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What's Blocking the Sun? Solar Photovoltaics for the U.S. Commercial Market

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EXECUTIVE SUMMARY

The commercial sector of the U.S. economy is in a unique position to drive growth in the solar photovoltaic (PV) market, widening it geographically as well as increasing its total size. The retailers, multinational companies, and small businesses that occupy commercial real estate in the United States make up 36 percent of national electricity consumption. The roof print of these businesses is vast and suitable for installing solar PV at scale. These potential investors are increasing their attention to the risks of climate change and seeking investment solutions that can meet their growing power demands as well as their sustainability mandates. However, more than 90 percent of commercial PV capacity installed is concentrated in only five states. Beyond pioneers in a few key states, why have more businesses not found solar PV to be the solution? Over the past year, our team interviewed members of WRI's Climate and Business Projects in order to understand the experiences of businesses exploring or participating in solar PV markets; those interviews inform this working paper.

This paper provides a snapshot of the current investment environment for solar PV in the United States from the commercial end user's point of view. The current installation trends, policy landscape, and economics are described in detail. Solar PV installations are concentrated in states with strong financial incentives and no regulatory barriers to distributed generation. Commercial investments have fared worse than the residential market during the economic downturn of the past two years. The policy landscape has improved since 2008, but multiple regulatory barriers remain at the state level and federal support is less certain after 2010.

An analysis of the hurdles remaining for solar PV finds that they are both economic and regulatory. The economics of a PV system is modeled in detail for four U.S. states, showing the potential impact of lower module

costs as well as state and federal policies on the levelized cost of solar power. PV has not yet reached cost parity with traditional power generation without a price on carbon, but its costs are expected to continue to decline and to eventually reach grid parity. The evolution of new business models and support policies is needed to stimulate deployment and accelerate this transition. Solutions are discussed that have the potential to “unblock” investment in this sector, including regulatory reform, demand aggregation, new financing mechanisms and public R&D investment.

With the objective of expanding the commercial market for solar PV, we make 18 strategic recommendations for solar industry members, commercial energy end users, and policy makers. Recognizing that the PV industry is in a highly dynamic phase and that these are only a few of the solutions that could put it on a sustainable path to grid parity, we conclude with questions for further research. At the end of this paper, there is a survey containing three sets of key questions, each targeted to different stakeholders.

In publishing this working paper, WRI seeks not just to recommend strategic actions but to elicit and synthesize additional insights about how to scale up solar PV. We hope that the reader will take a moment to access and respond to our survey online: http://www.wri.org/publication/whats-blocking-the-sun. Your confidential responses will provide insights for our upcoming work, informing future initiatives and outreach to the audiences best positioned to unblock the sun and grow the commercial PV market.

INTRODUCTION

Over the past decade, PV systems have steadily become less expensive and more economically viable, thanks to a serious decline in panel prices as well as reductions in associated installation costs.[1] As costs come down, major commercial energy users are starting to explore investment in rooftop solar PV generation. Companies in the United States and abroad are attracted to the idea of a clean, local source of energy that would help meet peak loads and reduce electricity bills. These major electricity consumers have thousands of facilities worldwide and vast roof space that could host solar PV systems. They are actively seeking opportunities to make solar PV projects work across their U.S. and global operations and are starting to make investments. However, in many regions, current PV economics do not satisfy the terms that most corporate energy managers consider viable for large-scale investment. Additional market and regulatory barriers also currently limit the potential for PV deployment.

The commercial sector—from Fortune 500 companies to real estate managers to small businesses—has an important and unique role to play in the deployment of PV at a scale that moves U.S. electricity generation measurably closer to being zero emissions. The commercial sector represents 36 percent of U.S. electricity consumption, and occupies commercial real estate that is better suited to large-scale PV installations than the residential sector.[2] At the same time, such installations are still a distributed form of generation, rather than centralized power plants. This avoids many of the transmission issues that hinder centralized renewables and also brings stability and efficiency benefits to the entire power grid. Additionally, commercial investors have access to the large amounts of capital needed to build gigawatts of PV capacity, if the economics can meet their investment requirements.

This working paper explores the potential for investment in solar PV by the commercial sector, with a focus on the investment and policy environment in the United States. Over the past year, our team interviewed several members of WRI’s Climate and Business Projects in order to understand the experiences of businesses exploring or participating in solar PV markets (see Box 1). Based on discussions with the private sector, this working paper discusses barriers that hold back broader and more rapid market growth. It highlights potential solutions that could be used to increase the deployment of the technology, and recommends “next steps” for key stakeholders in the private and public sectors. We end with a survey for readers, soliciting feedback on additional research ques-

Box 1 | **WRI Climate and Business Project Partners**

For ten years, WRI has engaged more than 60 companies through the U.S. Climate Business Group (Climate Northeast, Climate Midwest, and Climate Southeast*), the Green Power Market Development Group, and the California Affiliates program. These partnerships have advanced strategies for companies to thrive in a carbon-constrained economy. Peer-to-peer learning and collaborative engagement has helped partners develop innovative approaches to emissions management, develop and market climate-friendly products and services, and broaden their understanding of policy and market developments. Partners include:

Acuity Brands	Dupont Company	JPMorgan Chase & Co.	Rayonier
Alcoa Inc.	Eastman Kodak Company	Kimberly-Clark	Related
Advanced Micro Devices (AMD)	eBay	Lenovo	Staples
Apple	FedEx Corporation	Levi-Strauss & Co.	Starbucks Coffee Company
Archer Daniels Midland Company	General Electric Company	Michelin North America Inc.	Time Inc.
Baker & McKenzie	General Motors	MWV	TOTO USA
Baxter International	Georgia-Pacific	NatureWorks	Toyota Motor Sales, USA
Bristol-Myers Squibb	Google	Neenah Paper	United Airlines
BT Americas	Great River Energy	NewPage Corporation	United Parcel Service (UPS)
Caterpillar	Hewlett-Packard	News Corporation	United Technologies Corporation (UTC)
Cisco Systems	IBM	Northeast Utilities Systems	Wal-Mart Stores
Citi	Intel Corporation	OfficeMax	Wells Fargo
The Coca-Cola Company	Interface	Pactiv Corporation	Xcel Energy
Con Edison	Intuit	Pfizer	
Delta Airlines	Johnson Controls Inc.	Pitney Bowes	
The Dow Chemical Company	Johnson & Johnson	PPG Industries	

For more information, visit www.climatenortheast.org, www.climatemidwest.org, www.climate-southeast.org, www.thegreenpowergroup.org.

* WRI co-convenes its Climate Southeast workgroup with Southface Energy Institute. www.southface.org.

** Some of these companies provide financial support to WRI's climate program in the form of technical fees for project activities. Some are funders of other programs within WRI. A full accounting of WRI's funding sources can be found in our annual report, available online at www.wri.org.

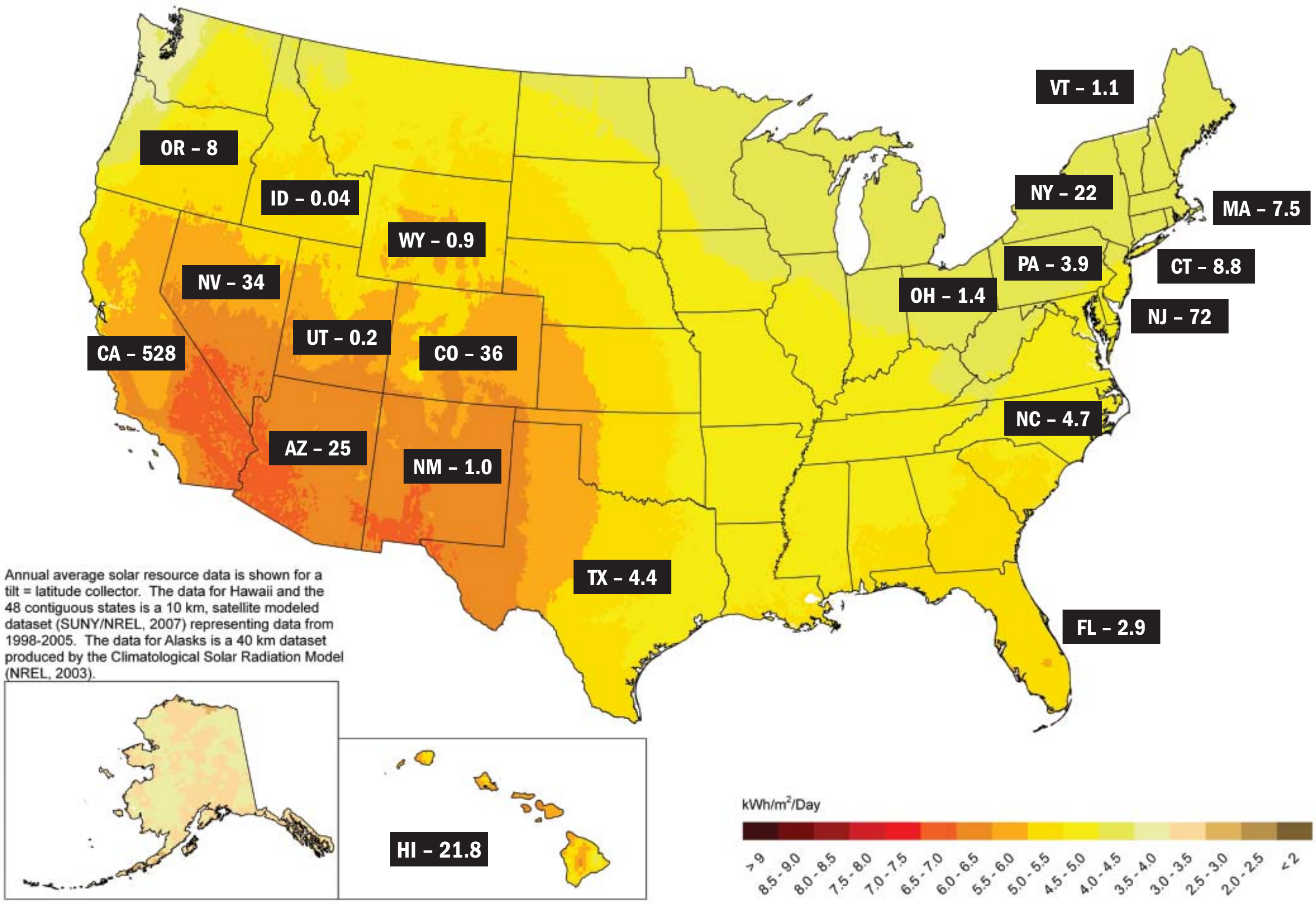
tions in order to inform future initiatives and develop public-private dialogue on the solutions for this sector.

Photovoltaic Installation Trends

Grid-connected solar PV installations in the United States grew on average 71 percent[3] annually from 2000-2008, totaling 1,102 megawatts (MW) by the end of 2008.[4] However, the highly concentrated U.S. PV market is dominated by only a handful of states with strong incentives: The top six states in terms of installed MW host 90 percent of total capacity.[5] Nonresidential PV installations (i.e. on commercial and public buildings) are even more concentrated, with over 90 percent in just five states.[6] The growth picture for commercial installations was clouded by economic distress in 2009. Whereas in 2009 annual grid-connected PV installations grew 40 percent compared with installations in 2008, installations for the commercial sector remained roughly the same as in 2008.[7]

The leading states in commercial end-user installations are largely the same as the leaders on the map of total installed capacity shown in Figure 1 (compare the rankings in Table A in Appendix I). Arizona is a minor exception (fifth overall but eighth in commercial installations) due to a few large utility-scale projects, resulting from somewhat different policies. A comparison of PV installation by state with technical potential (solar insolation) by states quickly shows that the strength of the solar resource alone is not a reliable indicator of where capacity is installed. Instead, installation patterns confirm that the drivers of solar PV installation are state incentives, electricity prices, and renewable portfolio standards. The sunniest states in Figure 1 do not, as a group, lead in solar PV investment; among

Figure 1 | Solar Resource and Installation (Grid-Connected MW) in 2008 by State



Source: This map was created by the National Renewable Energy Laboratory for the Department of Energy. Installation data also from NREL: Doris et al., 2009.

the top six states in installed capacity are New Jersey and New York, which lack exceptional solar resources. Internationally, Germany leads the world in PV deployment, yet has the same solar insolation as Alaska.[8] This shows that, even where there is only a moderate resource, there are many policy levers that can be used to capture the solar investment opportunity.

All of the states with the highest deployment levels (except California) have a solar-specific renewable portfolio standard (solar RPS), as well as state financial incentives. In the case of California, the long history of well funded incentives for PV preceding even the California Solar Initiative (CSI) is very important, but the aggressive general RPS, already high power prices and excellent insolation help as well.[9] Other states with good insolation, such as in the Southeast, have not seen similar adoption levels. Even some states that have favorable regulatory structures for solar (e.g. good net metering and interconnection policies) but fewer incentives, such as New Mexico, have had very minimal investment.[10] For more details about how interconnection, net metering, renewable portfolio standards, and incentive policies for solar compare state by state, see Appendix I.

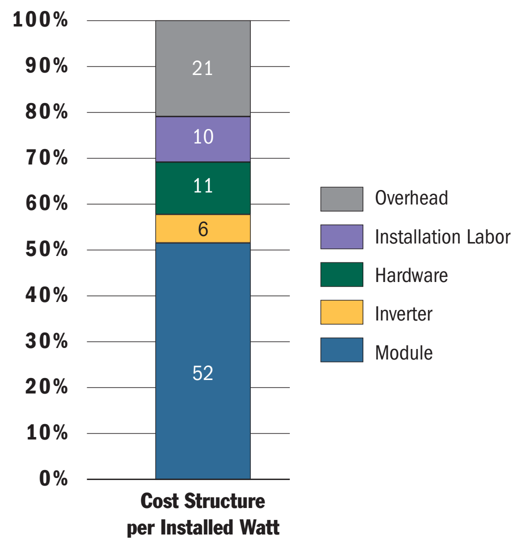
The Cost of Solar PV Today

The price of solar PV panels (or "modules") has plummeted by about 50 percent globally since 2008, attributable in part to slow demand during the economic crisis and to a global surplus of silicon.[11] This reduction improved economics for PV projects but also caused financial losses and bankruptcy for some module manufacturers. The average sales price of modules has fallen from a peak of over $4 per watt in 2008 to about $1.80 per watt in early 2010, and is expected to continue to drop.[12] Lack of demand and stale inventories necessitated these price reductions; although technological progress also reduced real production costs and thereby buffered the pain, the revenue impact has been quite significant. To illustrate, Sunergy reported that its average per watt sales price fell 50 percent between the first quarter of 2008 and the fourth quarter of 2009, while per watt production costs fell only 37 percent.[13] It remains to be seen how far this downward pricing trend continues, especially once global module demand picks back up, and what permanent changes it will bring to the PV supply market structure. These factors will determine the installed module price that commercial end users pay in the next one to five years and the future viability of PV for commercial on-site investment.

The most important PV cost metric, the installed price per watt (dollars/W), is a function of PV systems' cost structure and the specific system's scale. Figure 2 illustrates the typical cost structure per installed watt based on 2008 data.[14] Fifty-two percent of the cost is for the module, while non-module costs include the inverter, installation labor, additional hardware, and general overhead and development costs.[15] Non-module costs have historically declined faster than the cost of the actual panels, but in recent years they have leveled off while panel pricing has continued to decline.[16]

In a perfect market, the dramatically lower module costs post-2008 would proportionally reduce the total installed all-in cost. However, in practice this depends on whether the market is competitive enough to force integrators to pass on all of these savings and also on the size of the

Figure 2 | Cost Structure of a Typical PV System in 2008



Source: LBNL. 2009. Tracking the Sun, Part I.

system. Although installed module pricing data are scarce, early data from Lawrence Berkeley National Lab (LBNL) show that projects approved (but not yet installed) in 2009 had average installed costs of $6.10 per watt in California and $6.50 per watt in New Jersey.[17] This represents a significant reduction from 2008 ($2 per watt reduction in the case of California, and 70 cents per watt in New Jersey). However, these figures don't line up with the cost reduction one might expect when the key cost component falls by more than 50 percent. Lower pricing, in the $4 per watt range, is reported for large projects that enjoy economies of scale and is in line with lower module costs.[18] Such $4/W pricing, if it were consistent, would make PV competitive in sunny states where there are financial incentives and higher than average electricity prices.[19] But competing with today's power prices in other sunny states, including in the Southeast and Midwest, will require further cost reductions and/or incentives to drive solar below 10 cents per kWh.

Current U.S. Policy Landscape for Solar PV

The renewal of the federal tax credit for PV in 2008 came during a period of declining state-level incentives and stagnant installed costs. The average subsidy from state incentives in 2008 was 50 percent below its peak in 2002 (per PV watt installed).[20] The California Solar Initiative, for example, reduces the value of the rebate automatically at certain milestones of capacity installed in each utility territory to avoid over-subsidizing PV. New Jersey has been transitioning away from capacity-based incentives (CBIs), which pay a rate per MW installed upfront, and has moved toward almost complete reliance on solar Renewable Energy Certificates (sRECs).[21] In late 2008, the Emergency Economic Stabilization Act of 2008 (the "bailout bill") extended the 30 percent Investment Tax Credit (ITC) for solar through 2016 and also made the tax credit available to investor-owned utilities.[22] Further improvements were made in the 2009 American Recovery and Reinvestment Act (ARRA), which created the option of receiving the value of the tax credit as a cash grant instead. To receive the cash, projects must start construction by the end of 2010, apply by the end of October 2011, and operate commercially by the end of 2016.[23] The ARRA also funded a $60 billion loan guarantee program for renewable energy and transmission.[24] In the first round of cash grants, the U.S. Department of Energy (DOE) announced disbursement of $502 million, only $2.7 million of which was won by two PV project applicants totaling 520 kW.[25] Industry reports indicate that the solar market was more depressed than the wind market and did not have as many projects ready to apply and compete for the cash grant.[26]

State policies have weathered the financial crisis fairly well thus far, with some states using the stimulus money to create direct incentive programs for solar. Six state governments reduced incentive levels, either lowering the payment (per kWh or per kW) or reducing the maximum cap, for solar in 2009.[27] This may have been partially to avoid over-subsidizing, given the lower module costs and the better federal incentives. The four largest stimulus solar budgets were in Tennessee ($62 million), New York ($58 million), Florida ($45 million), and Arizona ($15 million).[28]

There was also broad movement on renewable portfolio standards: Eleven states enacted an RPS or made pro-solar changes to their existing RPS between September 2008 and September 2009. Seven states and Washington, D.C., made new provisions specific to solar energy. States are increasingly complementing their RPSs with feed-in tariffs, as seen recently in California, Vermont, and Oregon.[29]

The policy outlook for solar power is much improved today from its status in 2008, but some of these recent gains are part of the stimulus package that will expire in 2010. Of the $36.7 billion allocated to DOE by the ARRA, about 75 percent ($27.3 billion) of the money is relevant to renewable energy and efficiency implementation and research.[30] As it stands now, the cash grant administered by the Treasury will not be available to systems that start construction after December 31, 2010.[31]

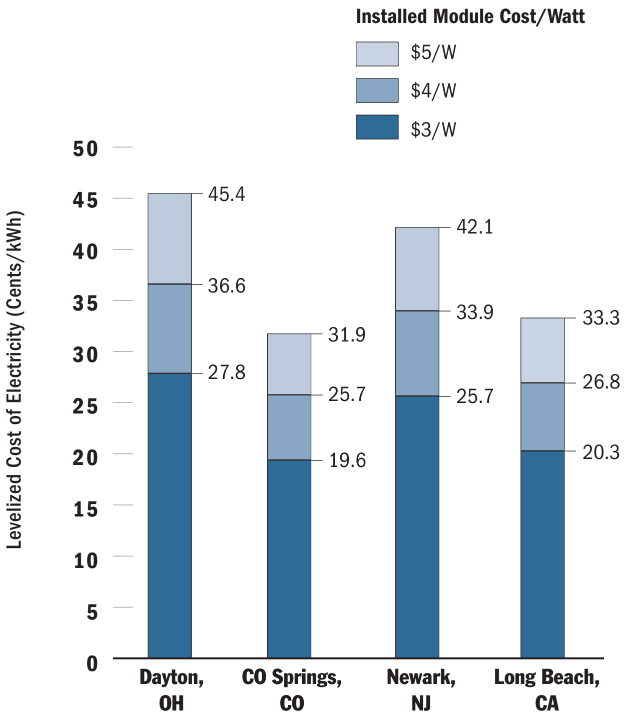
HURDLES (AND HURDLE RATES) FOR COMMERCIAL INVESTMENT

Cost Remains a Hurdle for Solar PV

In 2009, Ernst and Young conducted a cross-sector corporate survey of 132 executives in the United States and Canada on investment in renewable energy.[32] The survey found that 5 percent of respondent companies had installed on-site renewable energy in some form, but that it was still not a high priority for most companies. Business executives cited the higher cost of renewable energy as a major barrier to their switching over and expressed discomfort with their understanding of the logistics of installing renewable energy and its actual costs.[33] The cost of solar PV electricity has fallen, especially in the last two years, but it is still more expensive than average utility rates in most states with predominantly fossil fuel generation ("brown power").

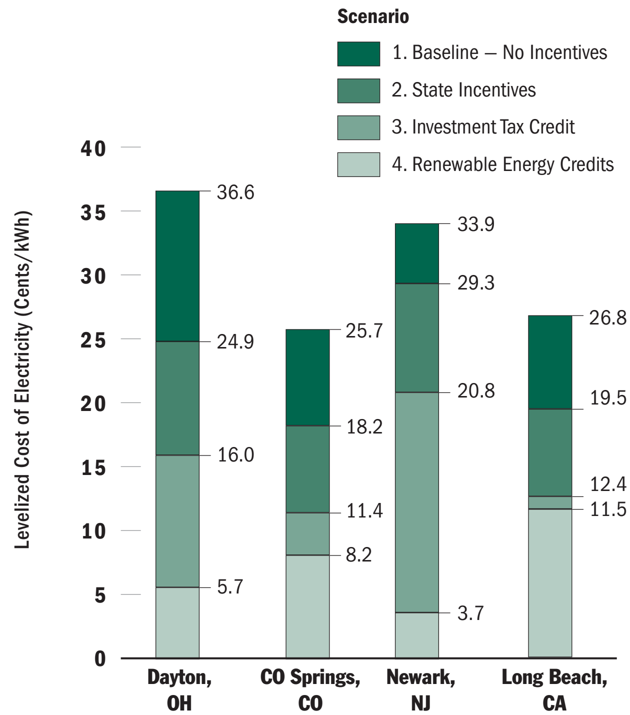
To illustrate how the cost of PV solar electricity varies by state and how it is affected by state and federal incentives, the author performed a financial analysis of four hypothetical projects in Ohio, Colorado, New Jersey, and California. The baseline results presented in Figure 3 are approximate representations of the levelized cost of electricity (LCOE)[34]

Figure 3 | Effect of Installed Module Cost on Levelized Cost of Electricity without Incentives, 2010



Source: WRI based on Bolinger 2009, NREL's Solar Advisor Model and DSIRE 2010a.

Figure 4 | Solar Electricity Costs in Four U.S States Including Effects of State and Federal Incentives



Source: WRI based on Bolinger 2009, NREL's Solar Advisor Model and DSIRE 2010a.

in each state without any incentive. The analysis applies normal tax rates specific to each state (corporate, sales, and property) even in states that grant tax relief to solar projects, in order to show the unsubsidized cost. Figure 3 above shows how the installed cost of the solar panel (dollars per watt) drives the cost of solar electricity.[35] The average 2009 retail prices (cents per kWh) paid for electricity in these states by commercial end users were 9.66 in Ohio, 8.16 in Colorado, 14.47 in New Jersey, and 14.04 in California.[36] These are well below today's baseline cost of solar without incentives, even at the lowest modeled cost of $3 per watt. This highlights the importance of continued cost reductions to the module and the balance of system in order to make PV a viable investment for commercial end users without continued incentives.

The results in Figure 3 are indicative only and should be considered along with their underlying assumptions, which are presented along with the methodology in Appendix II. Assumptions for the analysis were taken from Bolinger (2009)[37] and, where appropriate, from the NREL Solar Advisor Model.[38]

To demonstrate the impact of state and federal policies on the current levelized cost for solar electricity, Figure 4 shows how the LCOE is reduced by three distinct types of policy incentives that are available in these four states. The assumed cost per installed watt for all three cases shown is $4 per watt, and the baseline is again presented without incentives (case 1). The state incentive case (case 2) includes the effects of any state-specific tax relief granted to PV as well as available state financial incentives (both capacity-based and performance-based). The ITC case (case 3) includes how the federal ITC further reduces the LCOE below the state incentives alone. The value of the state Renewable Energy Certificate (REC) is added in case 4 and is based on current pricing available, except for Ohio where it is assumed that REC prices track the declining Alternate Compliance Payment (ACP) schedule at a discount. All assumptions are further described in Appendix II.

The prices in Figure 4 are close to what commercial investors might expect to pay per kWh if they invested directly in a PV system on their own balance sheet, and could capture all of the incentives available. However, it is important to note that certain incentives are not guaranteed, so the developer might still face uncertainty, e.g., a state program might not have sufficient funding to rebate all applicants in a year, or certain projects might not qualify. Especially for RECs, pricing and the term of the contract are powerful but uncertain drivers of the ultimate levelized cost.[39] Long-term contracts are not always available, so the REC values presented here are on the optimistic end. That said, it is interesting to note that REC contracts have the potential to be especially valuable in Ohio and New Jersey. The value of the REC in California and Colorado is lower, so projects there may depend relatively more on a variety of state incentives and federal tax incentives. In these two cases, the value of the state incentive is more certain than that of RECs, but does not subsidize solar as strongly.

Figure 5 | **Current versus Attractive Terms for Commercial Solar Investments**

	Performance Needed for Viable Commercial Investments	Overlapping Space for Negotiation	Current Economics for Solar PV
Payback	5–10 years	5 — 20 5 — 10	5–20+ years[a]
PPA contract	5–20 years; shorter preferred.	5 Prefer shorter / 5–20 Years 20 Most Common 20	5–20 years; 20 years most common[c]
Levelized Cost ($/MWh)	$65–150/MWh depending on the region	37 — 400+ 65 — 150	$37–400+[b]

Additional Parameters Affecting PV Commercial Viability

Incentives	Consistently strong, clear, accessible.	Strong in some states, non-existent elsewhere.
Regulatory ease (permitting, interconnection, integration)	Consistent and predictable.	Fragmented rules. Ease of interconnection and net metering varies widely between states. Building codes for PV can vary by city.
RECs	Liquid market with standard contracts and products, ability to sign long-term contracts that guarantee and additional revenue stream would significantly improve PV economics.	REC markets fragmented depending on state, with little liquidity or ability to contract forward beyond 3–5 years in some states. Sometimes held by the utility in case of utility rebate incentives, which can make it unattractive to use the rebate.[d]

a. Low range is based on a project purchased outright ("corporate balance sheet model") assuming $4 per watt in a state with good resources and incentives, while the high range represents a scenario with higher costs and limited incentives and would not be undertaken by most rational investors.
b. Low range illustrates a case with aggressive PV pricing (less than $4.50 per watt) and full advantage of federal and New Jersey RECs at good prices.
c. NREL, 2010b
d. NREL, 2010b

The expectations of commercial investors are difficult to characterize in general terms, but Figure 5 is an illustrative indication of acceptable financial terms for solar projects, as described by four Fortune 500 companies in interviews in 2009 and 2010 about their investment decisions. Acceptable terms (i.e., return on investment, payback period, LCOE) vary based on industry, company size, cost of capital, strategic focus, and the company's current power prices. It is clear that there is often still a gap between the financial performance of PV projects and the expectations of corporate management for good investments.

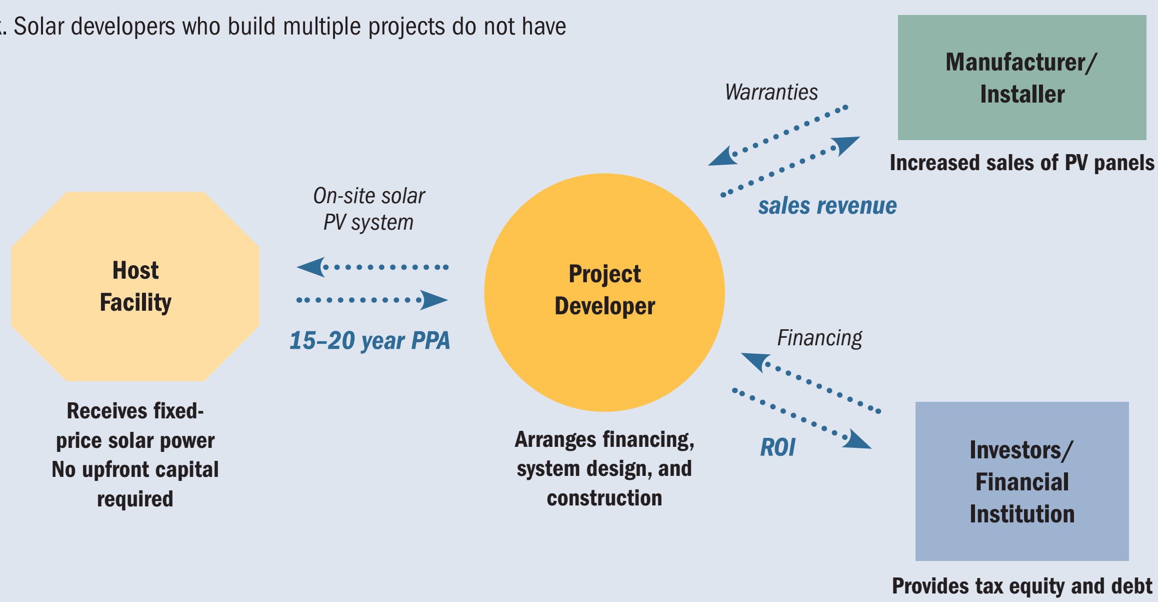
Many energy and facility managers compare the price of solar to their average utility rate, which is a comparison that overlooks the benefits of green power, the value of the associated REC, and the value of solar power's peak-time generation. However, companies cannot identify the value of distributed peak-time generation when their electricity billing structures are extremely complicated and the

Box 2 | **The Power Purchase Agreement Model for Solar PV**

The solar power purchase agreement (PPA) provides an option to buy power at a fixed price rather than having to invest cash directly in a PV system. The PPA model has been revolutionary for the solar industry. Under this model, buyers pay only for power produced while the solar developer owns the system. In some cases, the PPA model has helped make solar purchasing feasible for companies that cannot make the direct investment themselves (at the terms illustrated in Figure 5). Customers see no up-front cost, and avoid all operational risk and operations and maintenance responsibility. The PPA also allows efficient use of the federal tax credits and easier monetization of sRECs by the developer (if the power buyer does not keep them). A single rooftop PV system alone is too small to attract the attention of a bank. Solar developers who build multiple projects do not have the tax appetite for the tax credits, but they can build better relationships with the banks that supply tax equity and finance several PV projects in one combined tranche. However, solar PPA providers are still dependent on the banking industry for their tax equity capital, and this presents a challenge. In 2008 and 2009, tax equity deals were difficult due to the financial crisis, and the expected equity return rose on what is a fairly low-risk investment. Projects earning federal tax credits can be tested and put into operation before the tax equity investor buys in, but expected return on investment (ROI) still rose from about 7 percent to 9 percent, which significantly affected PPA prices.[1]

Note

1. Bolinger, 2009



Source: WRI

time-value of generation is not transparent in the pricing structure or is not rewarded under the net metering scheme. With energy prices currently depressed due to the economic slowdown, the future electricity purchase costs displaced by a PV investment remain unclear. Bankers in the energy sector report that, currently, "weak electricity demand has made it difficult for project developers to lock in long-term sales contracts at prices needed to make new wind and solar farms profitable."[40] It is evident from discussions with companies who have explored investing in PV that the incentives necessary to make a project viable involve significant legwork and investment in applications and fees. These costs are sometimes required even for an uncertain outcome in cases where state/utility incentives are awarded based on competitive bidding or when incentive programs are not fully funded up front to the end of the policy term. At best, the regulatory bureaucracy uses staff resources and increases the cost of overhead; at worst, it makes incentives hard to access and dissuades investment.

The current cost trajectory for PV module costs indicates that PV could eventually provide an affordable option for large commercial investors who want to diversify their electricity sourcing portfolios with a renewable energy source at a predictable price. In the short term, this will require continued incentives and financing programs, especially in order to spread the installation beyond a few leading states. The solar power purchase agreement (see Box 2) has been very instrumental in the deployment of solar PV observed to date. New business models for PV investment, as well as technological improvements on panel efficiency and balance-of-system (BOS) elements will be keys to making solar cost effective without incentives in the future. If climate legislation introduces a carbon price in the power sector, solar PV will reach "grid parity" even faster. The fact that countries with greater deployment of PV report lower prices per installed watt is an indication that continued investment in the United States can help spur further cost reductions which will further expand the markets for PV.[41]

Regulatory Hurdles for Solar Investments

More than 50 percent of U.S. respondents to the Ernst and Young renewable energy corporate survey cite regulatory uncertainty (e.g., "lack of clarity as to incentives, pricing structure, renewable energy targets") as a major barrier to their investment in renewable energy. Some of the incentives that are needed for PV investments—like the federal tax credit and various states' RECs—are complicated to access or have uncertain value.

The renewal of the federal renewable energy tax credit was certainly welcomed by the solar industry, but it remains a complicated incentive with high transaction costs. The ITC allows 30 percent of the value of the capital investment to be deducted from the tax burden of the project owner in the first year of operation. Project owners put in equity investment and make returns based on the value of the credit. However, to use the tax credit, its owner must have a sufficiently high tax burden to absorb the full value of the tax credit in that year, which disqualifies some companies. Most solar developers providing leases or PPAs opt to partner with banks that have sufficient tax appetite and capital and that charge fees for structuring and origination services. These deals are complicated to structure but are fairly low risk for banks. Some large corporate investors who have the tax appetite required do take the tax credits themselves, but this is very difficult or nearly impossible for smaller businesses. Thus, while the tax credit is a critical incentive for solar deals, it tends to encourage commercial investors to rely on large banks for equity investment, which is not a smart policy given the recent volatility of the banking sector. The cash grant (temporarily) resolves this problem, but projects beginning construction after the end of 2010 are ineligible for the grant. Without that option, it will be more difficult finding tax equity in a capital market that will be even more in demand (and thus costlier).

Solar PV owners that need to sell sRECs in order to make projects viable often find that they are not a very predictable source of revenue to count in cash flow projections. This is true whether the owner is the actual commercial end user or a developer providing a PPA. RECs can help on the margin, representing potential upside, but only in some specific cases can RECs make projects go forward that would not have proceeded otherwise. According to Mark Bolinger of the Lawrence Berkeley National Lab, "Attractive solar REC pricing has emerged in a number of states with solar set-asides, but without long-term contracting provisions, REC prices will likely remain too uncertain to be factored into financing decisions. In other words, without a long-term contract, neither Tax Investors nor developers nor site hosts are likely to fully value this expected revenue stream, and instead will consider any upside potential from the sale of sRECs to be icing on the cake."[42] Few states (e.g., New Jersey, Colorado) allow or require utilities to ensure compliance with their RPS by signing long-term REC contracts. Companies also experience transaction costs with RECs: Monitoring, verification, registration, and negotiations of off-take agreements can add to overhead. For a non-energy-sector business, the investment in systems and personnel to manage these processes will be spread over a relatively small number of MW installed. In states where utilities offer rebates for customers investing in solar PV, the customer is sometimes required to surrender the REC if it receives a rebate.[43] Companies who do this can no longer claim to be "solar-powered" because they have sold the right to the environmental attributes of their solar power and any potential claims about it.

Regulation of PV installation and grid interconnection is a key area where cumbersome regulation sometimes limits project viability and stunts investment. States have significant leeway to increase deployment of PV by establishing net metering and interconnection policies that do not add unnecessary costs and time to a project. They can do this by avoiding common pitfalls such as these identified by the Interstate Renewable Energy Council—[44]

- Arbitrary or low limits on the size of the system that can interconnect to the network;
- Net-metering schemes that restrict PV system owners from being paid for their surplus generation at the same time-of-day rates that they would pay for grid power, or that credit excess generation against the customer's bill but with time limits to the validity of the credit (i.e. restricting "rollover" credits);
- Requiring or allowing utilities to require unnecessary safety measures or technical screening beyond compli-

Table 1 | **Summary of Hurdles to U.S. Commercial Investment in PV**

Higher Cost of PV	PV still has a higher cost than traditional generation sources, especially when the latter do not pay for the societal cost of their carbon emissions. PV is only economical in states with strong financial incentives. For direct balance sheet investment, the payback period is longer than the investment horizons of most corporate entities. The PPA model can help overcome the up-front cost hurdle, but it still requires the same incentives to make the per kWh cost attractive to a traditional electricity customer.
Federal Investment Tax Credit Makes PV Rely Heavily on Financial Services Sector for Equity Investments	Tax credits can be used only by companies with sufficient tax appetites. This often requires renewable energy project developers to rely on the financial services sector for tax equity investment, which incurs transaction costs and creates significant uncertainties about future availability of capital. The alternative cash grant is currently only available for projects beginning construction by the end of 2010.
Fragmented Demand	Rooftop PV installations are inherently of smaller size than other types of power generation, meaning that transaction and overhead costs are spread over fewer MW. Commercial investors typically have fragmented demand and therefore cannot access aggressive pricing from developers without significant scale.
REC Value Difficult to Monetize	REC markets are illiquid due to states' definitional differences, and different tracking systems. The value of a REC in most markets more than a few years in the future is uncertain, and long-term contracts are thus difficult to secure.
Interconnection and Net Metering Regulations	Regulations vary state by state, sometimes by utility. Low limits on the size of the systems that are allowed to interconnect impede scale. Technical requirements are in some cases unnecessarily stringent. Certain states have restricted benefits in net metering schemes, limiting the amount of surplus generation which can be sent back on the grid and/or not allowing customers to retain credits for surplus generation against their bills beyond a limited time frame.
Local Building Codes Are Not Standardized	Codes vary based on municipality, and sometimes prohibit certain types of PV technologies. This complicates feasibility screening and increases regulatory risk in development process, making company-wide strategies difficult.
PPA Solar Model Not Available Everywhere Due to Legal Challenges	PPA agreements are not legal or are of questionable legality in certain regulated utility states if the PPA provider is not regulated by the PUC.

ance with the International and National Electrical Codes[45] for grid-tied systems, which adds cost and time to installation;

- Excessively long or unclear processes for evaluating system impact and deciding on interconnection approval, given that technical standards and procedures such as the IEEE 1547 and the National Electrical Code for grid-tied systems already exist.

Commercial end users attempting to install PV on their roofs have also found that local building codes and standards for approved technology vary from city to city. This patchwork of local codes complicates efforts to pursue a company-wide strategy for PV or to aggregate purchases on facilities as close as the nearest town.

In a number of states, the PPA model is impeded by legality issues stemming from language in state legislation, state constitutions, or public utility commission decisions.[46] States with regulated, vertically integrated utilities can require that any entity that sells power to retail customers must be regulated by the public utility commission (PUC). These rules were generally not designed to prevent solar PPAs, but to protect the customer and ensure safe grid operations. Nonetheless, PUC regulation is onerous and undermines the solar PPA business model; thus solar PPAs are not available in states such as Nevada, Arizona, Florida, Colorado, and Texas.[47]

UNBLOCKING THE SUN: EMERGING SOLUTIONS

Solar PV is cost effective today in only a handful of states with supportive incentive packages and otherwise high electricity prices. Beyond these, a significant gap remains between the financial performance of solar deals and the acceptable parameters for commercial investors. Large commercial investors can leverage their buying power to negotiate better panel pricing if they coordinate demand across their facilities, but many companies do not have the scale of demand or established relationships with equipment providers to do this. The solar industry is currently undergoing restructuring and consolidation due to the financial crisis, but it remains to be seen whether a more vertically integrated industry will emerge as beneficial to the commercial buyer. Changing dynamics in the solar industry—and in the larger power markets—make it an opportune and necessary time for companies to reevaluate their approaches to PV/renewables procurement.

Solutions to the hurdles discussed above are available and ripe for testing and further evolution. For example, a collaborative demand aggregation model could help currently fragmented segments of the market to access better pricing: Potential projects from individual facilities (or companies) would be jointly bid out together, generating select savings and attracting developers in a larger package. To help counteract difficulties with financing that are lingering even as the banking crisis lessens, two innovative solutions deserve attention. The results of Property Assessed Clean Energy (PACE) municipal financing and long-term sREC financing programs in a few states could be game-changing if they are implemented in the right ways. At this stage in the PV markets, it is equally timely for policy makers to plan their next steps carefully to encourage the long-term cost competitiveness of the industry, eventually without incentives. Public-sector involvement is especially important to make sure that the next generation of PV technologies, with potential to sell for less than $1 per watt, makes it past the technological “valley of death” between R&D and the commercial market. Although hurdles remain for solar PV, the solutions discussed in this section can help accelerate deployment on a wide geographical scale, avoid bottlenecks, and ensure that it becomes economically competitive without financial incentives.

Financing is slowly returning to the PV market after being frozen during the financial crisis, but it is not clear whether much capital will again be available at the terms that previously fueled the PV boom.[48] Financing structures for PV have largely evolved to efficiently capture the value of the federal tax credit (currently a large part of project revenues). Solar PPAs have been a large part of that because they allow a well-capitalized developer to arrange tranches of tax equity for relatively small projects, but the developer is another participant in the deal that requires its own compensation. Small PV projects do not have access to the large banks for tax equity on their own, and with a solar PPA they pay no up-front costs. Although they do not pay up-front with a solar PPA, they still frequently pay more per kWh than they would if they had direct access to the same tax equity and financed it on balance sheet, but their capital and tax appetites are more limited than those of banks.[49] The success of the solar PPA shows that continued financial innovation is important to continue to drive affordability and investments.

PACE financing is one such innovation that has picked up steam in 2009, partly due to the removal of a rule that made projects receiving subsidized energy financing ineligible for the federal tax credit.[50] Thirteen states passed laws authorizing these programs at the local level, and several municipalities in California and Colorado actually established working loan programs (see list in Appendix I). PACE loans are commonly made for both solar distributed generation and energy efficiency at attractive rates that allow low or no up-front payment.[51] The loans are repaid through a special assessment on the property and, because they involve a lien, can typically only be offered to actual property owners. In 2009, the Climate Smart loan program in the county of Boulder, Colorado distributed almost $10 million in loans to property owners for energy efficiency ($6.1M) and renewable energy ($3.9M) installations, authorizing one quarter of its $40 million initial bonding authority allowed by the state.[52] As PACE programs are piloted across the United States, it is important to monitor their results with an eye to commercial applications and determine whether there are unique modifications that can make them more effective for such mid-size investments.

The lack of liquidity and certainty in most state sREC markets makes it difficult to monetize their value and reduces their effectiveness as a financial incentive. Two potential solutions to improve REC markets are being tried in New Jersey. To provide longer-term REC price certainty to projects and to ensure that utilities are on track to meet their solar RPS compliance, the New Jersey state Board of

Box 3 | Landlords as PPA Providers: A Twist on the PPA Model in New Jersey

Hartz Mountain Industries, Inc., a New Jersey-based real estate company, is pioneering a twist on the solar PPA sales model. Hartz Mountain, acting as a landlord, is the PPA provider and its tenants are the solar customers. By investing in five solar installations on properties in its 39 million-square-foot portfolio, Hartz Mountain added 10 percent of New Jersey's total new solar capacity in 2009 and will produce about four GWh a year from its current portfolio.[1] There are benefits to such an arrangement for the tenants, who can sign a PPA that is coterminous with their leases, thereby eliminating the risk that they might leave the building before the PPA ends, and they can still buy affordable solar power as a hedge against market price increases. For Hartz Mountain, the novel solar offering is a competitive advantage and it earns a reasonable return on investments, thanks in large part to the value of New Jersey's sREC. Hartz Mountain's installations are partially funded by PSE&G's Solar Loan Program, a pilot solar financing program which was approved by the New Jersey BPU in April 2009. Under the program, PSE&G can finance 40 to 60 percent of the cost of panel installation in return for the future stream of sRECs generated by the panels. PSE&G will provide Hartz Mountain with $1.62 million in financing from its $105 million pilot program funds.[2]

Hartz Mountain has found that landlords have innate core competencies that facilitate solar investments but that barriers still remain in the process. As a landlord, Hartz has access to 39 million square feet of roof space, as well as existing relationships and already established contracts with potential customers. As a property management company, it has had to build the capacity to evaluate solar siting requirements and understand the technology performance and risk. Gaining investment certainty over solar power's long investment horizons and structuring financial deals that include sometimes uncertain values of environmental attributes have also been challenges faced in these first initial transactions of the model.[3]

Notes

1 Hartz Mountain, Ltd., 2010

2 Lee, 2009

3 McDermott, 2009

Public Utilities (BPU) required that they forward contract at least a portion of their sRECs rather than just buying on the spot market each year.[53] The utilities hold competitive tenders and projects compete based on their sREC pricing. Although RECs are still not a guaranteed revenue stream for all New Jersey projects because some projects do not win, the long-term contract is significant for those that do. Contracts awarded in 2009 averaged slightly over $410 per MWh for 10 to 15 years.[54] New Jersey sRECs have traded high on spot markets ($400 to $600 per MWh),[55] but before this decision, it was very difficult to secure long-term contracts for them.

A second and related solution is for the utility to offer financing in return for future streams of sRECs. The Public Service Enterprise Group (PSEG) of New Jersey is piloting a financing program which offers loans for a term of 15 years that can be paid back by sRECs, and it has demonstrated success stories (see Box 3).[56] In both the financing and the long-term contracting programs, the sREC price risk is no longer borne by the project developer, and it can therefore actually reduce the LCOE or PPA price. These two types of programs are possible in regulated states only by approval of the state public utilities commission, so the New Jersey BPU's participation was crucial. The New Jersey BPU approved the described utility purchasing until mid-2012, which leaves the long-term regulatory landscape uncertain. If the former illiquidity returns, it could significantly damage the New Jersey solar market.

WRI's Collaborative Solar Initiative (see Box 4) aims to develop a demand aggregation business model to reduce the cost barriers to PV by capitalizing on returns to scale in project economics. Returns to scale are clear in per-watt pricing data, and are the result of bulk buying power for materials like modules and mounting equipment, as well as the ability to spread overhead and transaction costs over a larger portfolio and to attract better financing.[57] Multi-MW systems can access returns to scale, but so can solar deals that combine a number of installations on separate facilities. Although not all the cost efficiencies associated with increasing the size of a single installation apply to aggre-

Box 4 | Case Study of WRI Collaborative Solar Pilot Project in California

To test the collaborative demand aggregation model, WRI and five Fortune 500 companies undertook a pilot project in California in 2009. WRI worked with these five partners from the Green Power Market Development Group and the Green Power Group California Affiliates[1] to map their roof space on facilities, prescreen it for PV feasibility, and then identified potential clusters where the close proximity would allow solar developers to reduce time and labor spent in screening and installation.

With this scoping exercise completed, in April 2009 WRI issued a request for proposals (RFP) to solar providers. The RFP included 19 facilities within an eight-mile radius, representing 1.1 million square feet of roof space from five companies. WRI requested contract proposals for 10-, 15-, and 20-year terms based on the third-party financing model as well as quotes of turnkey installation pricing (dollars per watt) for outright system ownership. Ultimately, proposals received in response to the Collaborative Solar Pilot Project were very encouraging. Prices for 15-year PPAs were competitive with average brown power rates. Prices for 20-year PPAs were below the brown power rates being paid by the commercial facilities participating in the RFP. Anecdotally, these prices were below the solar power prices quoted to companies for 2008 installations of individual facilities, even after the CSI rebate in the PG&E utility territory stepped down from $.22/kWh to $.16/kWh in 2009. Due to untimely real estate issues that removed several facilities from the cluster, the pilot did not go forward in its original grouping. However, it did help companies learn about solar purchasing strategies and gain experience standardizing their purchasing process. At least one Green Power Market Development Group member did go ahead with its own multi-facility aggregate investment in solar PV.[2]

Notes

1 http://www.thegreenpowergroup.org/us.cfm

2 Usas, 2010

gating multiple large installations, some of the benefits do translate. Efficiencies in sourcing components, shipping and warehousing materials, training labor, and staging construction all apply. Additionally, there are real benefits to the developer of having a single contract that guarantees a dozen projects of significant size.

Innovation in PV technology has powered major cost reductions in the past 20 years. Analysis by the Department of Energy estimates that the module cost of silicon PV panels dropped 87 percent for every doubling of installed capacity from 1992 to 2005. [58] This improvement is enormous, and there are many technology improvements on the horizon, but solar electricity still requires significant cost reductions before it is competitive with brown power without subsidies and without a price on carbon emissions. At current PV conversion efficiencies, panels would need to cost between $1 and $2 per watt installed in order to fall below 10 cents per kWh and approach unsubsidized competitiveness.[59]

Fortunately, panel efficiencies will not be static, and R&D prospects for cheaper modules and innovations on the BOS equipment are promising.[60] According to DOE Secretary Steven Chu, solar PV generation cost will decrease by a factor of two within the next five years if sufficient R&D investments are made.[61] Promising technologies like thin-film PV and building-integrated PV (BIPV) are available for commercial use, while others such as concentrating PV (CPV) and advanced thin-film alloy cells are emerging but are still viewed as riskier and have not penetrated the U.S. market.[62] Driving down the BOS cost will likely entail longer-lasting and panel-integrated inverters, more precise power conditioning equipment, and reductions on installation cost via system designs that are easier to mount, wire, and operate.[63] These technologies will provide large cost reductions if they can cross over from late-stage development to commercial acceptance and large-scale manufacturing. The scope and number of the technology improvements that are still in the laboratory and undergoing pilots make it clear that stable investment in research, development, and demonstration (RD&D) is crucial for unblocking PV's long-term success. Both the public and private sector can hasten this process by proactively investing in RD&D at consistently high levels of commitment. It is important that these efforts be well-coordinated and that public-private partnerships that share technology risk are ramped up.

CONCLUDING WITH STRATEGIC ACTIONS AND FURTHER RESEARCH

Deployment in the commercial sector will be crucial to expanding PV markets and manufacturing in the United States and globally. To install solar power generation capacity that makes a serious contribution to decarbonizing the U.S. electricity supply (and thereby reduce greenhouse gas emissions at a scale that is significant), the commercial sector—which consumes 36 percent of U.S. electricity—must be on board.[64] Due to the nature of their real estate roof print, commercial end users are also uniquely positioned to build sizable systems, which drives down cost. These end users have the ability to bring a great deal of capital to the PV market where there are sound investments to be made. Commercial end users can help bring PV to scale in these two senses, but their installations are still distributed generation, which contributes additional benefits to grid stability and efficiency.

The challenges to widening and deepening the commercial market for PV are real, but its potential is enormous, and the technology continues to progress toward grid parity. To accelerate progress toward competitiveness without incentives, and to widen the geographical scope of commercial PV deployment, this section recommends actions targeted to relevant stakeholders in the effort.

In publishing this discussion paper, WRI seeks not just to recommend strategic actions but to elicit and synthesize additional insights about how to scale up solar PV. This type of participatory research is especially important at a time when the competitive, technological, and policy landscape for PV is changing so rapidly. To this end, we conclude with questions for key groups of stakeholders in the form of a survey and look forward to receiving responses. We will analyze these responses carefully and distill insights for a future solar-focused publication as well as using them in future initiatives and outreach to the solar industry, commercial end users, and policy-makers.

- The survey questions are available to complete at: http://www.wri.org/publication/whats-blocking-the-sun
- All information submitted will be treated confidentially and will not be associated in any way with identifying information about its respondent, except where respondents are grouped and identified by type (i.e. "commercial end users," "government-affiliated, " "industry members," or "nonprofit/academic").

For Corporate Energy Managers and Financial Officers

Recommended Actions:

1. Perform comprehensive, company-wide initial screening of facilities for PV feasibility, including acceptable rooftop characteristics, legal/rental tenure, adherence to local building codes, and available state incentives.
2. Bid out potential PV projects at proximate facilities to developers in a package to capture returns to scale. Explore collaborating with other companies that own neighboring facilities.
3. If working with a group of companies on a combined purchase, build agreement early on terms that are acceptable to the whole group (contract length, preferred technology, financial criteria for developer).
4. For sites that are identified, bring facility managers into the process early on.
5. If internal capacity exists or could be sourced to perform operation and maintenance on solar installations, solicit bids from solar developers for turnkey installation or leasing options in addition to their PPA proposals.
6. If considering a large PV investment or a portfolio of solar assets on company facilities, calculate the internal tax appetite that would be required for the company itself to absorb the benefits of the ITC. Discuss the potential benefits to project returns and the feasibility of this structuring with the accounting department and/or with tax counsel experienced in renewable energy.
7. When assessing the economic viability of solar PV installations, include the best reasonable estimates of the value of the associated renewable energy credit (REC), and the value of solar power's peak-time generation.
8. Incorporate risk analysis of traditional energy markets when formulating company energy strategies and when making solar decisions. Consider quantitatively and qualitatively the risks over the 20- to 30-year time horizon of not investing in renewable energy and of continuing to rely on traditionally generated electricity markets, given the specific markets on which the company/facility relies.

Questions for Corporate Managers:

- In comparing the cost of solar electricity with continued grid purchases, what assumptions are made about power prices up to 25 years in the future? Are sensitivities performed that include the impact of a price on carbon in the power sector?
- Which risks related to PV on-site investment is the company most equipped to bear? Which is it least equipped to bear? (Examples of risks include permitting, development risk, resource risk, technology performance risk, interest-rate risk for equipment purchase, REC price-risk, regulatory risk, etc.)
- Do you use utility rebates if it requires surrendering the RECs? How would/do you market the RECs generated by the project? Do you retain/retire the project RECs in order to claim against renewable energy purchase targets or swap solar RECs for national (less valuable) RECs? Has your approach changed over the past three years? If so, please describe how.
- Are there changes to existing regulations concerning RECs (or sRECs) that would increase their value to a potential PV project?
- What range of module pricing per installed watt have you observed on the market in 2009 or 2010? Have you

observed differences in pricing for projects of differing sizes?

- What design features need to be included in a federal RPS proposal if it is to support solar PV and the market for Solar RECs? (Some potential design features include, but are not limited to, level of ambitiousness, unbundled RECs, solar multipliers, and alternate compliance payments at a certain level).
- What would be a feasible solar carve-out target in a federal RPS, achievable without major equipment or labor supply bottlenecks, by 2020? 2030?

For Solar Developers and Integrators

Recommended Actions:

1. Continue searching for organizational efficiencies that reduce installation labor time and development costs and test new non-module equipment with the potential to reduce BOS costs.
2. Prepare for step-downs of incentives paid per kWh in leading states like California and New Jersey and formulate entry strategies tailored to next markets such as Ohio, Colorado, and Pennsylvania.
3. Develop plans for selectively piloting promising PV technology beyond crystalline PV in the future, such as building-integrated PV, concentrating PV, new inverter, or new maximum power point tracking (MPPT) technologies. Explore joint pilot project options with technology manufacturers and guarantees that they could provide to share risk. Approach states, national labs, or the DOE for R&D funding of public-private partnerships to test new technologies on some small percentage of project pipeline.

Questions for Solar Industry:

- Where do you see the strongest potential for reduction of BOS costs? What types of changes led to the steady decline in non-module costs over the past 10 years?
- Which technologies are proven in the lab or field-tested but are still considered risky in practice by developers? What about by banks?
- Where is increased R&D most needed to target technology gaps?
- Given the state of equity markets today, how important is the cash grant? Are there any other potential sources of equity that could replace the dominance of banks in the RE tax equity space (i.e. pension funds, private equity, etc.)?
- Does your cost structure differ dramatically from that described for 2008 data on page 3? How has the drop in module price changed that cost structure?
- What are the design characteristics of an RPS or REC tracking systems that make it easier to monetize the value of a REC?
- What are key elements of reasonable interconnection and net metering regulations?
- Do you follow the creation of new PACE programs and actively plan to target turnkey services to projected additional demand in those areas? If not, why?
- Do you see the turnkey model or the PPA model as the most viable currently? Do you expect this to change in the future or for any other models to dominate?
- What are the drivers/size thresholds for returns to scale at the facility level? What are the drivers/size thresholds for returns to scale at the deal level?
- How might the economic crisis/increased competition in the PV market change your business model, the suite of services you offer, or areas of investment in internal capacity in the next five years?

For Federal, State, and Local Policy Makers

Recommended Actions:

1. (Federal): Ensure funding for solar incentives beyond the expiration horizon of the ARRA so as not to leave solar with an "incentive gap." Include funding that can be used by states to maintain funded or to expand successful solar programs. Study extension of the manufacturing tax credit and the cash grant program.

2. (Federal): Reform the federal tax credits at their next renewal to simplify and streamline their application, or create a different incentive that companies can directly access without an intermediary.

3. (Federal and state): Establish and maintain strategic funds for public-private partnerships to commercially demonstrate next-generation PV technologies beyond crystalline silicon (i.e., BIPV, CPV, advanced thin film, micro invertors, MPPT, and other emerging technologies).

4. (State): Evaluate state interconnection/net metering standards regularly against best practice standards to make sure that they facilitate maximum deployment of solar energy and avoid the pitfalls identified on page 7.

5. (State): Allow for the sale of RECs unbundled from associated electricity within state RPS to allow sale of RECs from distributed generation, and ensure that all of the environmental attributes of the REC are clearly defined.

6. (State utility boards): Allow and encourage a long-term contracting model for regulated utilities to source RECs and improve financial viability of RE projects by providing long-term REC off-take agreement and/or financing program.

7. (Local): Study the benefits of and feasibility of a bonding initiative to fund a PACE loan program in your jurisdiction. Identify the agencies that would be well-suited to administer it.

Questions for Policy Makers:

- Is it possible that solar building codes could be standardized across a state or region? Which agencies and/or standards boards would be best suited to making suggestions for standardized building codes?

- What are the biggest challenges faced in permitting small PV installations? Medium and large size?

- Do states have regular, effective processes to review their interconnection and net metering policies against accepted best practices?

- Do public entities in your jurisdiction make solar investments? If so, what type of financing model do they use?

- The executive branch recently announced that the federal government will reduce its greenhouse gas emissions 28 percent below 2008 by 2020. How will this affect investments in renewables by government agencies?

- How can the federal government and DOE better support solar technology in between the demonstration and commercialization stages?

- Do your states' laws, constitution, PUC decisions, and/or net metering regulations prevent the sale of electricity through third-party power purchase agreements (where the PPA provider is not regulated as a utility by the PUC)?

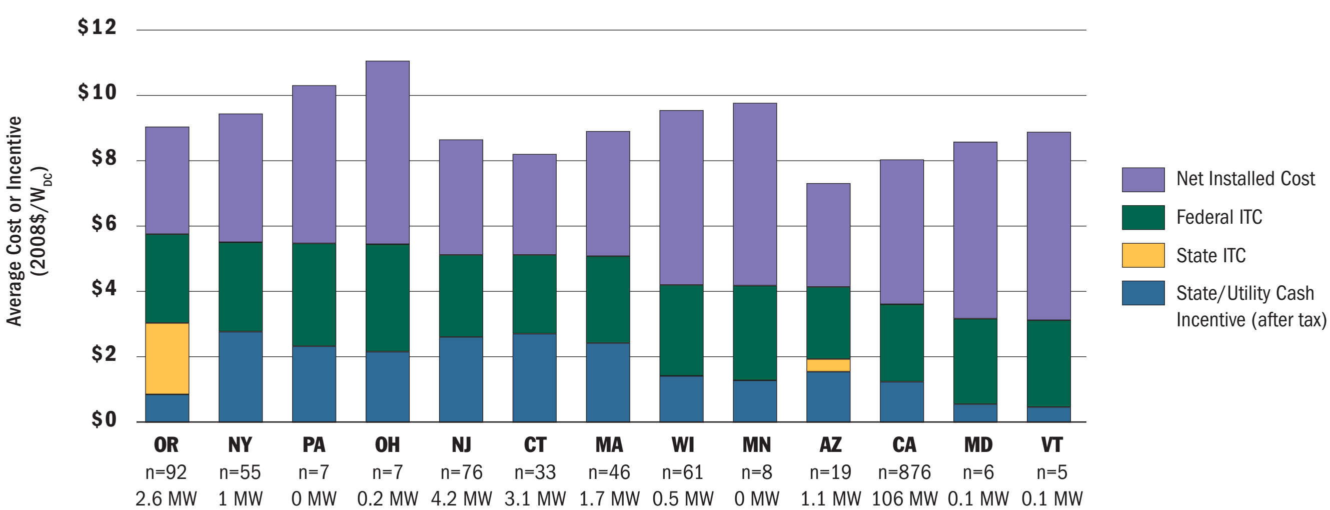
APPENDIX I: ADDITIONAL POLICY INFORMATION

Table A. **State Rankings in Installation and Policy Indicators**

State	Rank - Commercial Installation (MW)	Rank - Total Capacity Installed (MW)	Installed MW Grid-Connected	Net Metering - Best-Practice Grade	Interconnect - Best Practice Grade	Total RPS	Solar/DG Provisions in RPS
California	1	1	528.3	A	B	33% by 2020	None
New Jersey	2	2	70.2	A	B	22.5% by 2021	5,316 GWhs by 2026
Nevada	3	4	35.7	B	B	25% by 2025	1.5% solar by 2025
Colorado	4	3	34.2	A	B	30% by 2020	3% by 2020
New York	5	6	25.3	D	B	24% by 2013	0.13% DG by 2013
Hawaii	6	7	21.9	C	F	40% by 2030	None
Connecticut	7	8	13.5	A	D	23% by 2020	None
Arizona	8	5	8.8	A	C	15% by 2025	4.5% DG by 2025
Massachusetts	9	10	7.7	B	B	15% by 2020	400 MW PV by 2020
Oregon	10	9	7.5	A	B	25% by 2025	20 MW PV by 2020

Source: Columns 1 and 2: IREC 2009a. Column 3: Doris et al., 2009. Columns 4 and 5: IREC 2009b. Columns 6 and 7: DSIRE 2010b.

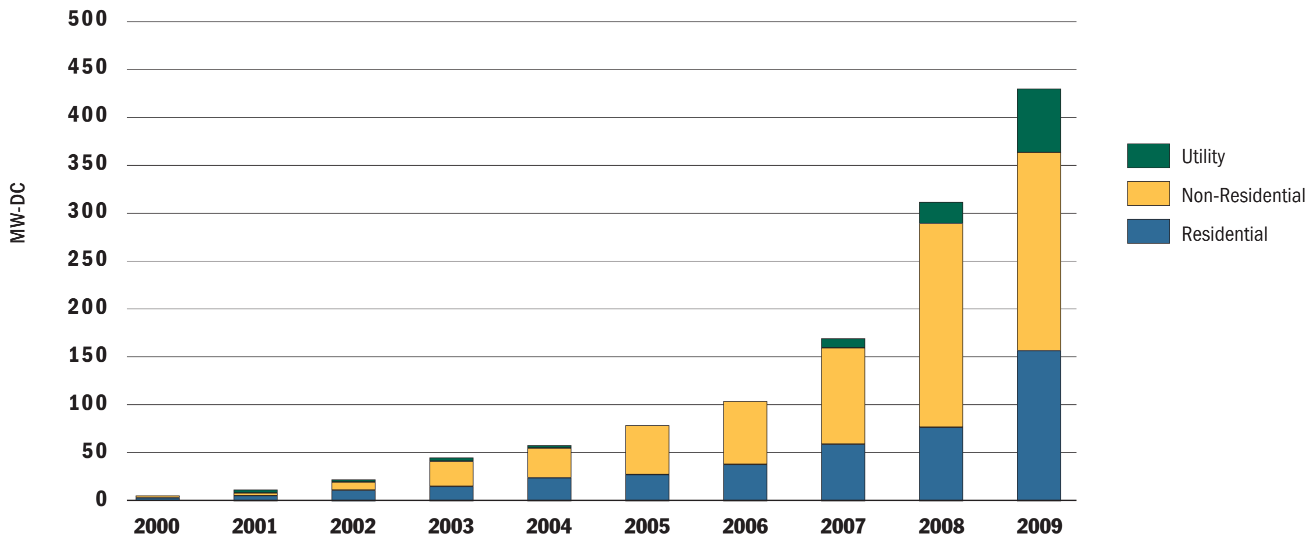
Figure A | Relative Contribution of Federal and State Incentives to Buying Down the Net Installed Cost of PV in Various States



Source: Wiser, et al., 2009

Notes from LBNL: We assume that all systems >10kW are commercial unless identified otherwise, and that direct cash incentives for commercial systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. State ITCs are calculated as described in Appendix C. Results shown for NJ are based solely on systems funded through the CORF program. States are excluded from the figure if the database contains fewer than five commercial PV systems installed in that state in 2008.

Figure B | PV Installation by Year and End-User Type



Source: Interstate Renewable Energy Council, 2010

Nonresidential end users have increasingly dominated PV installations since 2002, installing close to twice as much PV in 2008 as residential and utility end users combined.[65] Nonresidential installations include commercial end users as well as public entities (government, military) but not utility installations, whose use of PV only picked up recently. This pattern is partly due to the economics of larger systems beating residential pricing, but equally important has been the fact that the federal tax credit was more generous for nonresidential projects until 2009.[66]

List of States with Legislation Permitting PACE Programs

As of April 1, 2010, the following states have laws in place that give local governments the option to implement a PACE program, according to the Database of State Incentives for Renewables and Efficiency (www.dsireusa.org): California, Colorado, Florida, Hawaii, Illinois, Louisiana, Maryland, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Texas, Vermont, Virginia, Wisconsin. IREC's 2009 Annual Report cites thirteen states that passed legislation allowing local governments to create PACE programs from late 2008 to late 2009.

APPENDIX II: LEVELIZED COST OF ELECTRICITY CALCULATIONS

The LCOE is calculated using the National Renewable Energy Lab's Solar Advisor Model (SAM).[67] Based on operating assumptions about the technology, location, cost, incentives, and required rates of return, SAM uses a discounted cash flow model to calculate the LCOE. The LCOE is the price per kWh needed for all kWh to cover the present value of the total cost of building and operating a generating plant, including the cost of capital, over its economic life. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

The baseline results presented in Figure 3 are an approximate representation of the levelized cost of PV electricity in each state without any incentive whatsoever. The analysis applies the normal tax rates specific to each state (corporate, sales, and property) even in states that do actually grant tax relief to solar projects, in order to show the unsubsidized cost. Figure 4 shows how the LCOE is reduced in three scenarios, each with another policy added in. The assumed cost per installed watt for all three cases shown is $4 per watt, and the baseline is again presented incentive-free. The state incentive case includes the effects of state tax relief policies applicable to PV as well as available state financial incentives (both capacity-based and performance-based). The ITC case shows how the federal ITC further reduces the LCOE below the state incentives and includes both. The REC case further includes the value of the REC in the state, based on current pricing available or future REC market assumptions as necessary. Depreciation schemes are not varied for the incentive vs. non-incentive cases but match as closely as possible the applicable state depreciation scheme.

Assumptions are drawn from Bolinger (2009) and from the default inputs in the Solar Advisor Model where appropriate. Additionally, state-specific policy parameters (see table below) are drawn primarily from the DSIRE database.[68] These assumptions and scenarios are not to be taken as authoritative or specific to any particular project but are indicative and useful for such a comparative cross-state analysis. The project is assumed to be balance-sheet-financed without project-specific debt and must meet the specified hurdle rate (here, 10 percent). The locations chosen in each state were ranked on the higher end of the resources of the sites that had data available in SAM, but resources will vary across states.

Major assumptions common to all cases:

Parameter	Value	Metric
System Size	149	kW
Lifetime/Analysis Period	25	years
Year Placed in Service	2010	year
Inflation Rate	2.5	%
Company Hurdle Rate (Real Discount Rate)	10	%
Federal Corporate Tax Rate	35	%
Insurance	0.5	%
Federal Depreciation	MACRS Mid-Quarter Convention	
Federal ITC	30	%
System Degradation	0.5	% Annually
Availability	100	%
Installed Cost per Watt Pre-sales tax	3 to 5	$/Wdc
O&M Fixed Cost by Capacity	25	$/kW-yr
O&M Escalation (above inflation)	0.5	%

Assumptions specific to state cases:

	LONG BEACH, CA	NEWARK, NJ	DAYTON, OH	COLORADO SPRINGS, CO
State Corporate Tax Rate (Baseline)[1]	8.84%	9.00%	0.26%	4.36%
State Corporate Tax Rate (PV-applicable)[2]	Same	Same	Exemption possible with energy conversion facility certificate granted by Dept. of Taxation[3]	
Property Tax Rate (Baseline)[4]	0.68%	1.78%	1.81%	1.08% Note: The incremental cost of renewable energy generation equipment is exempt from property tax. See explanation below.
Property Tax PV -Exemption?[5]	Yes	Yes	Yes, with energy conversion certificate[6]	Yes
Sales Tax Rate (Baseline)[7]	9.75%[8]	7.0%[9]	5.5%	2.9%
Sales Tax PV – Exemption?	Yes	Yes	Yes	Yes
State Depreciation Scheme	12 years straight line	5-Year MACRS	5-Year MACRS	5-Year MACRS
State CBI ($/W)	n/a	Only if <50kW[10]	$3.50/W for traditionally owned (not PPA) projects. Maximum of $150,000 or 50% of total investment[11]	$2/W provided by the Xcel utility program, up to $200,000 maximum[12]
State PBI ($/kWh)	$0.22/kWh for 5 Years (valid for projects in SCE region)[13]	n/a	n/a	n/a
State REC Value ($/MWh - taxable)	$20[14]	$395[15]	$350 declining to $43[16]	$65 available in Xcel Solar Reward's Program[17]
Years of REC Value	15 Years	15 Years	15 Years	20 Years[18]
Note on REC Assumptions	Average of REC prices and term quoted by four solar developers in the WRI California Solar Collaborative Initiative RFP Responses.	Value put on sRECs within the long-term contracting structures available from PSEG.[19] Other utilities also offer similar programs for sRECs at higher prices but contract less. These contracts are not guaranteed in NJ as they are competitively bid.	Ohio has a declining Alternate Compliance Payment (see below). Assumes that REC prices follow the ACP schedule but at a discount to be conservative. Current discount to ACP is approx. 13%. There is not currently a robust long-term market for sRECs in OH, i.e., more than a few years ahead.	Per the Xcel Solar Reward's Program

Notes

1. Bolinger, 2009 and The Tax Foundation, 2010
2. DSIRE, 2010b. State summary pages for photovoltaic incentives each indicate where tax exemptions available.
3. DSIRE, 2010c
4. New York Times, 2007
5. DSIRE, 2010b. State summary pages for photovoltaic incentives each indicate where tax exemptions available.
6. DSIRE, 2010c
7. Federation of Tax Administrators, 2008. Unless otherwise noted in cell.
8. California State Board of Equalization, 2010
9. DSIRE, 2010b. State summary pages for photovoltaic incentives each indicate where tax exemptions available.
10. Barnes, 2010
11. Milano, Date unspecified
12. Xcel Solar Rewards Program, 2010
13. Unnamed Author, 2010. Long Beach is in Southern California Edison utility region at Step 5 incentive levels.
14. Average of REC prices and term quoted by four solar developers in the WRI California Solar Collaborative Initiative RFP Responses.
15. PSEG, 2010
16. DSIRE, 2010d
17. Xcel Solar Rewards Program, 2010
18. Xcel Solar Rewards Program, 2010
19. PSEG, 2010

Note on Ohio REC Assumptions:

Ohio has a declining Alternate Compliance Payment (see below). Assumes that REC prices follow the ACP schedule but at the current discount. Current discount to ACP is approximately 13% based on the average of year-to-date prices listed on the Flett Exchange.[69] There is not a robust long-term market for sRECs in OH, that is, more than a few years ahead. The Ohio RPS includes a provision wherein utilities can appeal to the Public Utilities Commission of Ohio and claim force majeure in the event that they can demonstrate that compliance with the solar RPS would raise their rates more than 3%. If the commission approves such an appeal and "determines that resources sufficient to meet the obligation are not reasonably available," the compliance requirement is waived for the year and postponed for subsequent years.[70] All of these uncertainties combine to make the Ohio sREC value very difficult to forecast, so it must be emphasized that the value calculated for the Ohio RECs is a rough estimate of the potential value and is far from guaranteed.

	ACP	Trading at today's discount (13%)
2009	450	13%
2010	400	350
2011	400	350
2012	350	306
2013	350	306
2014	300	263
2015	300	263
2016	250	219
2017	250	219
2018	200	175
2019	200	175
2020	150	131
2021	150	131
2022	100	88
2023	100	88
2024	50	44
2025	50	44

Colorado Property Tax Assumptions:

Colorado's property tax is not levied on the incremental cost of a renewable power generation system. According to DSIRE (2010e), the latest "nonrenewable facility value was determined to be $1,128 per kilowatt (KW) for renewable energy projects up to 2 megawatts (MW)." Therefore, the property tax rate is calculated on that $1,128 per MW only.

ENDNOTES (Correspond to Bibliography)

1. Wiser et al., 2009
2. EIA, 2009. Refers to retail sales of electricity only.
3. Combined Average Growth Rate (CAGR) from 2000-2008.
4. GreenTech Media, 2009a and IREC, 2009a
5. IREC, 2009a
6. IREC, 2010
7. IREC, 2010
8. Eurobserv'er, 2009
9. California has an aggressive RPS but no specific solar provision within it. To date, the statewide RPS has not been a key driver for solar rooftop PV installations because it did not allow utilities to buy RECs without buying the associated power, and hence they have built more utility-scale solar to meet the RPS. This rule was changed in 2009, so the state will now allow distributed rooftop solar PV value to have a role in meeting the RPS.
10. IREC, 2009b
11. Polysilicon is used to make crystalline silicon PV panels.
12. Navigant, 2010
13. Seeking Alpha, 2009
14. Wiser et al., 2009
15. Non-module costs are also sometimes referred to as the "balance of system," but that term technically does not include overhead.
16. Wiser et al., 2009. This was observed for 10 years (between 1998 and 2008).
17. For commercial projects larger than 100 kW whereas residential prices were slightly higher, LBNL notes that these costs are provisional and anecdotal industry sources suggest they may have come down even further for projects in 2010.
18. Chu, 2010
19. Regions/states with average commercial electricity prices (in 2009) at or above 10 cents per kWh included New England, the Mid Atlantic, the West Coast, Hawaii, and Alaska. Sunny, in this case, is defined as approximately 1,350 kWh/kW per year.
20. Wiser et al., 2009
21. Bolinger, 2009. sRECs represent 1 MWh (or the energy equivalent of 1 MWh) of solar energy generated. They can be used to comply with separate solar provisions or "carve-outs" in state renewable portfolio standards. sRECs can be awarded to solar electricity and/or solar thermal energy, depending on the specific technologies' eligibility in the state RPS.
22. SEIA, 2009

23. Bolinger, 2010
24. SEIA, 2009
25. Photon News, 2009
26. Greentech Media, 2009b
27. This policy update only covers September 2008 to September 2009.
28. IREC, 2009a
29. IREC, 2009a
30. Including $16.8 billion for energy efficiency and renewable energy, $4 billion for renewable energy loan guarantees, $4.5 billion for smart grid and transmission, and $2 billion for R&D, including the ARPA-E program.
31. U.S. Department of the Treasury, 2010
32. Ernst and Young, 2009
33. Ernst and Young, 2009
34. LCOE is the per-unit life-cycle cost of one kWh. It is the price per kWh needed to cover the present value of the total cost of building and operating a power plant, including the cost of capital, over its economic life. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).
35. Installed cost here refers to all-in cost per watt, before sales tax.
36. Average costs are illustrative. A better comparison would take into account the time-of-use rates for commercial buyers whose pricing structures are based on those rates, given the fact that solar generates close to peak load.
37. Bolinger, 2009
38. NREL, 2010a
39. The Ohio RPS includes a provision wherein utilities can appeal to the Public Utilities Commission of Ohio to claim force majeure in the event that they can demonstrate that compliance with the solar RPS would raise their rates more than 3 percent. If the commission approves such an appeal and "determines that resources sufficient to meet the obligation are not reasonably available," the compliance requirement is waived for the year and postponed for subsequent years. New Jersey has a similar clause if the total cost of solar incentives during a reporting year exceeds 2 percent of the total retail price of electricity in that year. All of these uncertainties combine to make sREC values very difficult to forecast, so it must be emphasized that the value assumed for the sRECs is a rough estimate of the potential value and is far from guaranteed.
40. Daily, 2010
41. Wiser et al., 2009
42. Bolinger, 2009
43. Kollins, 2008
44. IREC, 2010b
45. Specifically, the IEEE 1547 and the National Electrical Code.
46. Kollins, 2008
47. In Texas, this has been an issue in municipal utility service territories.
48. Bolinger, 2009
49. Bolinger, 2009
50. IREC, 2009a
51. IREC, 2009a
52. Livingston, 2009
53. New Jersey Board of Public Utilities, 2008
54. New Jersey Office of Clean Energy, 2010
55. DSIRE, 2010a
56. PSEG, 2010
57. Wiser et al., 2009. The difference between small systems (<2 kW) and medium-large systems (>500 kW) was more than $2 per watt installed.
58. U.S. DOE, 2006. The equivalent progress ratio for panels is slightly lower at 81 percent. Data were only through 2005, however; both silicon and thin-film technologies have further reduced in cost since then.
59. This statement refers to competitiveness with today's power prices although the authors note the likelihood that prices increase in the future.
60. U.S. DOE, 2006 and Keyes et al., 2008.
61. Chu, 2010
62. Zwiebel, 2010
63. Chu, 2010. Sullivan, 2009. PV World, 2010.
64. EIA, 2009. Refers to retail sales of electricity only.
65. IREC, 2009a
66. Wiser et al., 2009
67. NREL, 2010a
68. DSIRE, 2010b
69. Flett Exchange, 2010
70. DSIRE, 2010d

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