and central Massachusetts locations described in the previous sections. Both plants employ the Power Tower technology described in Chapter 3 and are designed to have a nominal net generation capacity of 150 MW.^{xiii} The System Advisor Model (SAM) developed by the U.S. Department of Energy’s National Renewable Energy Laboratory (NREL) is used to simulate the operation of the CSP plants.²⁶ More information regarding the design of the CSP plants is provided in Appendix D.

To account for output interruptions, we apply a system availability factor of 96%. Because of the nature of CSP plants, however, production capacity is not expected to decline over time as would be the case for PV plants. Our assumptions for CSP capital and operating costs are based on existing engineering estimates available in the literature.^{27,28} We then adjust these cost estimates to reflect the size of our hypothetical plants using common engineering practices and convert to

2014 dollars using the Chemical Engineering Plant Cost Index.²⁹ Appendix D provides further detail regarding the technical specifications and cost assumptions used in our analysis.

CSP plants can be designed to allow operators to delay the use of thermal energy from the solar field by redirecting it to a storage system (see Chapter 3). This makes it possible to deliver a more even stream of energy over time to the facility’s power generation components, raising their capacity factor and allowing for a lower LCOE. Energy storage capability can also make it possible to delay power generation to periods later in the day when electricity prices are higher. This raises both the capacity factor and the facility’s value factor. The cost of energy storage includes the cost of storage tanks and pumps, as well as costs associated with having a larger solar field capable of providing energy to both power generation and storage systems.

The CSP plant designs considered in this chapter are optimized to minimize their LCOEs. Our hypothetical plants in southern California and central Massachusetts have 11 and 8 hours of storage, respectively — measured assuming operation at full load. This difference mainly reflects the higher insolation of the California location, which makes it cheaper to produce thermal energy for storage, as well as for generation. Obviously, however, the typical daily pattern of prices will affect the value of storage.

For the southern California plant, we estimate the LCOE (with no subsidies) at 14.1¢/kWh. For the central Massachusetts plant, we estimate the no-subsidy LCOE at 33.1¢/kWh, or

^{xiii}In both plants, circular arrays of heliostats reflect and focus the sunlight onto the top of the tower where an External Receiver accepts the reflected sunlight and transfers the thermal energy to a Heat Transfer Fluid (HTF). A mixture of 60% NaNO₃ and 40% KNO₃ is used as the HTF. The size of the solar field and the tower dimensions are optimized to the satisfaction of plant requirements. No fossil boiler (neither backup nor supplemental) is considered for the plants. In addition, to minimize water requirements, an air-cooled steam condenser is assumed for both plants. To improve the economics of the plants, a two-tank thermal energy storage (TES) system is considered for each plant. The size of the storage system is optimized to minimize the LCOE of the plant. Other technical specifications of the plants follow those suggested by the engineering firm WorleyParsons and are used as default values in SAM.

more than double the cost of power using the same technology optimized for the southern California location. These results are displayed in Figure 5.3 and included in Table 5.1. The difference in LCOE for the two locations is more dramatic in the CSP case than in the utility-scale PV case because of a greater difference in direct insolation (relative to total insolation) between the two sites. As noted in Chapter 3, CSP plants can only make use of direct insolation, which is lower as a fraction of total insolation in central Massachusetts due to a greater abundance of clouds.

Dividing by value factors that incorporate the potential to delay generation using the CSP plants' thermal storage capability produces a value-adjusted LCOE at the southern California project that is 12.6¢/kWh (or 11% less than the baseline value); the value-adjusted LCOE at the central Massachusetts project is 29.5¢/kWh (also 11% less than the baseline value), as shown in Table 5.1. At higher levels of solar penetration, the value factors for CSP plants will decline, but because of the flexibility provided by storage, this decline should be less steep than for PV plants.

FINDING

Currently CSP generation is slightly more expensive than utility-scale PV in regions like California that have good direct insolation. It is much more expensive, however, in cloudy or hazy areas that experience relatively little direct solar irradiance, like Massachusetts. Adding energy storage and optimally deploying this capability reduces the LCOE of CSP plants and enables CSP generators to focus production on periods when electricity is most valuable.

5.5 SUBSIDIES

A wide range of subsidies has been used in recent years to encourage the deployment of solar generation technologies in the United States. The federal government has provided many of these subsidies, while state and local governments have provided many others.^{xiv}

A wide range of subsidies has been used in recent years to encourage the deployment of solar generation technologies in the United States.

Federal Tax Preferences

Currently the U.S. government offers two important tax preferences at the federal level: an investment tax credit (ITC) and an accelerated depreciation schedule, for tax purposes, for solar energy projects. Specifically, such projects can use a 5-year Modified Accelerated Cost Recovery System (MACRS) schedule instead of the 15-year schedule that is applied to other generation technologies with similar lives.

Over the last several decades, solar power generation has often qualified for an investment tax credit of one sort or another. The Energy Policy Act of 2005 increased the ITC from 10% of the qualifying cost of a project to 30% through 2007. In 2008, the Emergency Economic Stabilization Act extended the 30% ITC through 2016. Absent new legislation, the credit reverts back to 10% in 2017. Under the current ITC, 30% of the cost of a solar installation can be taken as a credit against taxes owed. The developer must then reduce the depreciable basis of the installation. Under current regulations, the basis is reduced by one-half of the credit — thus, the depreciable basis is 85% of the investment cost.

^{xiv}These subsidies are discussed in more detail and evaluated in Chapter 9 of this report. A complete list of references is available at DSIRE, a website maintained by North Carolina State University for the U.S. Department of Energy.³⁰

The Tax Reform Act of 1986 established current MACRS depreciation schedules and specified the use of a 5-year schedule for solar, geothermal, and wind generation facilities. The accelerated depreciation reduces a project's taxable income in the first five years, while increasing its taxable income in the sixth to sixteenth years of operation. Although the project's total taxable income over all years remains the same, an accelerated depreciation schedule has the effect of pushing tax payments out into later years when the same dollar has a lower present value. This lowers the project's LCOE.

As noted in Chapter 4, subsidies in the form of tax credits can sometimes only be used efficiently by a small subset of corporate entities that have substantial taxable profits. This subset does not include most developers of solar projects. Instead, to tap these subsidies solar developers often have to contract with entities that can efficiently use the ITC in what is loosely called the “informal, over-the-counter” tax equity market. Depending on the state of that market, a solar developer may have to pay a hefty share of the value of the ITC to the tax equity partner. This leaves less to the solar developer and reduces the effectiveness of the subsidy: less solar technology deployment is supported per dollar of subsidy cost to taxpayers. The share of value captured by the tax equity market creates a wedge between the value and the cost of the tax subsidy. By reducing the effective value of every dollar of subsidy it increases the cost (to taxpayers) of achieving the purpose of the subsidy.

It is difficult to pin down the size of this wedge in the case of a subsidy like the federal ITC. One recent study concluded that renewable energy developers captured only 50% of the value of the ITC, implying that a direct cash subsidy could support the same level of deployment at half the cost of the current tax credit subsidy.³¹

One recent study concluded that renewable energy developers captured only 50% of the value of the ITC.

The state of the U.S. economy plays a strong role in determining the size of the wedge. For example, the financial crisis of 2008 and the ensuing recession so dramatically reduced the available pool of tax equity financing that the ITC was widely viewed as completely ineffective. This motivated the temporary creation of a cash grant option in lieu of the ITC as a part of the Obama Administration's economic stimulus legislation, the American Recovery and Reinvestment Act of 2009. While the tax equity market has at least partially recovered in recent years, there still remains a significant wedge between cost and value.

Assuming developers capture 50% of the federal ITC subsidy, the LCOE for the hypothetical, southern California utility-scale PV project analyzed in this chapter is 8.4¢/kWh. In that case, existing federal tax preferences have lowered the LCOE by 2.1¢/kWh or 20%. For our central Massachusetts utility-scale PV project, the LCOE — again assuming developers capture 50% of the federal ITC subsidy — is 12.7¢/kWh. In that case, tax preferences have lowered the LCOE by 3.1¢/kWh (likewise 20%). For our residential PV and utility-scale CSP examples, current federal tax preferences lower

the LCOE by 21%.^{xv} These values are displayed in Figure 5.3 and in Table 5.1. If, somehow, the federal ITC subsidy were 100% effective, it would lower these LCOEs further still, as displayed in Table 5.1: for our southern California utility-scale PV project, the LCOE would fall to 6.8¢/kWh; for our central Massachusetts utility-scale PV project, the LCOE would fall to 10.1¢/kWh; for our southern California residential-scale PV project, the LCOE would fall to 12.0¢/kWh; for our central Massachusetts residential-scale PV project, the LCOE would fall to 18.0¢/kWh; for our southern California CSP project, the LCOE would fall to 10.2¢/kWh; and for our central Massachusetts CSP project, the LCOE would fall to 23.9¢/kWh.

State and Local Incentives — Renewable Portfolio Standards

Individual state and local governments employ a wide array of tools to encourage the deployment of various renewable generation technologies.³⁰ These tools include direct cash incentives, net metering policies, tax credits and tax incentives, loan programs and favored financing arrangements, programs to facilitate permitting and other regulatory requirements,

and many others. Both California and Massachusetts provide cash payments to solar generators; in California these payments start at 39¢/kWh for large PV facilities. Along with 41 other states and the District of Columbia, California and Massachusetts have also implemented net metering policies. These compensate residential PV generation at the retail price of power, which is often a significant multiple of the wholesale price at which utility-scale generators are compensated and thus provide a differential subsidy to residential PV. For instance, during 2013, the retail rates of Pacific Gas and Electric, which serves the Bay Area in northern California ranged up to 36¢/kWh,²³ while the weighted average wholesale price of electricity at the northern California hub of the California Independent System Operator (CAISO) averaged 4.4¢/kWh.^{xvi} Finally, both California and Massachusetts exempt solar generation equipment from sales and property taxes, and both have a variety of other programs in place to support deployment of solar (and other renewable) generation. Even if the analysis were confined to just one or two states, it would be an enormous task to measure the impact of all the renewable energy support policies in effect at any particular time.

^{xv}While the costs of the tax equity market lower the subsidy value captured by the developer, other factors may raise it. In particular, developers of residential solar installations must estimate the fair market value (i.e., the basis) for the purpose of calculating the ITC, and some analysts have claimed that the reported basis is often too high. One published estimate³² puts the premium of the reported to actual cost in the neighborhood of 10%. This is comparable to a 10% increase in the value of the subsidy.

^{xvi}This was computed as the average of the weighted average prices reported by EIA for hub NP-15.³³ Net metering is discussed further in Chapter 9 of this report.

Currently 29 states, including California and Massachusetts, and the District of Columbia have RPS programs.

One widely employed support policy is the renewable portfolio standard (RPS), which requires retail providers of electricity, generally called load-serving entities (LSEs) to generate or purchase a minimum fraction of their electricity from renewable sources.^{xvii} Currently 29 states, including California and Massachusetts, and the District of Columbia have RPS programs. Solar generation can be used to satisfy the RPS obligation in all these jurisdictions, and 17 of the 30 programs currently in place have additional provisions that specifically favor solar electricity. For example, some states, including Massachusetts, have specific quantitative requirements for solar generation.

Renewable energy credit (REC) prices ranged between essentially zero and 6¢/kWh in recent years, while solar REC prices have been as high as 65¢/kWh.

A common design feature of current state programs, which has been implemented in Massachusetts and (with restrictions) in California, involves tradable renewable energy credits (RECs). Whenever a certified renewable generator produces a MWh of electric energy, the generator also produces a REC. Often the REC is bundled with the electricity and sold under a long-term contract to an LSE. However, many states allow RECs to be sold separately, so that renewable generators are paid both for the RECs they produce as well as for the electricity they generate, which is usually sold on the wholesale market. The LSE then meets its

obligation by turning over the required number of RECs to the agency administering the program. The value of the REC is thus an additional per-MWh subsidy to renewable generators — one that is paid by consumers of electricity rather than by taxpayers (as is the case with the ITC and accelerated depreciation). When there is a specific requirement for solar generation, the corresponding RECs are called solar RECs (SRECs). SRECs are typically more valuable (and hence more expensive for LSEs to purchase) than RECs produced by other renewable generation technologies.

In part because most RECs and SRECs are currently being sold under long-term contracts, REC and SREC markets are thin and data on prices are scarce. We do know that state-level RPS policies vary enormously in stringency and on other dimensions, and the available price data mirror this variation. In addition, REC and SREC prices vary substantially over time: they tend to be close to zero when the corresponding regulatory constraint is not binding and can be very high when there is simply not enough renewable capacity available to meet state requirements. A recent NREL survey (2014) provides some data on REC and SREC prices, showing that REC prices ranged between essentially zero and 6¢/kWh in recent years, while SREC prices have been as high as 65¢/kWh.³⁵ SRECs in Massachusetts seem to have traded for around 20¢/kWh — a very substantial subsidy indeed relative to the cost numbers in Table 5.1. Thus RPS programs, like other state and local policies, may provide very large subsidies to solar generation depending on their stringency. Less stringent policies that impose only weak constraints on LSEs will provide very modest subsidies.

^{xvii}For a detailed discussion of these programs see Chapter 9 of this report and Schmalensee.³⁴

While the total per-kWh value of federal, state, and local subsidies to solar generation in different localities has not been tallied to date, the subsidies that are already in place as a result of current policies and programs have clearly been sufficient to fuel rapid growth in PV investments. Between the first half of 2012 and the first half of 2014, installed residential PV capacity in the United States more than doubled and utility-scale PV capacity quadrupled.

FINDING

Federal-level subsidies in the United States, assuming the current solar investment tax credit (ITC) is 50% effective, reduce the cost of the PV projects studied here by around 20% and the CSP projects by around 13%. These subsidies, in combination with the variety of state and local subsidies provided in California, Massachusetts, and many other states, have been sufficient to fuel rapid growth in PV generation, even though PV technology is notably more expensive than fossil alternatives.

5.6 CONCLUSIONS AND FINDINGS

Several of the results discussed in this chapter and summarized in Table 5.1 deserve emphasis. First, location matters. Because of differences in insolation, it is much cheaper to generate electricity using solar power in southern California than in central Massachusetts.

Second, as directly implied by the investment cost estimates in Chapter 4, the cost of electricity from utility-scale PV is much lower — by almost half — than the cost of residential-scale PV. Third, because CSP plants can only utilize direct sunlight, CSP-generated electricity is much more expensive in cloudy Massachusetts than in sunny California — 135% more expensive. Fourth, as we discuss in general terms in Chapter 3, it may be optimal to add no energy storage, a little energy storage, or a lot of storage to a CSP plant depending on insolation and electricity price patterns. We find that adding energy storage is less beneficial in central Massachusetts than in California mainly due to the former location's lower insolation.

Because electricity demand and thus wholesale electricity prices are usually higher than average during those times of the day and year when the sun is shining compared to those times when it is not, the average kWh of electricity produced from these hypothetical facilities (assuming these facilities had no effect on price patterns at their locations) would be worth, on average, 10% more than the average kWh of electricity produced from a pure baseload facility that had the same output in every hour of the year. Not only is this premium smaller than one might have expected, it was computed using current prices, which reflect systems with very low solar penetration. As discussed in greater detail in Chapter 8, the solar premium will decline as solar penetration rises substantially above current levels, and solar electricity may even become less valuable than average.

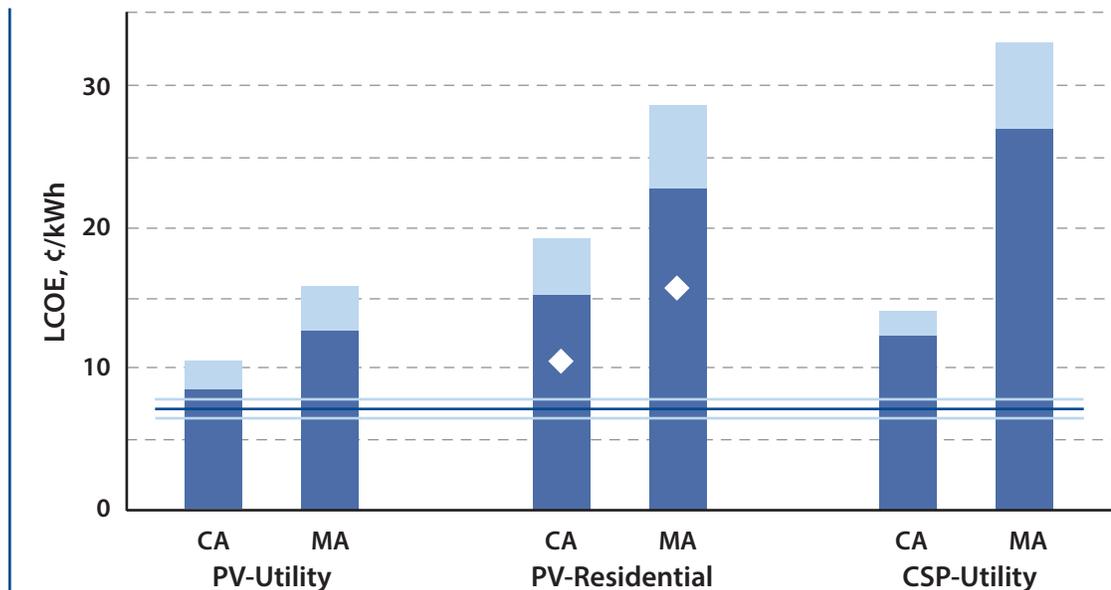
Reflecting the importance of BOS costs for PV installations, we find that reducing the cost of modules by half only reduces estimated costs by about 15% for the utility-scale projects we analyze, and 9% for the residential-scale projects. Recognizing that the residential PV market is immature (see Chapter 4), we present estimates of levelized cost under plausible values for system components in a mature market. This lowers our estimates of levelized cost by around a third. Still, in both the locations we studied, the cost of residential-scale PV remains well above the cost of utility-scale PV.

FINDING

Plausible reductions in the cost of crystalline silicon PV modules alone would be insufficient to make utility-scale PV systems competitive on a subsidy-free basis in the absence of a significant price on carbon. Improvements that reduce residential balance-of-system costs, whether by reducing materials use or reducing installation costs, could make a large contribution.

Reducing the cost of modules by half only reduces estimated costs by about 15% for the utility-scale projects we analyze, and 9% for the residential-scale projects.

Figure 5.3 Summary of Levelized Cost of Electricity Results



Note: The light blue bars show the LCOEs without subsidies as reported in this chapter. All LCOE figures are unadjusted, not reflecting any differential value for the time profile of power produced. The dark blue bar show the LCOEs reduced by the federal tax subsidy at 50% effectiveness as reported in this chapter. For the residential PV, the white diamonds show estimates after a reduction in BOS costs that brings U.S. costs in line with German costs. The dark solid line running across the figure shows a central estimate for the LCOE of an NGCC plant operated at baseload capacity based on data from the EIA as discussed in the chapter. It is inclusive of a carbon charge of \$38/ton CO₂. The light blue solid lines show a range for the LCOE of the natural gas plant reflecting different regional costs as reported by the EIA.

Table 5.1 The Levelized Cost of Electricity for Three Hypothetical Solar Installations in Two Different Locations under Alternative Assumptions

	Utility-Scale PV		Residential PV		Utility-Scale CSP	
	s. CA	c. MA	s. CA	c. MA	s. CA	c. MA
Base Case, ¢/kWh	10.5	15.8	19.2	28.7	14.1	33.1
Value Adjusted	9.3	14.4	17.0	26.2	12.6	29.5
Change from Base Case, ¢/kWh	-1.2	-1.4	-2.2	-2.5	-1.5	-3.6
Change from Base Case, %	-12%	-9%	-12%	-9%	-11%	-11%
50% Module Cost	8.9	13.4	17.5	26.2		
Change from Base Case, ¢/kWh	-1.6	-2.4	-1.7	-2.6		
Change from Base Case, %	-15%	-15%	-9%	-9%		
Reductions in BOS Cost			12.0	18.0		
Change from Base Case, ¢/kWh			-7.2	-10.8		
Change from Base Case, %			-37%	-37%		
With Federal Tax Subsidies, 50% ITC Effectiveness	8.4	12.7	15.2	22.8	12.2	28.5
Change from Base Case, ¢/kWh	-2.1	-3.1	-4.0	-6.0	-1.9	-4.7
Change from Base Case, %	-20%	-20%	-21%	-21%	-13%	-14%
With Federal Tax Subsidies, 100% ITC Effectiveness	6.8	10.1	12.0	18.0	10.2	23.9
Change from Base Case, ¢/kWh	-3.8	-5.6	-7.2	-10.8	-3.9	-9.2
Change from Base Case, %	-36%	-36%	-38%	-37%	-27%	-28%

Finally, we analyzed the effects of the main federal subsidies for solar generation in the United States. Assuming that most solar developers capture only 50% of the value of current federal tax subsidies, these subsidies reduced the levelized cost of solar electricity by 13%–21%, depending on the technology. A detailed effort to measure the subsidy effects

of renewable portfolio standards in California or Massachusetts, let alone the effects of various other state- and local-level support policies in these states and many others, was beyond the scope of our analysis. It is worth noting, however, that all of these subsidies have had and are having a dramatic impact on solar costs in at least some areas.

REFERENCES

- ¹Interagency Working Group on Social Cost of Carbon. *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866*. (May 2013). http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf
- ²*Historical Pricing Data Login*. GDF SUEZ Energy Resources NA, Inc. <http://www.gdfsuezenergyresources.com/historical-data>
- ³*NREL System Advisor Model (SAM): Levelized Cost of Energy (LCOE)* National Renewable Energy Laboratory. https://www.nrel.gov/analysis/sam/help/html-php/index.html?mtf_lcoe.htm
- ⁴Short, W., D. J. Packey, and T. Holt. *Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies*. National Renewable Energy Laboratory. NREL/TP-462-517. (Mar 1995). <http://www.nrel.gov/docs/legosti/old/5173.pdf>
- ⁵Brealey, R., S. Myers and F. Allen. *Principles of Corporate Finance, 11th Edition*, McGraw Hill. Chapter 19 (2013). ISBN-13: 9780078034763.
- ⁶Namovicz, C. “Assessing the Economic Value of New Utility-Scale Generation Projects.” *Workshop on Assessing the Economic Value of New Utility-Scale Renewable Generation Projects Using Levelized Cost of Electricity and Levelized Avoided Cost of Electricity*. U.S. Energy Information Agency. (Jul 25, 2013). http://www.eia.gov/renewable/workshop/genccosts/pdf/1_Namovicz.pdf
- ⁷“Discussion Paper: Assessing the Economic Value of New Utility-Scale Electricity Generation Projects.” *Workshop on Assessing the Economic Value of New Utility-Scale Renewable Generation Projects Using Levelized Cost of Electricity and Levelized Avoided Cost of Electricity*. U.S. Energy Information Agency. (Jul 25, 2013). http://www.eia.gov/renewable/workshop/genccosts/pdf/lace-lcoe_070213.pdf
- ⁸“Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement.” *Workshop on Assessing the Economic Value of New Utility-Scale Renewable Generation Projects Using Levelized Cost of Electricity and Levelized Avoided Cost of Electricity*. U.S. Energy Information Agency. (Jul 25, 2013). http://www.eia.gov/renewable/workshop/genccosts/pdf/methodology_supplement.pdf
- ⁹Norris, B.L., M.C. Putnam and T.E. Hoff. *Minnesota Value of Solar: Methodology*. Minnesota Department of Commerce, Division of Energy Resources. (Apr 1, 2014). <http://mn.gov/commerce/energy/images/MN-VOS-Methodology-FINAL.pdf>
- ¹⁰Frank, C.R. *The Net Benefits of Low and No-Carbon Electricity Technologies*. Brookings Institution, Global Economy & Development Working Paper 73. (May 2014). <http://www.brookings.edu/~media/research/files/papers/2014/05/19%20low%20carbon%20future%20wind%20solar%20power%20frank/net%20benefits%20final.pdf>
- ¹¹Lovins, A.B. “Sowing Confusion About Renewable Energy.” *Forbes*. (Aug 5, 2014). <http://www.forbes.com/sites/amorylovins/2014/08/05/sowing-confusion-about-renewable-energy/>
- ¹²Hirth, L. “The Market Value of Variable Renewables: The Effect of Solar Wind Power Variability on Their Relative Price.” *Energy Economics* 38 (2013): 218-236. <http://www.sciencedirect.com/science/article/pii/S0140988313000285>
- ¹³Schmalensee, R. “The Performance of U.S. Wind and Solar Generating Plants.” *The Energy Journal*, Forthcoming (2014). http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2334946
- ¹⁴Schmalensee, R. *The Performance of U.S. Wind and Solar Generating Plants*. MIT Center for Energy and Environmental Policy Research, Working Paper 2013-12. (2013). <http://web.mit.edu/ceepr/www/publications/workingpapers/2013-012.pdf>
- ¹⁵*PVWatts® Calculator*. National Renewable Energy Laboratory. (Sep 2014). <http://pvwatts.nrel.gov/>
- ¹⁶*Distributed Generation Energy Technology Operations and Maintenance Costs*. National Renewable Energy Laboratory. http://www.nrel.gov/analysis/tech_cost_om_dg.html
- ¹⁷Gowrisankaran, G., S. S. Reynolds, and M. Samano. *Intermittency and the Value of Renewable Energy*. No. w17086. National Bureau of Economic Research. (2011). <http://www.nber.org/papers/w17086.pdf>
- ¹⁸*Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013*. U.S. Energy Information Administration. (Jan 2013). http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf
- ¹⁹*Transparent Cost Database*. OpenEI. <http://en.openei.org/apps/TCDB/>

- ²⁰*Assumptions of the Annual Energy Outlook, 2014*. U.S. Energy Information Administration. (Jun 2014). Tables 1.2 and 8.2. <http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554%282014%29.pdf>
- ²¹*Schedule D: Domestic Service*. Southern California Edison. <https://www.sce.com/NR/sc3/tm2/pdf/ce12-12.pdf>
- ²²*Schedule DR - Residential Service (2/1/14-Current)*. San Diego Gas & Electric. https://www.sdge.com/sites/default/files/regulatory/020114-schedule_dr.pdf
- ²³*Electric Rates: Residential*. Pacific Gas & Electric. <http://www.pge.com/tariffs/electric.shtml>
- ²⁴*Schedule R: Residential Service*. Hawaiian Electric Company. <http://www.hawaiianelectric.com/vcmcontent/FileScan/PDF/EnergyServices/Tariffs/HECO/HECORatesSchR.pdf>
- ²⁵Kassakian, J. G., and R. Schmalensee. *The Future of the Electric Grid: An Interdisciplinary MIT Study*. Massachusetts Institute of Technology. (2011). 182. http://mitei.mit.edu/system/files/Electric_Grid_Full_Report.pdf
- ²⁶*NREL System Advisor Model (SAM): Welcome to SAM*. <https://sam.nrel.gov/>
- ²⁷Turchi, C.S., and G. A. Heath. *Molten Salt Power Tower Cost Model for the System Advisor Model*. National Renewable Energy Laboratory. NREL/TP-5500-57625. (Feb 2014). <http://www.nrel.gov/docs/fy13osti/57625.pdf>
- ²⁸Turchi, C.S., and G. A. Heath. *Molten Salt Power Tower Cost Model for the System Advisor Model*. National Renewable Energy Laboratory. NREL/TP-5500-57625. (Feb 2014): Appendix D – WorleyParsons Subcontract Report: Power Tower Plant Cost and Material Input to Life Cycle Assessment (LCA). NREL-8-ME-REP-0002 Rev2. <http://www.nrel.gov/docs/fy13osti/57625.pdf>
- ²⁹*Plant Cost Index*. Chemical Engineering. <http://www.chemengonline.com/pci-home>
- ³⁰*DSIRE: Database of State Incentives for Renewables & Efficiency*. North Carolina State University. <http://www.dsireusa.org/>
- ³¹Mackler, S. and N. Gorence. *Reassessing Renewable Energy Subsidies: Issue Brief*. Bipartisan Policy Center. (Mar 25, 2011). http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/BPC_RE%20Issue%20Brief_3-22.pdf
- ³²Pololefsky, M. *Tax Evasion and Subsidy Pass-Through under the Solar Investment Tax Credit*. Working Paper 13-05, Department of Economics, University of Colorado at Boulder. (Nov 2013). http://rintintin.colorado.edu/~sandt/ThirdpartyPV_paper_14.pdf
- ³³*Wholesale Electricity and Natural Gas Market Data*. U.S. Energy Information Administration. (Feb 5, 2015). <http://www.eia.gov/electricity/wholesale/>
- ³⁴Schmalensee, R. “Evaluating Policies to Increase Electricity Generation from Renewable Energy.” *Review of Environmental Economics and Policy* 6, No. 1 (2012). 45–64. <http://reep.oxfordjournals.org/content/6/1/45.full.pdf+html>
- ³⁵Heeter, J., G. Barbose, L. Bird, et al. “A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards.” National Renewable Energy Laboratory. NREL/TP-6A20-61042. (May 2014). <http://www.res4med.org/uploads/studies/1402067633NREL.pdf>
- ³⁶*New Report Shows U.S. Solar Industry Nearing 16 GW of Installed Capacity*. Solar Energy Industry Association. (Sep 4, 2014). <http://www.seia.org/news/new-report-shows-us-solar-industry-nearing-16-gw-installed-capacity>

The hyperlinks in this document were active as of April 2015.