A Review of Cost Comparisons and Policies in Utility-Scale and Rooftop Solar Photovoltaic Projects

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Executive Summary

Solar photovoltaic (PV) systems are a fast-growing source of new electric power in the U.S. Systems are being installed rapidly, at every scale, from the smallest residential rooftop systems of just a few kilowatts to commercial and community scale systems ranging up to as much as several megawatts, and all the way up to utility systems ranging to more than 100 MW. Researchers investigating the levelized cost of energy (LCOE) from solar PV generally find that larger systems cost less per unit of capacity and energy delivered. The best available data generally show that the smallest systems tend to cost roughly twice as much per kilowatt, or even more, compared to the largest systems, and that cost differences by system size have been persistent over time.

Reported cost differences are primarily the result of economies of scale in engineering design and construction, and discounts through the bulk purchasing of components. Existing studies vary in several important ways, most notably:

(1) Varying assumptions for important inputs;

(2) Representing different time periods, which is important because PV costs have fallen rapidly, across the board, in recent years; and,

(3) Reflecting costs and solar production in different locations and utility territories, where PV markets are more or less active and mature and the available solar resource varies by as much as 50%.

Regardless of these kinds of differences, though, PV cost studies generally find that utility-scale systems might cost roughly half as much, or even less, compared to much smaller rooftop systems.

This report reviews and compares solar PV LCOE studies and forecasts of how current cost trends might affect PV economies of scale in the coming years. It also briefly explores how ratepayer- and taxpayer-funded incentive policies sometimes distort PV system economics by favoring only certain system types and sizes.

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I. Introduction

A. Purpose

The purpose of this study is to objectively analyze reports about the costs of utility-scale and rooftop solar photovoltaic (PV) installations so that regulators, legislators, and other stakeholders can better understand why PV costs tend to be lower for larger scale systems. The project specifically examines and reports on differences in levelized cost of energy (LCOE) between small-scale rooftop and large-scale utility PV projects. A basic definition of LCOE is:

> [T]he constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors. Levelized [cost of electricity] is comprised of three components: capital charge, operation and maintenance costs, and fuel costs. (MIT 2007, p. 127).

LCOE is an objective tool for analyzing cost, and comparative cost is one critical element for utilities, utility consumers, and regulators, for determining what technologies utilities could or should build or purchase. LCOE studies reflect a bottom-up analysis, where costs are determined based on a set of assumptions. Ideally, each assumption will accurately reflect the best available real-world data. LCOE studies typically include the sum of fixed costs, variable costs (such as operations and maintenance, and fuel for fuel-using systems), and financing costs, such as the cost of debt and equity capital (Branker et al., 2011; EIA, 2013a; Namovicz, 2013).

This paper summarizes general findings from existing PV cost studies, identifies the major factors that influence PV project costs, discusses the inherent challenges in directly comparing the findings from different PV cost studies, and reports on caveats and challenges to using LCOE as the sole measure for determining cost-effectiveness.

Conducting this study is important and timely for two major reasons. The primary reason is that PV installations are increasing rapidly. PV system costs are declining, and cost reductions are generally associated with rapid growth in the numbers and cumulative capacity of all sizes of PV installations (Fox, Stanfield, et al., 2012, pp. 7-8; Wesoff, 2013). According to EIA (2013b), rooftop solar electricity currently accounts for less than one-quarter of 1 percent (0.25%) of the nation's power generation. But, since 2010 rooftop solar has been increasing at an average annual rate of about 50% per year. Also, utility-scale PV in the US was practically non-existent until about five years ago, but its capacity is now growing rapidly. Nearly 1 GW of utility-scale PV was installed in the US in 2011, that amount roughly doubled in 2012, and is expected to double again by 2014 and redouble by 2016 (Shayle et al., 2013).

Second, given current product costs, market conditions, and existing policies, PV is fully economical in some locations and applications (Branker et al., 2011; LaMonica, 2013; Lawrence, 2013; Stanton, 2013, p. iv). But currently, PV is competitive in many applications in part because of substantial benefits conferred by a variety of favorable policies, sometimes subsidies, which frequently include supportive utility tariffs; special federal, state, and local tax treatment; and financial incentives supported by utility ratepayers, taxpayers, or both. Part IV of this paper reviews how existing policies sometimes favor some system types and sizes and not others, thus distorting markets in ways that might be unintended and could have negative consequences.

B. Overview of PV cost studies

PV cost studies are used for three different major purposes: technology comparisons, investment analyses, and identifying opportunities for future cost reductions. All three share some of the same challenges because (a) many of the relevant cost factors are rapidly changing; (b) system equipment is not yet standardized at any of the relevant scales and costs vary widely because of individual system design and locational characteristics, plus differences in the maturity of solar markets in different places; and (c) there are relatively few large commercial and utility-scale installations to analyze, and accurate, disaggregated cost data for individual system components can be obtained for only a subset of those installations. In addition, studies for each of the three purposes present different challenges and potential pitfalls.

First, studies are used to compare the costs of generating electricity using solar PV as compared to other renewable and fossil-fueled technologies and to compare different PV system types to one another. Perceptions of the cost of solar energy depend primarily on how the cost of installing and operating a solar system compares to other generation technologies, such as wind, natural gas, and coal. A primary goal of these studies is to compare PV to other technology options (e.g., coal, gas, nuclear, and other renewable-powered generating systems), to investigate whether and how PV systems could compete. The primary uses for these comparisons are in utility resource planning and to aid in policy formulation. The standard that is typically discussed is called grid parity, which means that the cost of solar energy is equal to the cost of the traditional power supply options that the solar can displace.

Second, PV system developers and potential customers use cost studies to understand production costs and compare them to wholesale or retail utility rates, to investigate business models and specific investment opportunities. These studies often focus on what is called "socket parity," meaning the comparison of solar PV costs to a consumer's retail price of energy (Bazilian, Onyeji, et al., 2012).

Thinking about grid parity and socket parity underscores a major difference between rooftop and utility-scale PV: Rooftop systems typically deliver electricity to one or more end-use consumers that is valued at the retail rates that would otherwise apply, but utility-scale systems must compete with other providers at the wholesale level. That difference presents a lower cost hurdle for rooftop systems and a higher one for utility-scale PV, but does not mean that rooftop systems are more economical.

A third major research purpose for PV cost studies is to help identify opportunities for improvements in the solar-production value chain that are most likely in the near future to lead to lower costs and reduced incentives and subsidies. That is the focus of so-called "roadmap" projects, like the U.S. Department of Energy *SunShot Initiative* (DOE, 2012) and IEA (2010) *Technology Roadmap.* Those studies are particularly concerned with opportunities for learning-curve (also sometimes called experience-curve) improvements; studies help identify the best opportunities for future reductions in the costs for various system components, helping to identify the most important opportunities for focusing limited financial incentives and public funds available for research, development, and demonstration projects.

In the remainder of this paper:

- Part II briefly summarizes published literature about PV system costs, reporting on both the methods used and factors analyzed, and identifying the most important factors that explain the cost advantages of larger system sizes.
- Part III considers available future cost projections, exploring how the various components are likely to change over time as the solar industry benefits from learning-curve effects (Hernandez-Moro & Martinez-Duart, 2012, p. 122).
- Part IV reports on the major ways that current policies often favor some system types and sizes, to the detriment or exclusion of others. And, Part IV offers some starting suggestions for thinking about how policies might be altered to remove market distortions while continuing incentives necessary to the growing solar PV industry.
- Part V includes a brief summary of this report and outlines questions for future research.

II. Analyzing PV System Costs

This section reviews recent reports of solar PV system costs. The primary purpose is to compare the reports, to explore how much concurrence there is regarding PV system costs and the extent to which the costs vary by system size.

PV system costs are usually analyzed in one of two ways. One reviews reported data from actual installed systems in order to understand prices and how those relate to costs, and the other uses LCOE analyses, which is the major focus of this study. The first type of study relies on publicly available data on installed system costs, and basically assumes that the systems are built only when and if they meet the needs of customers and developers. These studies are useful in observing system cost changes over time; however, they reflect specific local conditions and existing financial incentives and rate structures, without necessarily clarifying the roles played by such local conditions.

A. General findings from existing PV cost studies

Analysts comparing PV system costs usually differentiate solar systems by size, often dividing into only two broad categories: rooftop versus utility-scale systems. Rooftop systems are sometimes further divided into residential scale and commercial scale. Though there is no standard agreement on what constitutes a prototype PV system at each scale, classifications typically focus on residential systems from 2 to 10kW, commercial systems in a broad range from 10kW to as much as a thousand kW or more, and utility scale from a few MW to tens or even hundreds of MW. Residential systems are variously installed on rooftops or in side or back yards. Most commercial systems are installed on flat or low-sloped roofs, but some are also ground mounted. Utility-scale systems are most often ground-mounted, but smaller utility-scale systems are also sometimes installed on large flat roofs.

In all categories, average system costs have been decreasing in recent years, in concert with declines in the costs of solar modules and balance-of-system (BOS) components. At the same time, the capacity of PV systems has increased across the board, for residential, commercial, and utility-scale, in concert with those declining costs. And, the ratio of PV module capacity is frequently increased compared to inverter capacity, so that the whole system capacity factor increases (Chen et al., 2013).

Table 1 lists the major components included in the different system sizes and the expected percentage of costs each component represents for each system size. As Table 1 shows, the major differences between the system sizes and types are in labor costs, installer overhead and profit, supply-chain costs, and land acquisition and site preparation that apply only to utility-scale, ground mounted systems.

Table 1: Major component costs of utility-scale and rooftop solar PV

Components	Utility-Scale Fixed Ground Mount	Utility-Scale 1-Axis Tracking[1] Ground Mount	Commercial Rooftop	Residential Rooftop
Solar PV modules	51%	44%	45%	38%
Inverter	8%	7%	8%	7%
Installation materials	10%	10%	14%	8%
Electrical labor	9%	11%	6%	5%
Hardware labor	2%	2%	<1%	6%
Permitting and commissioning	<1%	<1%	4%	3%
Installer overhead	2%	3%	2%	6%
Installer profit	1%	2%	2%	5%
Supply chain costs[2]	7%	7%	14%	17%
Sales tax	6%	6%	6%	5%
Land acquisition	<1%	1%		
Site preparation	3%	5%		
Tracking system hardware		3%		
Total estimated installed cost in second half 2010	\$3.80/Wp-dc[3]	\$4.40/Wp-dc	\$4.59/Wp-dc	\$5.71/Wp-dc

Source: Goodrich, James, and Woodhouse, 2012. Percentages reflect the approximate portion of total cost attributable to each component type, and may not add to 100% due to rounding errors.

Notes:

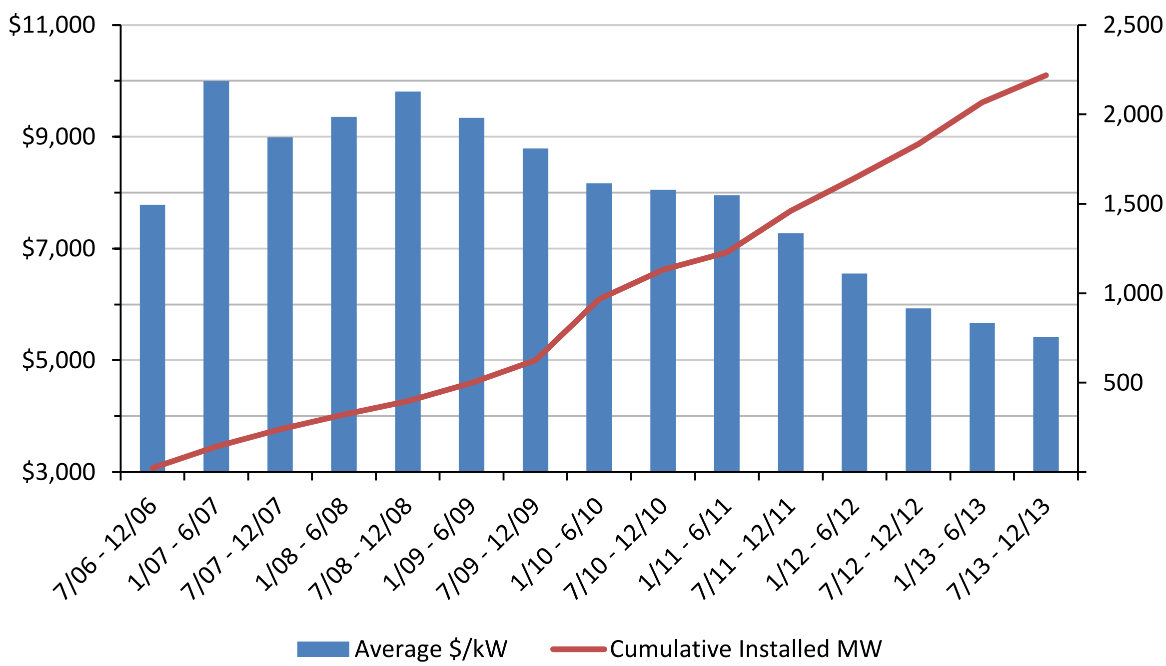
1 "Tracking" refers to PV mounting systems that are adjustable, so that the panels can be moved to face more directly towards the sun as its angle of incidence changes, daily and seasonally. See DOE, 2012, p. 291.

2 Supply-chain costs refer to the physical supply of all inputs involved in a product's development, deployment, and operation, including, for example, the logistics associated with transportation, warehousing, and delivery of the various raw materials, components, and finished products.

3 "Wp-dc" is a measure of the generating capacity of a PV system, measured in peak Watts of DC power.

Figures 1 and 2 show overall trends in solar PV system costs in the past several years. The data are from the California Solar Initiative database, based on the installed costs reported in the application process for customers receiving financial incentives.[1] Figure 1 shows the average system cost for the whole database and Figure 2 breaks down the same data set by system size, reflecting small, residential scale systems (up to 5 kW, n = over 90,500 systems), small commercial (over 5 to 50 kW, n = over 66,000), medium-sized commercial (more than 50 up to 500 kW, n = over 3,750), and large commercial (over 500 kW up to more than 5 MW, n = 770). These data do not include utility-scale PV systems. Figure 2 shows the general, persistent trend: Larger systems are less expensive per unit of capacity and energy produced.[2]

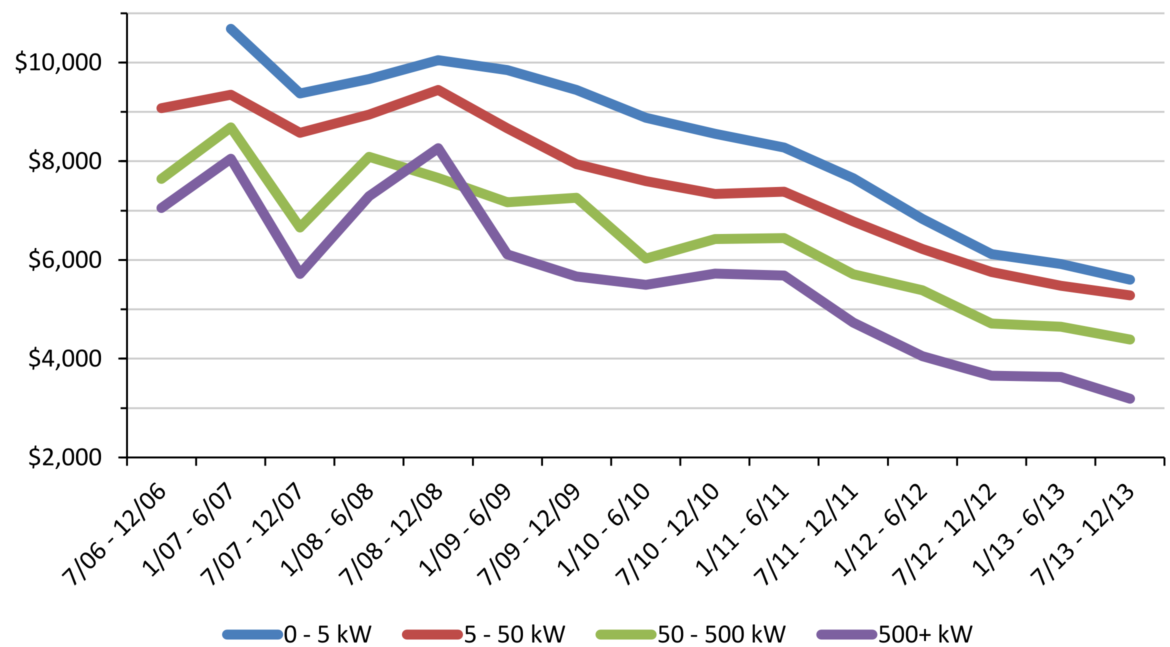
Figure 1: Average PV system installed cost ($/kW) and cumulative capacity (MW) reported in California Solar Initiative database



[1] California is home to a large share of all US PV installations. California installations as a percent of the U.S. total have been declining in recent years, but still ranged from around 70% of all US installations in 2007-08 to about 40% of all installations in 2013 (Feldman et al., 2013; Kann et al., 2013).

[2] In Figure 2, temporary cost increases from 2007-2008 are reportedly due to programmatic changes and the one-time reversal in costs reported for the two largest system types results in part from a very small number of systems installed in the second half of 2008 (personal communications, 29 Apr 2014, James Leowen, California Public Utilities Commission).

Figure 2: Average system cost per kW based on system size reported in California Solar Initiative database



As shown in Tables 2 and 3, comparing LCOE studies to one another proves challenging because of the substantial variation in input assumptions and data sources. With the relatively small number of studies and wide variability in input assumptions, it becomes practically impossible to make simple comparisons among the reported LCOEs. Primary differences in published PV cost studies are summarized in Table 2 and findings from some recently published PV cost studies are included in Table 3. As shown in Table 3, the studies present findings in different terms, which adds to the difficulty in comparing studies to one another.

For example, one report (Branker et al., 2012) reviews over two-dozen PV LCOE studies, completed between 2003 and 2011. Eighteen of those studies report on utility-scale systems (3.5–80MW) and a similar number report on residential scale systems (generally 2–5kW). Only a half-dozen of the reviewed studies explicitly present LCOEs for commercial scale systems (on the order of 150–500kW). Reported LCOEs in these studies range from 15 to 86 cents per kWh for residential scale, to 10 to 40 cents for commercial, and 12 to 80 cents for utility-scale. These wide ranges in calculated LCOE costs demonstrate the important effects of differences in major assumptions.

Table 2: Major Differences Observed in PV LCOE Study Inputs and Assumptions

Input or Assumption	**Importance in Determining LCOE and Variability Observed in LCOE Studies**
Vintage of equipment costs	Costs have been declining rapidly in recent years. Studies reflect costs from 2003 to 2015. During that time, system costs have declined by as much as 80%.
Expected lifetime of modules and of major system components	Expected lifetime varies from 20 to 40 years. Some studies assume that power inverters are replaced after 10 or 15 years, increasing system costs.
System degradation rates	Production typically degrades slowly as modules age. Degradation rates reported are from zero to 2% per year.
Average weighted cost of capital (AWCC) or discount rate	Assumed rates from 5% to 15%. Some studies use nominal dollars and others real dollars.
Location modeled	Solar radiation and thus expected average annual capacity factors vary. Capacity factors modeled are typically in the range of 15% to 30%.
System types to model	Examples include thin-film or crystalline modules, and fixed versus 1-axis or 2-axis tracking system mounting. Capacity factors thus differ by a few percentage points.
Whether and how to include interconnection and system operations costs	Examples include estimated adders or actual costs for transmission and interconnection and costs associated with firming up variable output generation.
Whether or not to include available subsidies, tax benefits, and special financial incentives	Total available subsidies and incentives sometimes reduce apparent total system cost by as much as 70%.

The broad picture from PV cost studies is that economies of scale do exist, but can eventually be exhausted, and even reversed, because of system- and location-specific factors. This general trend, illustrated in Figure 3, is that average PV system costs per unit of capacity decrease as system size increases. To put these illustrative cost data in perspective, the smallest residential rooftop systems might produce energy at an average cost of roughly 50-cents/kWh, while large utility-scale systems might average close to 10-cents/kWh. Costs decrease rapidly at first, in the smallest residential system sizes, and then the rate of decrease slows as the system size grows to larger and larger commercial systems and on into utility-scale systems.

Table 3: Major Criteria Included and Values Reported in Selected Published Solar PV Cost Analyses

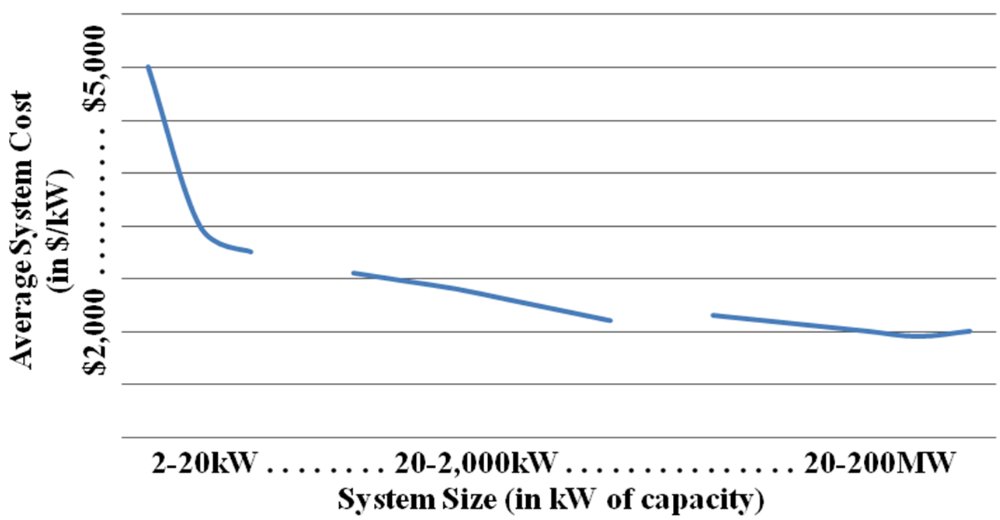
Criterion→ ↓ Study↓	Location Modeled	LCOE Calculated ($/MWh)	System Size Modeled	Overnight Capital ($/MW)	Fixed O&M	Discount Rate (%)	Assumed Average Annual Capacity Factor
Branker, Pathak, and Pearce (2011, reflecting 2008 system costs).							
Utility-Scale	Ontario	$144	150MW		$9.9/MWh	6.6%	25%
Rooftop	Ontario	$225		$5,000		4.5%	14.5%
Feldman et al., NREL and LBNL (2013, reflecting expected 2013 system costs)							
Utility-Scale	US, reported averages		190MW	$1,920			
Rooftop	US, reported averages		5kW, 220kW	$2,610–$3,690			
Goodrich, James, and Woodhouse, NREL (2012, reporting 2010 system costs)							
Utility-Scale	US, reported averages		187.5MW	$4,590–$5,710			
Rooftop	US, reported averages		~5kW, ~200kW	$3,800–$4,400			
Lazard, version 7.0 (2013, reporting estimated 2015 levelized costs for utility-scale systems)							
Utility-Scale	US Southwest	$51–$104	10MW	$2,750–$3,500	$7–$8/MWh	9.6%	20%–27%
Rooftop	US Southwest	$117–$204	10MW	$3,750–$4,500	$6–$11/MWh		20%–23%
Sinha et al. (2013)							
Utility-Scale		$72–$144					
Rooftop		$77–$231					

Notes: Goodrich, James, and Woodhouse (2012) report costs prior to subsidies.

Lazard presents costs for systems with and without the 30% federal investment tax credit.

The Feldman et al., NREL and LBNL study relies on data reported from "approximately 65% of all grid-connected PV capacity installed in the U.S. through 2012 and about 50% of all 2012 capacity additions" (p. 7), plus sample reports from approximately 70% of all U.S. utility-scale (>2MW) projects, "regardless whether electricity is delivered to utility or customer" (p. 13).

Figure 3: General cost trends reported in PV cost studies.



Source: Author's construct based on general observations from all reviewed studies, adapted from Goodrich, James and Woodhouse, 2012, Figure 4.

Feldman et al. (2013, p. 19) report average cost reductions of 22% to 26% as systems increase in size from 5MW to 185MW, with almost three fourths of that cost reduction evident as system size increases from 5MW to 20MW. However, Feldman et al. also explain that at some point, in the largest utility-scale systems, economies of scale could be exhausted, in which case total costs would tend to increase again, though they would still remain well below the cost of much smaller systems (as illustrated in Figure 3). Howland (2014) reports:

> Huge projects may benefit from economies of scale, but they face tough permitting requirements and need large high-voltage power lines to deliver their power. In contrast, smaller-scale projects in the 20 MW range and rooftop solar are much easier to develop, can be more easily sited and can be located closer to where they are needed.

Bolinger and Weaver (2013) and Feldman et al. (2013) report the strongest economy-of-scale effects at the smallest system sizes, in the range of 2kW or smaller to the 5–10kW range. Lazard (2013) agrees that the capital cost per kW for rooftop systems is much higher than for utility scale: Lazard estimates almost twice as much. Feldman et al. (2013, p. 10) state:

> Installed prices exhibit clear economies of scale, with the median installed price for the largest commercial systems 38% lower than for the smallest residential systems. … Scale economies are especially pronounced at the small end of the size spectrum. Substantial variability in installed prices

> exists within each size range, reflecting regional, local, project/site-specific, and installer-specific drivers.

Feldman et al. (2013) explain that utility-scale systems also often have lower hardware cost per unit of capacity, since rooftop systems require more customized work compared to utility systems. Feldman et al. note that utility systems are usually ground mounted and can use more standardized mounting and installations. These researchers also report that utility-scale projects tend to perform somewhat better (e.g., have higher capacity factors), because rooftop systems are often partly shaded or are otherwise constrained by roof configurations that are at sub-optimal tilt angles. Utility-scale projects are less constrained by existing site conditions, are seldom shaded, and often employ 1- or 2-axis tracking systems.[3] Those factors help utility-scale PV to increase energy production, compared to rooftop systems in the same geographic area.

Focusing on utility-scale systems, up to as much as 100MW or more, Goodrich, James, and Woodhouse (2012, p. 12) conclude:

> [E]conomy-of-scale benefits are clear, because the fixed costs for ground-mount systems—including permitting and regulatory costs, project transaction costs, and engineering design—are amortized over a greater system size. The scale of utility PV systems is also a significant factor that differentiates this sector from the residential rooftop market, because system size affects not only the configuration of system components, but also their installation methods, channels to market, and resulting system cost structure.

Borenstein (2012) confirms, "Small scale rooftop solar, such as on a single-family home, also enjoys fewer economies of scale in construction or panel procurement, so the up-front cost per unit of capacity tends to be much greater." Barbose (2012) also reports that commercial-scale rooftop systems, on the order of 1MW and larger, cost an average of 42 percent less than residential rooftop systems, and utility-scale systems cost even less per kW and kWh. Goodrich James, and Woodhouse (2012, p. 13) report that (a) residential system costs decline by approximately two-thirds as sizes increase from about 2 to 15kW; (b) commercial system costs are much steadier, but still decline by a few percentage points as sizes increase from about 10kW to as much as 1MW; and (c) utility-scale system costs per MW and MWh decline by over half as sizes increase from about 1MW to as much as 100MW.

Bolinger and Weaver (2012, p. 6) also find that utility-scale PV projects exhibit economies of scale, however, they note that the impact is most pronounced at the very low end of the utility-scale size range. They explain, as depicted in Figure 3, that scale economies appear to diminish considerably for systems larger than about five to ten MW. Bolinger and Weaver (2012, p. 22) point out:

> [V]ery large projects often face greater development challenges than smaller projects, including greater environmental sensitivities and more-stringent permitting requirements, as well as more interconnection and transmission

[3] "Tracking" refers to PV mounting systems that are adjustable, so that the panels can be moved to face more directly towards the sun as its angle of incidence changes, daily and seasonally. See DOE, 2012, p. 291.

> hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from scale economies.

B. Caveats and challenges to PV cost studies

Critics raise two sets of concerns about using LCOE studies to guide utility resource acquisition decisions. A first set is associated with details of LCOE implementation, and a second set is based on the idea that LCOE alone is an incomplete measure.

1. General critiques of LCOE studies

Researchers note that difficulties sometimes occur when LCOE studies: (a) do not disclose all important assumptions; (b) report national metrics, when location has many known important influences on system cost and performance; (c) ignore technology-specific transmission cost, line losses, interconnection costs and utility-system operating costs; (d) exclude risk and financing factors; (e) exclude differing environmental costs among different technologies; and (f) provide a single snapshot of costs, which is effectively the researchers' best guess, instead of reporting a range of costs along with explanations of the sensitivities to variations in input assumptions that might cause the cost variations.

Branker, Pathak, and Pearce (2011) find that LCOE calculations lack clarity in reporting assumptions, and thereby produce widely varying and contradictory results. Problems they cite include using out-of-date data (which overstates current and near future costs because costs are falling), failing to account for the full costs and full lifecycle of power plants, and inconsistently modeling government incentives and related policies. That is, some studies present system costs after subtracting available incentives and subsidies but other studies ignore them.

In addition, Goodrich, James, and Woodhouse (2012, p. 34) report that LCOE studies often neglect sensitivity analysis and thus present a false sense of certainty. Sensitivity analysis can account for uncertainty and test for the robustness of the identified outcome. But, the static nature of most LCOE studies limits their usefulness in analyzing technologies that are subject to dynamic changes, like solar PV at present. For example, Goodrich, James, and Woodhouse (2012, p. 34) explain:

> Because of the rapid U.S. PV system cost reductions resulting from global module price declines, market price data have become insufficient for providing policy makers and industry stakeholders with an accurate and current understanding of system-price drivers. A time-lag effect and the dynamics of a nascent industry disconnect reported system prices from underlying system costs.

Thus, some researchers caution against over-reliance on any one specific finding, because cost studies do not often report sensitivity analyses and sometimes fail to include explicit descriptions of all of the inputs and assumptions used in modeling. Those two pieces are necessary for fully understanding the analyses and comparing studies with one another.

2. Specific critiques based on variations by location

Baker, Fowlie, et al. (2013, p. 4) and Bazilian et al. (2012, p. 332) note important challenges associated with matching PV costs and benefits with specific locations. For example, the average annual capacity factor of installed PV equipment varies by location, in concert with the differences in available solar radiation. In addition, some system sizes in particular locations will require transmission or distribution system upgrades and other grid-related costs. For example, utility-scale solar projects often involve new transmission costs, while small rooftop solar systems generally do not.

The same is sometimes true for integration costs that result because of the inherent variability of solar output, which can lead to mismatches between supply and demand, especially as a result of partly cloudy conditions. That variability can, in turn, cause voltage and frequency to deviate from their optimum levels and thus require additional utility operating expenditures to keep supply and demand in balance (Borenstein, 2011; Joskow, 2011). Such challenges are likely to increase when PV reaches higher levels of production in any specific areas on a utility grid. Still, grid interconnection and integration costs (most notably costs associated with managing the variable-output of solar PV) are seldom included in PV LCOE studies (exceptions include EIA, 2013; Sinha et al., 2013).

Even when such costs are included in PV cost studies, though, an average cost is sometimes used, whereas the actual cost for any specific installation could be quite different.

Many studies also note that substantial variability in installed prices exists within each size range, reflecting specific differences in factors that vary by region and sub-region, project site, equipment employed, and installer (Feldman et al., 2013, p. 10). Bazilian et al. (2012, pp. 330-332) point out that PV cost studies require many assumptions and that reasonably accurate input data is subject to wide variation, based on specific local conditions and “the financial return requirements of investors,” and they raise the additional concern that studies sometimes present outdated costs to policy makers without appropriate caveats. Goodrich, James, and Woodhouse (2012) found that irrespective of system size, “significant variation (standard deviations of 5%–8%) exists…due to regional and site-specific cost factors.” Single-point calculations also fail to capture the variability associated with engineering and construction requirements and differences in local solar radiation.

3. LCOE is an incomplete measure for resource planning

In addition to those concerns, some critics point out that LCOE is an incomplete measure because it focuses exclusively on cost, without measuring or reporting the value of capacity and energy produced (see, for example, EIA, 2013a and 2013b, and Namovicz, 2013). Some critics point out that LCOE alone is not an ideal tool for comparing technologies that have very different operational profiles and system value: Especially important for solar, LCOE does not account for either the time-of-day and seasonal value of the energy produced, nor the differential value of energy depending on where it is delivered (Namovicz, 2013, p. 5).

Techniques proposed for including both costs and benefits into a more comprehensive measure include value-of-solar (VOS), levelized-avoided-cost-of-energy (LACE), and Cost of New Entry (CONE) analyses (VOS and LACE are discussed in Joskow, 2013; Minnesota Public Utilities Commission, 2014; Namovicz, 2013; RMI, 2013, pp. 13-17, 22-23; and Stanton, 2013, pp. 22-24; CONE is discussed in Cutter, Haley, et al., 2014). CONE appraisals attempt to combine cost and value into a single metric. CONE compares “the all-in annualized fixed costs” of a new capacity resource, including return on investment, to the net revenues the resource can earn from its output

Some studies also explore how quantifying and monetizing environmental benefits would elevate solar’s standing, relative to fossil-fuel and other generation technologies (Sinha et al., 2013). Other public benefits some groups attribute to solar electricity generation include job creation, national security, and contributing to the country’s overall growth. Thus, some researchers propose including these kinds of benefits in solar benefit-cost studies. As Borenstein (2011) explains, however, some of these benefits might be dubious in theory and others are difficult to quantify.

This paper does not review or report on analyses of solar PV benefits. Rather, the focus here is on costs and in particular how costs relate to system size. To be fair, it should be noted that LCOE was never intended to answer all of these questions about the value of energy or the benefits it provides. Rather, LCOE is a particular tool for a particular job; comparing various generating technologies to explore their costs.

III. Analyzing Major PV System Cost Components and Trends

A. Overview of PV System Cost Trends

One purpose for analyzing PV system component costs and trends is to explore whether currently evident cost differences between utility-scale and rooftop PV are likely to stay the same or change as PV technologies change and PV manufacturing and supply-chains gain experience. The supply-chain, for any industry, includes the physical supply of all inputs, "from the source of raw materials all the way to equipment end-of-life that [affects] the scale of development, deployment or operation of the technology" (Lehner, Rastogi, et al., 2012, p. 10). This includes, for example, the logistics associated with shipping, transportation, warehousing, and delivery, of the various raw materials, components and finished products (see Jacoby, 2012).

A common belief is that with the additional production, installation, and operation of solar systems, system costs will continue to decline in the future. That is, the past decline in solar costs reflects a learning curve or what analysts call an "experience curve." Such a downward trend in cost can lead to a growth spiral, as increased production lowers the price, which then leads to higher demand and therefore higher production, which repeats the cycle and thus bolsters continuing solar-industry growth.

PV system costs generally reflect three different major cost categories: (1) the PV modules themselves; (2) balance-of-system hardware, including site preparation and mounting systems, power electronics gear including inverters, switches, and wiring; and (3) so-called "soft costs," which include things like marketing, customer acquisition, siting, permitting, applications, regulatory and contractual transactions, insurance, and property taxes. Depending on local factors, there can also be important balance-of-system hardware and soft costs associated with interconnecting a PV system with the electric grid. Here, each of these three categories is discussed in turn, with a focus on economies of scale and the likely persistence of today's economies of scale, given changes expected in the foreseeable future.

B. Review of Cost Trends for Major PV System Components

1. Modules

In a given PV project, the price of a PV module, which is an interconnection of PV cells made of semiconductor material, is a function of the total of manufacturing and delivery costs. Over time, modules have decreased in cost due to combinations of economies of scale in manufacturing, improved module efficiency in converting solar radiation to electricity, and reduced raw-materials costs.

A module's value depends on its performance efficiency in converting solar radiation to useful electricity. The efficiency or performance of solar panels depends on such factors as location, installation angle, and whether the modules are installed in a fixed array or including some means of adjusting the angle to track the path of the sun through the sky.

The historical, gradual improvement in efficiency and reduction in manufacturing cost for solar modules reflects what is known as Swanson's Law. Similar to Moore's Law for computing hardware, Swanson's Law (named after Richard Swanson, the founder of SunPower, a large American solar-cell manufacturer) states that each doubling in cumulative solar PV shipments is associated with a 20 percent reduction in module price (Pethokoukis, 2013). Carr (2012) reports:

> Swanson's Law… suggests that the cost of the photovoltaic cells needed to generate solar power falls by 20 percent with each doubling of global manufacturing capacity.

This trend has generally held since the middle 1970s until the present, with some diversion from the trend in 2005–2007, when solar promotional policies, especially in EU countries such as Germany, Italy, and Spain, created a sellers' market. Since that time, however, increases in global PV manufacturing capability have returned costs to the Swanson trend. Feldman et al. (2013, p. 18) explain that the overnight capital cost of PV systems fell about 15% per year since 2009, with 50% to 75% of the cost reductions attributed to decreasing module prices.

One presumption is that past trends (e.g., Swanson's Law) will hold in the future, but not everyone subscribes to this belief. For example, Feldman et al. (2013, p. 4) state, "[A]nalysts expect system prices to continue to fall, but for module prices to stabilize…by 2014." There is some disagreement among analysts over the relevance of past experience for predicting future solar costs (Borenstein, 2011; Candelise, 2013; de La Tour, 2013; Hernandez-Moro & Martinez-Duart, 2012). Even if an analyst feels confident in estimating historical learning-curve improvements, there is no underlying theory or logic that ensures ongoing future improvements. One criticism is that past trends fail to capture the multiple, complex drivers of cost reductions. Past trends cannot, for example, predict discontinuities in learning due to technological breakthroughs, market structural changes, and possible future barriers to development (Candelise et al., 2013). Another dispute is over the extent to which past learning experiences contributed to the historical continuous decline in the cost of solar projects.

Although PV solar experience curves have been mostly developed for PV module prices, total PV system costs represent an amalgamation of different learning-curves for all components, including balance-of-system hardware and soft costs. Goodrich, James, and Woodhouse (2012) report that module price and performance remain a significant opportunity for future cost reductions. In addition to the expected evolutionary cost reductions for modules, due to improvements in both price and efficiency, Goodrich, James, and Woodhouse suggest that advanced installation methods, such as unitized construction techniques, will also provide considerable installation-labor and materials-related cost benefits by 2020. These researchers believe that as the U.S. market matures, competition among installers and improvement of supply chain and regulatory practices will likely contribute to further cost reductions.

In any case, researchers have noted an association between bulk-purchasing of PV modules and lower prices. Manufacturers and dealers often discount prices for PV modules and other components depending on the size of purchase. That factor leads to economies of scale in construction, which favors the larger commercial and utility-scale system sizes. A plausible counterpoint, though, is that by standardizing small system designs and engaging in aggregated purchasing, dealers and installers can conceivably offer the same or nearly the same module and component prices for large numbers of small systems. Standardizing could affect all major cost components, including modules, balance-of-system hardware, and even to some extent soft costs.

2. Balance-of-system hardware

Balance-of-system (BOS) hardware components include an inverter and any power-conditioning equipment, mounting hardware, switches, and wiring. BOS hardware components tend to make up more than half of total system costs. Goodrich, James, and Woodhouse (2012, p. 1) note, “As module prices continue to fall, the contribution of non-module costs to the cost of solar energy will increase.” The DOE *SunShot Vision Study* (2012, p. 86) explores possibilities in reducing BOS hardware costs by seven measures, including (1) improving supply chains for BOS components; (2) developing high-voltage systems; (3) developing advanced PV racking systems that enhance energy production or require less robust engineering; (4) integrating racking and mounting components in modules; (5) developing innovative materials (e.g., steel or aluminum alloys designed specifically for solar industry applications) for applications such as lightweight, modular mounting frames; (6) creating standard packaged-system designs; and (7) developing building-integrated PV (BIPV) technologies, which can replace traditional roofing and building-facade materials.

Innovations in BOS hardware, such as less expensive mounting systems and micro-inverters, are helping BOS hardware to echo Swanson’s Law for cost reductions. As Goodrich, James, and Woodhouse (2012, p. 6) explain, standardizing systems is “critical to future PV system cost reductions.”

One way that BOS hardware relates to economies of scale is that utility-scale ground mounting can often be less expensive compared to roof mounting. For example, Sinha (2013) reports that utility ground mounting results in about 20% total system cost savings compared to rooftop systems. The savings can result from (1) standardization as opposed to customization, (2) economies of scale in purchasing large quantities of identical mounting systems, and (3) efficiencies in the labor associated with installing the mounting systems and modules.

3. Soft costs

“Soft,” or non-hardware, BOS costs includes such factors as customer acquisition costs, financing and contracting, permitting, interconnection and inspection, installation labor, and fixed and variable operations and maintenance.

Goodrich, James, and Woodhouse (2012) estimate that total soft costs constituted, on average, 47% of the US installed residential PV system price and 33% of the installed commercial system price in 2010, with variations around this average based on system size, location, and other factors. Soft costs vary widely across projects, and by region and locale (Ardani et al., 2012 and 2013; Goodrich, James, and Woodhouse, 2012). Feldman et al. (2013, p. 11) report soft cost price variance of about 50% in different states, for both small-sized residential and for commercial systems larger than 100kW, reflecting differences in “market size and maturity, incentive levels, regulatory costs, sales tax, and others.” Ardani et al. (2012, p. iv) explain:

> [S]oft costs… constitute a significant portion of total installed PV system prices… . Clearly, economies of scale help reduce… soft costs, particularly installation-labor and permitting costs, for large commercial systems compared with residential and small commercial systems. Among the individual surveyed soft-cost categories, customer acquisition and installation labor are the dominant contributors, while [permitting, interconnection and inspection] and labor for arranging third-party financing contribute relatively little cost. Thus, among [soft cost categories] customer acquisition and installation labor present the greatest potential for cost reductions for residential and commercial PV.

Several researchers compare soft costs in the United States to those of other countries, especially Germany, and conclude that large opportunities remain for soft-cost reductions, based on the fact that PV system prices are substantially lower elsewhere, despite having similar module and inverter prices. This finding suggests that substantial soft-cost reductions are possible for U.S. systems as well (Barbose et al., 2013). For example, Seel et al. (2012) identify lower costs in Germany, in part because residential rooftop systems tend to be larger there and interconnection costs are socialized (that is, they are charged to all electricity customers and not directly to the interconnecting PV generator), and because costs for customer acquisition, permitting, and interconnection are higher in the United States. Feldman et al. (2013, p. 25) explain that US prices "are high compared to most other major international PV markets, due largely to differences in soft costs." They report installed prices in Germany averaging about 50% lower than in the US, on a pre-tax basis, and thus suggest that there is significant near-term potential for soft-cost savings in the U.S.

With PV module prices declining rapidly, soft costs have accounted for an increasing portion of the average installed PV system costs. Some industry observers view soft costs as both a challenge and a major opportunity for reducing PV system costs in the future. Some analysts also contend that reducing soft costs is essential for making solar more cost-competitive (Dikmans, 2013; Adrani et al., 2012; Seel et al., 2012). The DOE *Sunshot Vision Study* (2012, pp. 86-87) identifies seven major areas of opportunity for reducing soft costs: (1) streamlining permitting and interconnection processes and disseminating best practices to a broad set of jurisdictions; (2) developing improved software design tools and databases; (3) addressing policy and regulatory barriers, as well as utility business and operational challenges; (4) streamlining installation practices through improved workforce development and training, including both installers and code officials; (5) expanding access to a range of business models and financing approaches; (6) developing best practices for considering solar access and PV installations in height restrictions, subdivision regulations, new construction guidelines, and aesthetic and design requirements; and (7) reducing supply-chain margins (profit and overhead charged by suppliers, manufacturers, distributors, and retailers) through industry growth and maturation.

Soft costs generally reflect economies of scale because smaller systems have equivalent or even higher costs for such aspects as customer acquisition, engineering design, permitting and inspections, financing, and contracting. In general, the larger the system, the lower the per unit costs associated with these factors. It is important to keep in mind, however, that many government incentive programs, such as grants, loans, special financing, and tax credits, are effectively reducing some of these costs for smaller systems (see Part IV). Also, some innovations in business models are helping to reduce customer-acquisition and financing costs for smaller systems and for groups of small investors whose interest in PV can sometimes be aggregated through group purchasing and installation programs and by way of community-based PV (Heeter & Nicholas, 2013, pp. 35-37).

Goodrich, James, and Woodhouse (2012, p. 12) summarize some of the economy-of-scale benefits associated with soft costs for large, ground-mounted systems, which are usually utility-scale. The benefits are clear, they explain, because some of the fixed soft costs for permitting and regulatory needs, project transactions, and engineering design will be amortized over a larger system size.

Yet, environmental and land-use permitting costs can be much higher for utility-scale systems. Roof-mounted systems seldom require environmental or special-use permits, but utility-scale ground-mounted systems sometimes raise concerns over preemptive land use, loss of habitat, and the possible displacement of sensitive species. Thus, utility-scale projects tend to have higher permitting costs (see Cart, 2014; Howland, 2014).

Similarly, land costs are seldom assigned directly to rooftop systems, but land costs are a factor for ground-mounted systems (as noted in Table 1). In a US study, Goodrich, James, and Woodhouse (2012, p. 14) found that land for PV installations averages about $5,025 per acre.

Another soft cost that is sometimes adjusted with differential effects on economies of scale is property taxes. Barnes et al. (2013, pp. 106-109) explain that PV system property taxes equate to anywhere from just a few percent of the retail price of electricity in several states to much higher percentages in other states. The state or local government rules applied to taxing residential, commercial, and utility PV properties can thus have a modest or strong influence on economies of scale.

Perhaps in response to these kinds of concerns for permitting and land costs, utility systems are often being sited on brownfield properties, on capped landfills, and on federal land. Sometimes government incentives help to support these kinds of applications, which assists utility-scale systems in lowering costs and thus further improves their economy-of-scale.

Taken as a whole, existing research on PV soft costs suggests that: (a) economies of scale mean soft costs represent a smaller percentage of total costs for large commercial and utility-scale systems; and (b) important opportunities exist for reducing soft costs for all system sizes.

IV. How Policies Sometimes Distort PV System Value

Almost every state offers at least one, and many jurisdictions have multiple, policies favorable to PV.[4] This project does not attempt to determine the extent of influence of existing policies.[5] Rather, in the preliminary way shown in Table 4, it simply points out some of the ways that existing incentives frequently target only certain system types or sizes or vary the amount of assistance depending on system type or size.

Grace, Donovan, and Melnick (2011, p. 1) refer to many different objectives for state-level renewable energy policies, and the propensity for policy makers to enact policies that explicitly "'tilt' the playing field toward achieving specific benefits… or supporting favored emerging technologies." Additional research is needed to thoroughly assess the differential effects of state or utility policies by system size, however, as outlined in Table 4, there are at least several common instances where existing policies do favor one system size over another. Although some policies favor utility-scale systems and others favor residential or other small rooftop systems, several policies do offer more incentives to smaller rooftop systems.

Table 4: Summary of Commonly-Used Policies/Programs with Effects on Value by System Size

Policy/Program	Federal, No. of States; No. of Utilities	Effects on Value by System Size
Direct cash incentives (buy-downs, FITs, grants, performance-based incentives, rebates)	24 states and DC; ~200 utilities	• Eight states provide larger incentives for government and non-profits that cannot qualify for tax incentives. • Rules sometimes limit participation to small systems; utility-scale systems are seldom eligible. • Dollar limits (per person or per system) sometimes favor smaller systems. • Accelerated depreciation rules generally favor taxpayers with larger tax appetites, and thus larger-scale systems and smaller systems financed through leasing arrangements.

[4] For more details, see Stanton, 2013, pp. 1, 7, and Table 1.

[5] Stanton, 2013 (pp. 38-41), points out in a general way that combinations of state policies in some jurisdictions are leading to more robust markets for solar PV. But, because of interactions amongst multiple policies, it is practically impossible to determine precisely the differential market effects of any single policy, in isolation.

Table 4: Summary of Commonly-Used Policies/Programs with Effects on Value by System Size

Policy/Program	Federal, No. of States; No. of Utilities	Effects on Value by System Size
Interconnection procedures and costs	41 states and DC have standards or guidelines	• Smallest systems are often exempted from interconnection costs, if any. • Smallest systems often enjoy expedited interconnection procedures, with speedy processing and minimal delays. • Mid- and large-size systems often pay 100% of their interconnection costs. • Larger-scale systems face more complex requirements and longer time to interconnect. • Interconnection costs for utility-scale systems are typically recovered from all customers.
Loans (special interest rates, loan guarantees, PACE)	PACE in 29 States and DC; State loan programs in 32 states and DC. Utility loan programs in 15 states.	• About half of state programs and most utility programs apply to residential systems, or residential and commercial. • About 10 states have special loan programs only for PV systems serving non-profit and public sector customers.
Net metering	43 States and DC	• Net metering usually values all or most PV system output at retail, but utility-scale systems must compete against wholesale rates. • About half of the states restrict the maximum size of residential systems in kW; Many others add restrictions for commercial systems. • System size limits are also usually restricted to producing no more than 125% of the customer’s annual kWh usage. • Several states allow aggregated or virtual net metering, where neighborhood or community scale systems produce energy that is netted at residential retail rates.

Table 4: Summary of Commonly-Used Policies/Programs with Effects on Value by System Size

Policy/Program	Federal, No. of States; No. of Utilities	Effects on Value by System Size
Personal income tax credit or exemption	Federal; 17 States	• Some programs have maximum dollar-amount limits, effectively promoting systems up to only certain sizes. • Revenues from the sale of electricity are subject to federal and state income tax, but net metering credits are exempt, thus favoring net metering as opposed to merchant sales.
Property tax credit or exemption	30 States and DC	• Sometimes only for systems dedicated to on-site usage; for net-metering, not for merchant plants. • Some states provide partial exemptions for utility-scale systems.
Sales tax credit or exemption on PV equipment	22 States	• Some states limit to only businesses (not residential), and minimum system size. • Other states limit to residential only.
Solar RPS standards, carve-outs, or extra credits	21 States and DC	• Many state policies include carve-outs or extra credits for solar-electric power at any scale, but a few carve-outs or extra credits apply only to distributed or customer-sited generation. • Small generators sometimes need help with aggregating and marketing solar renewable energy credits (SRECs).

V. Summary

All studies examined for this report identify lower costs for utility-scale systems, reflecting economies of scale in engineering, procurement, construction, and operation. Essentially, the studies agree on the existence of economy-of-scale benefits; however, some studies suggest that those benefits can be exhausted and reversed, in the largest utility-scale systems, though utility-scale systems would still remain below the cost of roof-top systems on a per kWh basis.

Recent studies of solar PV LCOE show a wide range of costs, depending on the major assumptions for equipment cost, investors' required rate of return, and whether the studies include interconnection, transmission, and grid operations costs and any available taxpayer or ratepayer funded incentives and subsidies. Differences in such LCOE analysis input factors account for the wide range of reported PV costs, varying from lows of about 10 cents to highs over 80 cents per kWh. The wide range of findings in LCOE studies is somewhat surprising, but continuity among multiple studies is a challenge because PV costs are changing rapidly, costs vary by region and sub-region, and existing cost studies lack concurrence regarding both the specific factors to include and the values to assume for those factors.

Currently, PV installations are increasing rapidly in the US, with rooftop applications doubling in number and capacity about every two years. Similar robust growth in utility-scale systems is expected to continue with several GW of additional PV installations each year through the rest of this decade. Some industry observers believe that PV system costs will continue to decline because of expected improvements in balance of system hardware and soft costs. It is not clear, though, whether the existing cost advantages of utility-scale and the largest commercial-scale systems will continue and grow, or if small rooftop system standardization, BOS, and soft cost reductions might conceivably reduce or even eliminate such cost advantages.

In general, incentive and subsidy policies can take any of three different approaches. Policies could support: (1) all systems equally; (2) only the most cost-effective systems while leaving others to adjust and adapt to unfettered market conditions; or (3) only the least cost-effective, helping to prop up an initial emerging market until it can survive on its own without special policy supports. This statement does not imply that any one of these approaches is right and the others are wrong; it is meant merely to clarify the choices that policymakers face and plausible goals for policy formulation, design, and implementation. Furthermore, designing any policy option to exclusively meet only one of these three goals without simultaneously producing at least some effects for the others could prove challenging. In the history of public support for solar PV, many policies were started a few decades ago when solar always represented an initial, emerging market needing extra support. Now solar costs have declined enough that policy makers can or should more carefully consider changes to reflect the first two policy approaches.

Future research should include more detailed sensitivity analysis for identification of different factors that affect costs and review the effects of existing and proposed incentives to best determine how they affect markets for PV at all system sizes. Policy makers need that information to enable them to make the best decisions about the design of incentives and subsidies for different system types and sizes.

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