On the Path to SunShot: Emerging Issues and Challenges in Integrating High Levels of Solar into the Electrical Generation and Transmission System

Paul Denholm, Kara Clark, and Matt O’Connell
National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.
2 Challenges of Economic PV Grid Integration and the Need for Flexibility

Solar-generated electricity, particularly from PV, has a number of characteristics that present challenges to cost-effective grid integration. Table 1 summarizes three key characteristics of PV generation, including variability, uncertainty, and non-synchronous generation. Each of these characteristics produces an economic challenge to PV integration—reducing the energy value (such as the ability to avoid fossil fuel use) and capacity value (the ability to replace conventional capacity) of PV. Note that CSP, particularly when deployed with thermal energy storage (TES), does not present the same challenges. The potential opportunities for CSP to increase overall solar penetration are discussed in Section 4.

Table 1. Characteristics of PV Electricity Generation and Associated Integration Challenges

<table>
<thead>
<tr>
<th>Solar Characteristic</th>
<th>Potential Economic Challenge to Integration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Energy Value &amp; Curtailment</td>
</tr>
<tr>
<td></td>
<td>Capacity Value</td>
</tr>
<tr>
<td>Variability</td>
<td>Supply/demand mismatch coupled with generator inflexibility leads to curtailment.</td>
</tr>
<tr>
<td></td>
<td>PV may not be able to replace conventional capacity during periods of peak demand.</td>
</tr>
<tr>
<td>Uncertainty</td>
<td>Part-load operation of thermal plants for operating reserves leads to curtailment.</td>
</tr>
<tr>
<td></td>
<td>Capacity needed for provision of operating reserves.</td>
</tr>
<tr>
<td>Non-synchronous generation</td>
<td>Part-load operation of thermal plants for provision of frequency response leads to curtailment.</td>
</tr>
<tr>
<td></td>
<td>Capacity needed for provision of frequency response.</td>
</tr>
</tbody>
</table>

The following subsections discuss each of the two economic challenges to PV deployment identified in Table 1, including the origin of the economic challenge and how the challenge is related to grid flexibility (the ability of system operators to respond to increased variability and uncertainty). Finally, each subsection provides an example of how PV’s benefits can decline in an inflexible grid.

2.1 Energy Value, Grid Flexibility, and the Challenge of Curtailment

This subsection discusses the ability of PV to provide energy and replace fossil fuel generation. As described in Table 1, PV’s generating characteristics present challenges to realizing PV’s full energy value. With high penetrations of VG resources, and without measures to enhance grid flexibility, not all of the electricity generated by PV can serve demand. As a result, some PV electricity must be curtailed, forcing the overall levelized cost of energy (LCOE) of PV resources to rise. Below, Section 2.1.1 describes how power system operators use different sources of grid flexibility to balance supply and demand. Section 2.1.2 discusses the potential limits to these sources of flexibility associated with high-penetration PV in a power system, and how these

---

4 Non-synchronous generation means that PV does not generate electricity via a large rotating turbine. The implications of this, as well as an introduction to frequency stability are discussed in more detail in Section 3.3 and the Appendix.
limits can result in curtailment. Section 2.1.3 models PV generation and curtailment in a system with limited grid flexibility. This information provides context for the presentation of options for maintaining PV’s energy value in Sections 3 and 4.

### 2.1.1 Types of Grid Flexibility

Power system operators maintain a reliable grid by constantly balancing consumer demand for energy with generation from a variety of resources. The ability of a power system to accommodate the changes in electricity demand is often expressed in terms of its “flexibility.” While there is no uniform definition of grid flexibility, it generally refers to the ability of the grid and generation fleet to balance supply and demand over multiple time scales, which becomes particularly important with increased variability and uncertainty of net load (Ela et al. 2014). Table 2 summarizes four categories of grid flexibility, which are described briefly below and discussed in Section 3.

<table>
<thead>
<tr>
<th>Type</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator flexibility</td>
<td>Ability of conventional generation to vary output over various time scales</td>
</tr>
<tr>
<td>Storage flexibility</td>
<td>Ability to store energy during periods of low demand and release that energy during periods of high demand</td>
</tr>
<tr>
<td>Geographic flexibility</td>
<td>Ability to use transmission to share energy and capacity across multiple regions</td>
</tr>
<tr>
<td>Load flexibility</td>
<td>Ability to vary electricity demand in response to grid conditions</td>
</tr>
</tbody>
</table>

Generator flexibility reflects the ability of conventional power plants to vary output to serve variations in electricity demand. The ability of generators to vary output is based on a host of technical, economic, and institutional factors. Most thermal plants have a maximum ramp rate (ability to rapidly change output) and ramp range (minimum and maximum output). The ramp range is limited by the plant’s minimum stable operating point, below which the plant cannot run. Because certain plant types cannot be started and stopped quickly, they are forced to remain online and operating above this minimum generation level. Finally, there are also minimum generation constraints due to the need to provide online (spinning) capacity for addressing uncertainty over multiple time frames. This includes operating reserves needed to maintain frequency stability—that is, the ability of the power system to remain operational after large, sudden mismatches between generation and load. A primer on frequency stability is provided in the appendix, while additional discussion of operating reserves is provided in Section 3.3. These services are typically provided by partially loaded thermal and hydroelectric units. The energy generated by these units when providing operating reserves represents energy that cannot be provided by PV.

Storage flexibility represents the ability to store energy during periods of low demand, and releasing this storage energy at a later time. In this manner, storage changes both the load (providing load flexibility) and acts as a generator (providing generator flexibility).
Geographic flexibility reflects the ability to share energy and capacity across regions, which requires both transmission capacity and institutions that allow this transfer. Institutions include markets or some other mechanism to buy and sell energy.

Finally, load flexibility reflects the ability to change the demand for electricity in response to grid conditions. This includes a variety of market mechanisms to incentivize consumers to use electricity when it is cheapest. These mechanisms are detailed in Section 3.

Combined, these four grid flexibility options are used by system operators to balance the supply of generation with demand.

### 2.1.2 Impacts of PV on Net Load and the Problem of Overgeneration

One challenge to realizing the full energy value of PV is accommodating the change in net load (normal load minus generation from VG solar\(^5\) and wind) associated with high midday PV generation and low electricity demand. This situation can create “overgeneration” conditions, during which conventional dispatchable resources cannot be backed down further to accommodate the supply of VG, and the supply of power could exceed demand (Youngein and Martinot 2015). Without intervention, generators and certain motors connected to the grid would increase rotational speed, which can cause damage. To avoid overgeneration, system operators may curtail wind or PV output. PV generation is curtailed by either reducing output from the inverter or disconnecting the plant. This requires that a plant or system operator have physical control of the generation resource, which is typical for large renewable power plants but uncommon for smaller systems, particularly distributed or rooftop PV systems. Curtailment has the undesirable trait of reducing the economic and environmental benefits of VG. Each unit of VG energy curtailed represents a unit not sold to the grid and a unit of fossil fuel energy not avoided. As the amount of curtailment increases, the overall benefits of additional PV may drop to the point where additional installations are not worth the cost (Cochran et al. 2015).

The change in net load shape and associated challenge of grid operation were highlighted in 2013, when the California Independent System Operator (CAISO) published a “duck chart” showing the potential for overgeneration at relatively high PV penetration, especially considering the host of technical and institutional constraints on power system operation (CAISO 2013).\(^6\) Although California likely will be the first place in the continental United States that must address the challenges of operating a large grid with high PV deployment, these issues will arise elsewhere as PV becomes more cost competitive in locations with lower-quality solar resources.\(^7\) Identifying and addressing the challenges illustrated in the duck chart in a region such as California will provide examples for other regions as PV becomes more cost competitive in locations with lower quality solar resources.

---

\(^5\) VG solar includes PV and CSP without TES.

\(^6\) The name is derived from the chart’s resemblance to the profile of a duck. Details on the modeling that led to creation of the duck chart are in CAISO studies (CAISO 2010, 2011a, 2011b; Liu 2014a, 2014b, 2014c).

\(^7\) Smaller grids, such as those in Hawaii have seen significant penetration of PV (Schuerger et al. 2013) as have other regions of the world such as Germany (Stetz et al. 2015). Many of the flexibility options discussed in this document are being deployed in those regions to successfully integrate PV.
Figure 1 shows the duck chart, in which each line represents the net load. Note that this chart represents only the part of California grid operated by the CAISO, which represents about 80% of the total state demand. The “belly” of the duck represents the period of lowest net load, when PV generation is at a maximum. The belly grows as PV installations increase between 2012 and 2020. As a result, it may become increasingly challenging to have sufficient capacity online to meet the increased ramp rate of net load that occurs when PV output drops in the evenings. In the 2020 projection, starting at about 9 am, the system operator must be able to reduce generator output from about 20,000 MW to 12,000 MW by turning generators down or off. However, the operator must also be able to ramp back up to the peak demand of about 26,000 MW occurring at 8 pm. The operator may not be able to back down sufficient generation, which would force PV curtailment. Addressing this issue requires increased grid flexibility.

In addition to technical challenges of meeting increased variability, additional factors that limit generator flexibility include contractual and institutional restrictions on plant operation, including long-term “must take” contracts, self-scheduling, and combined heat and power plants (Youngein and Martinot 2015). These constraints also apply to imports of out-of-state generation, which may have established contracts and restrictions on flexible operation (Lew et al. 2015).

Examining the relationship between system flexibility and curtailment can help determine the potential of PV to economically supply substantial amounts of energy to a power system.

---

8 For more details about CAISO, see http://www.caiso.com/Pages/default.aspx.
2.1.3 Modeling PV Generation and Curtailment with Limited Grid Flexibility

This subsection demonstrates the impact of limited grid flexibility on curtailment and the economics of PV energy in a SunShot future. We start by generating scenarios of increased solar penetration, and then we examine the resulting impacts on system operation and corresponding curtailment.

Figure 2 shows normal load and net load with wind and solar (combined PV and CSP) profiles in California. The scenario assumes a fixed amount of wind with the potential to meet 11% of the state’s annual demand. Three potential penetration levels of solar are also included: zero, 7.5%, and 11%. Each case assumes 1.5% of total demand from CSP, with the remainder derived from PV. The vast majority of the CSP does not have thermal storage, so it produces output profiles similar to those from PV. The renewable generation profiles were derived from those developed for the Western Wind and Solar Integration Study (WWSIS) (GE Energy 2010) and refined for phase 2 of that study (Lew et al. 2013).

Figure 2 shows the profiles for March 29, which is the day in California with the lowest net load and likely the most challenges for PV integration and possible overgeneration. Because of the relatively low load, the potential proportion of generation from wind and solar on this day is higher than average—about 16% from wind and 0%, 12.5%, and 18% from solar in the three solar cases. The figure also shows very low net loads that would need to be met by the remaining generation fleet, assuming all solar generation could be used. In this example, the new minimum net load point (as low as about 7,700 MW in the 11% solar case) is shifted from 4 am to noon.

---

9 This represents a relatively small increase in wind generation. In 2014, California generated 12.7 TWh from wind in-state and imported another 12.7 TWh of wind for a total of 25.4 TWh, which provides about 8.6% of the total demand (296.6 TWh).

10 Penetration of utility-scale solar in 2014 was about 4.2%, or about 6% including rooftop solar (CEC 2014). Based on recent projections, 11% solar penetration could be achieved as early as the end of 2017 (GTM & SEIA 2015).

11 Versions of several figures provided in this work have been previously presented in Denholm et al. (2015).
The net load shown in Figure 2 does not consider the constraints that actually occur in operating the system. To examine the impact of PV on system operation, we simulate the California grid using the PLEXOS production-cost model. Note that our analysis considers the entire state of California, including the service territories of all investor-owned and publicly owned utilities. The model simulates the operation of all power plants throughout the Western Interconnection. The data and assumptions are derived from a combination of the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) 2024 Common Case (WECC 2014) and the CAISO 2014 Long-Term Procurement Plan (LTPP) data set\(^\text{12}\) (CPUC 2013a), with significant modifications derived from Brinkman et al. (2016) and Denholm et al. (2015).

We generated two general scenarios. The first is a “limited flexibility” case that includes a set of restrictive assumptions about grid operations in California. Key assumptions in this limited flexibility case include the following:

- There are no net exports of electricity from California.\(^\text{13}\)
- No new DR or storage is installed beyond what is in service in 2015.\(^\text{14}\) While existing pumped storage (about 2,500 MW) is allowed to respond to net load, this simulation does not

\(^{12}\) Additional discussion of the California LTPP model can be found in Eichman et al. (2015).
\(^{13}\) This is based on the fact that California has historically been a net importer, and there are limited market mechanisms to allow California to sell excess renewable energy out of state. Further discussion is provided in Liu (2014a).
consider the 1,325 MW of additional storage that will be deployed as part of the California storage mandates; this is evaluated in later sections.

- Twenty-five percent of all generation within certain zones must be met with local fossil or hydro generation.\(^{15}\)
- Instantaneous penetration of VG (including PV, wind, and CSP without TES) is limited to 60% of the normal load.\(^{16}\)
- VG cannot be used to provide reserves.

Grid simulations were performed with these assumptions for a variety of penetrations of solar to calculate the amount of curtailed energy. In the case with 7.5% annual solar, the system is flexible enough to accommodate changes in the net load without the need for significant curtailment. However, in the 11% annual solar case, the system is unable to accommodate all solar generation. Figure 3 shows the simulated net load resulting from the 11% solar case for March 29. In this case, the actual net load met by conventional generation is not allowed to drop below about 12,600 MW. This represents a California system-wide minimum generation constraint, meaning online generators in California—and certain contracted generators outside California—cannot reduce output below this level, in order to satisfy operating reserves from conventional resources and other “traditional” system limitations.\(^{17}\) This minimum generation level is an important measure of the overall flexibility of the power grid.

---

14 Up to about 1.3% of peak demand (as much as about 900 MW during periods of peak demand) can be shifted via economic DR programs. This value is about equal to the existing “price response” DR available from the three investor-owned utilities in the CAISO territory (CPUC 2015).

15 In the database from which our analysis is derived (the Low Carbon Grid Study from Brinkman et al. 2016), the zones that require the 25% local generation limit account for 77% of all California load. The Diablo Canyon nuclear power plant does not contribute to the local generation requirement, which is a conservative assumption based on the fact that nuclear power plants typically do not vary load to provide operating reserves. For additional analysis of the impact of the local generation requirement, see Nelson (2014) and Brinkman et al. (2015).

16 This is based on the provision that renewables cannot provide reserves and the concern that, at 60% VG penetration without VG providing reserves, “the grid may not be able to prevent frequency decline following the loss of a large conventional generator or transmission asset” (CAISO 2013).

17 This minimum generation value is below a CAISO-only estimate of the lowest net load point of about 15,000 MW in the current system (Bouillon 2014). The lower minimum generation point in this analysis results from several factors, including greater flexibility from customer-owned cogeneration and eliminating certain fixed-schedule contractual limitations on plant dispatch. We assume this flexibility will occur to avoid negative prices that may occur in the CAISO market under overgeneration conditions. Also, Diablo Canyon unit 2 was out for maintenance on this day in the simulation, which removed 1,122 MW of non-dispatchable capacity. The net load in the system is less than 15,000 MW during only 34 hours of the year in this simulation.
These constraints result in the curtailed energy illustrated in Figure 4, which includes the combined solar potential, the amount of solar actually used by the system, and the curtailed solar. Overall, about 4% of the potential solar energy on this day is curtailed. However, during most days, there is little or no curtailment; over the entire year, only about 0.4% of potential solar generation is curtailed.
Without flexibility changes that allow conventional generation to reduce output, only a relatively small amount of additional PV generation can be accommodated on March 29. As more PV is added, there will also be a greater number of days with PV curtailment. Figure 5 shows the fraction of daily solar energy curtailed for each day of the year for the 11% annual solar potential case (blue) as well as a 15% annual solar potential case (red). Note that we add only PV in these cases; the impact of adding CSP/TES is discussed in Section 4. In the 11% solar potential case, solar energy is curtailed due to system flexibility limits on a total of 57 days, and on 49 of those days the amount of solar curtailed is less than 5% of potential generation. Moving to the 15% solar case increases the number of days of curtailed solar to 139, and on 16 days greater than 10% of solar potential is curtailed.

![Fraction of Daily Solar Energy Curtailed](image)

**Figure 5.** Fraction of daily solar energy potential curtailed in a scenario with 11% and 15% annual solar considering operational constraints in a system with limited grid flexibility

On an annual basis, increasing the annual solar potential from 11% to 15% increases the total curtailment from 0.4% to 1.6% of potential solar generation. However, marginal curtailment—that is, the curtailment of additional PV required to increase solar potential from one level to the next—increases at a greater rate. Increasing annual solar potential from 7.5% to 11% requires that only 1.2% of the added PV generation be curtailed. However, increasing annual solar potential from 11% to 15% requires that about 5.5% of the added PV generation be curtailed. This illustrates the diminishing returns that can result from adding PV to a system with limited grid flexibility, and it highlights the importance of analyzing total and marginal curtailment rates in such systems.
Figure 6 illustrates the total and marginal curtailment results from the addition of PV. The annual solar penetration is the fraction of total demand in California met by PV (plus the fixed amount of CSP), after removing curtailed solar energy.\textsuperscript{18} The points on the curve are the actual modeled scenarios.

![Graph showing annual solar curtailment and penetration](image)

**Figure 6. Annual marginal and total solar curtailment due to overgeneration under increasing penetration of PV in California in a system with limited grid flexibility**

The rapid increase in marginal PV curtailment rates as a function of solar penetration is a significant limitation to PV remaining competitive with other sources of low-carbon energy once solar achieves a certain penetration (in this case, perhaps 15\%–20\% of annual demand). For example, previous analysis demonstrated that additional wind often has a lower curtailment rate than PV at increasing penetration (Denholm and Hand 2011; E3 2014). This challenge can be observed by examining the impact of curtailment on PV’s LCOE. As curtailment increases and capacity factors decrease, the LCOE increases. This is illustrated in Figure 7, which provides PV LCOE as a function of solar penetration in the system without enhanced grid flexibility. In this figure, the PV cost is based on the SunShot utility-scale LCOE goal of 6 ¢/kWh, which largely depends on being able to use all the PV energy by minimizing curtailment.

\textsuperscript{18} Where the total demand is equal to the consumer demand plus storage losses associated with pumped hydro.
Figure 7 shows the importance of examining marginal curtailment rates. While average rates can remain relatively low, marginal rates determine the cost and value of adding the next unit of PV to the grid. There is no predefined “threshold” at which PV curtailment would prevent further deployment. However, as curtailment-related costs increase, additional units of PV become less competitive against additional units of other energy sources. Investment decisions may be driven by incremental costs and benefits, including the impact of curtailment. It is important to note that actual allocation of curtailment among different renewable generation sources (including existing or added generators) will be driven by various factors, including local grid conditions, underlying contractual agreements with suppliers, production tax credits, and other regulatory issues.

An alternative to measuring the impact of curtailment on PV LCOE (as shown in Figure 7) is to examine the value of PV in terms of avoided generation and how this value decreases as a function of penetration (Mills and Wiser 2012a. For example, at low penetration, each MWh of solar potential avoids 1 MWh of conventional generation and associated fuel and emissions. However, as curtailment increases, each MWh of solar potential avoids less than 1 MWh of conventional generation, thus decreasing its value. In systems with low flexibility, the avoided energy value of PV can drop rapidly, creating economic challenges for increased solar penetration (Mills and Wiser 2015).

Regardless of the performance metric used, the results in this subsection are similar to the results of previous analyses by a variety of groups studying the impact of flexibility options in the West. Analyses by Nelson and Wisland (2015), E3 (2014), and Brinkman et al. (2016) all demonstrate that, with limited flexibility, high solar penetration in California can result in very high curtailment rates.
The very high marginal PV curtailment rates observed in Figure 6 would likely limit contributions from solar without changing system operation to accommodate VG resources. However, the significant number of flexibility options discussed in Section 3 can both accommodate and change the net load shape to facilitate higher solar penetration.

### 2.2 Capacity Value—The Challenge of Meeting Peak Demand

Section 2.1 discussed the ability of PV to provide energy and replace fossil fuel generation. This subsection discusses the second challenge associated with achieving significant PV penetration—replacing capacity with PV and thus displacing both fossil fuels and the plants that burn them. This information provides context for the presentation of options for maintaining PV’s capacity value in Sections 3 and 4.

The capacity value (also called the capacity credit) of solar depends on the extent to which solar generation aligns with demand patterns. Solar energy provides capacity credit by reducing the demand that must be met by conventional generators during periods of high demand. Figure 8 shows normal load and net load for increasing levels of PV. The data are from the same studies discussed previously, but the solar profiles are scaled to provide potential annual PV penetrations from 0% to 14%. These 3 days include the day with the highest demand of the year.\(^\text{19}\)

---

\(^\text{19}\) This includes both the CAISO load and the load from the publicly owned utilities. For comparison, the non-coincident net peak demand from all utilities in California in 2014 was 62,454 MW (CEC 2015). The gross peak demand was 65,468 with 3,014 MW of self-generation, including 1,130 MW of PV. Because this is non-coincident demand, the coincident peak across the entire state would be lower.
Figure 8 illustrates how PV can reduce the net load by generating electricity during the hours of peak demand (typically 4 to 6 pm). This results in a capacity credit—the ability of PV to replace conventional generation. However, Figure 8 also shows how the capacity credit of PV can decrease as PV penetration increases. Figure 9 shows this effect in more detail by demonstrating how adding PV shifts the net load pattern and results in a declining incremental capacity credit. The top chart in Figure 9 zooms into the middle day of Figure 8, as indicated by the scale change, showing only the load between 6 am and 11 pm. The bottom chart of Figure 9 shows the PV output during this same period as a fraction of its annual peak. Without solar, the demand peaks at about 62,500 MW between 2 and 3 pm Pacific standard time (3 to 4 pm daylight savings time). There is significant solar generation during this time, with the entire PV fleet producing about 73% of peak output. (This output is the aggregated output of all PV throughout the state and PV imports dedicated to California). As PV is added, the net load shape shifts. When enough PV is added to meet 2% of California’s annual load (about 2,700 MWac), the demand between 2 and 3 pm has been reduced by about 1,990 MW, to 60,500 MW. However, the actual load peak has been shifted 2 hours later. PV output during this period is only generating at about 45% of rated output. This means the incremental capacity credit of PV on this day has dropped from about 73% (at zero penetration) to 45% (when PV is providing 2% of annual generation). As more PV is added, the peak is shifted later, and at 10% annual PV the net peak demand has been shifted to between 6 and 7 pm. The aggregated PV output during this hour is only 10% of peak output, meaning beyond this point PV has little ability to offset the need for conventional capacity on this day.

20 All data in the analysis have been shifted to standard time.
Capacity credits translate directly to the amount of conventional generation capacity avoided by PV. Figure 9 shows that, at low penetration, each 100 MWac of PV capacity installed on the system would reduce the need for conventional capacity by as much as about 73 MW on this day. However, as more PV is added, this number falls rapidly.

These figures provide a general overview of the drivers behind declining PV capacity credit, but they do not provide a detailed analysis of the resource adequacy impacts of PV. Utilities and system planners commonly use detailed reliability-based metrics to assess the capacity...
contribution of different resources. These methods use statistical approaches to determine the ability of a generation resource to maintain a reliable system and meet demand (NERC 2011; Madaeni et al. 2013a; Ibanez and Milligan 2014). These techniques are based on measuring the system loss of load probability (LOLP) with and without solar, and they examine how much additional load could be added with the addition of PV or CSP. This technique produces a capacity credit, expressed either in units of power (kW, MW) or as the annual fraction of the renewable generator’s nameplate capacity, that adds to system reliability by offsetting conventional capacity.21

A number of previous analyses calculate PV and CSP capacity credits, some of which are summarized by Mills and Wiser (2012b) in Figure 10. Despite the range of analytic methods and results, these studies follow the two general trends described above. First, at low penetration, PV’s capacity credit typically ranges from 50%–75% in the western United States.22 Second, PV’s capacity credit drops significantly as a function of penetration. Similar analysis shows that wind provides a much lower capacity credit at low penetration, but it does not fall as significantly as PV with increasing penetration (Mills and Wiser 2012a).

![Figure 10. Summary of PV capacity credit estimates](image)

Source: Mills and Wiser 2012b
Dashed lines indicate total capacity credit, while solid lines indicate marginal capacity credit.

---

21 This subsection provides a general discussion of capacity credit. Different regions of the country have adopted different methods to analyze capacity credit for the purposes of both reliability and compensation. For a California-specific example, see CPUC (2014b).

22 Relatively little analysis has been performed on the capacity credit of PV in the eastern United States, so it is unclear whether the trends observed in Figure 10 would be greatly different in that region.
Previous analysis also shows that, despite the reduced capacity credit due to increasing solar, the net peak period is narrower (i.e., encompasses fewer hours) with higher solar penetrations. This increases the possibility that, at high PV penetrations, new flexibility options could help maintain high capacity credit for PV. The variety of approaches discussed in Section 3 can be deployed, including DR (which can shift demand to periods of greater renewable output), short-duration energy storage, and alternative solar technologies such as CSP with TES (Madaeni et al. 2013b).