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Solar-to-Grid: Trends in System Impacts, Reliability, and Market Value in the United States

with Data Through 2019

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To download this report, a briefing deck, and underlying data visit the project page at https://emp.lbl.gov/renewable-grid-insights.

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Of course, any omissions or errors that remain are solely the responsibility of the authors.

Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

AC	alternating current
CAISO	California Independent System Operator
CCGT	combined-cycle natural gas turbine
CFD	contract for differences
CT	combustion turbine
DA	day-ahead
DART spread	spread between day-ahead and real-time market prices
DC	direct current
DPV	distributed photovoltaics
EIA	U.S. Energy Information Administration
ELCC	effective load-carrying capability
ERCOT	Electric Reliability Council of Texas
IREC	Interstate Renewable Energy Council
ISO	independent system operator
ISO-NE	New England Independent System Operator
LBNL	Lawrence Berkeley National Laboratory
MC	marginal cost
MISO	Midcontinent Independent System Operator
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NGST	natural gas steam turbine
NSRDB	National Solar Radiation Database
NYISO	New York Independent System Operator
PIR	Participating Intermittent Resource
PJM	PJM Interconnection
PPA	power purchase agreement
PV	photovoltaics
RGGI	Regional Greenhouse Gas Initiative
RTO	regional transmission organization
SAM	System Advisor Model
SPP	Southwest Power Pool
SRI	Severity Risk Index
UPV	Utility-scale photovoltaics

Executive Summary

With continued deployment of solar across the United States, assessing the interactions of solar with the power system is an increasingly important complement to studies tracking the cost and performance of solar plants. This report focuses on the historical contribution to reliability, trends in market value, and impacts on the bulk power system of solar deployed in the U.S. through the end of 2019.

The primary scope of this analysis includes the seven organized U.S. wholesale power markets and is based on historical hourly solar generation profiles for each individual plant larger than 1 MW or county-level aggregate profiles for smaller solar. In addition, we present a limited set of results for ten utilities that are outside of the independent system operator (ISO)/regional transmission organization (RTO) markets. Solar deployment in the California Independent System Operator (CAISO), where solar generation was equivalent to 18.7% of annual load in 2019, far exceeds the level in other ISOs. The New England Independent System Operator (ISO-NE) has the second-highest penetration, with solar generation equivalent to 4.3% of annual load in 2019.

The market value of solar is defined here as the sum of the energy and capacity values. It primarily varies across regions and years because of variations in average real-time energy prices and capacity market prices. The energy value, based on the hourly solar generation and real-time power prices at pricing nodes near each solar plant, is the largest component of the market value across ISOs (Figure ES-1). In 2019, the average energy value spanned from \$24/MWh in CAISO to \$60/MWh in ERCOT.

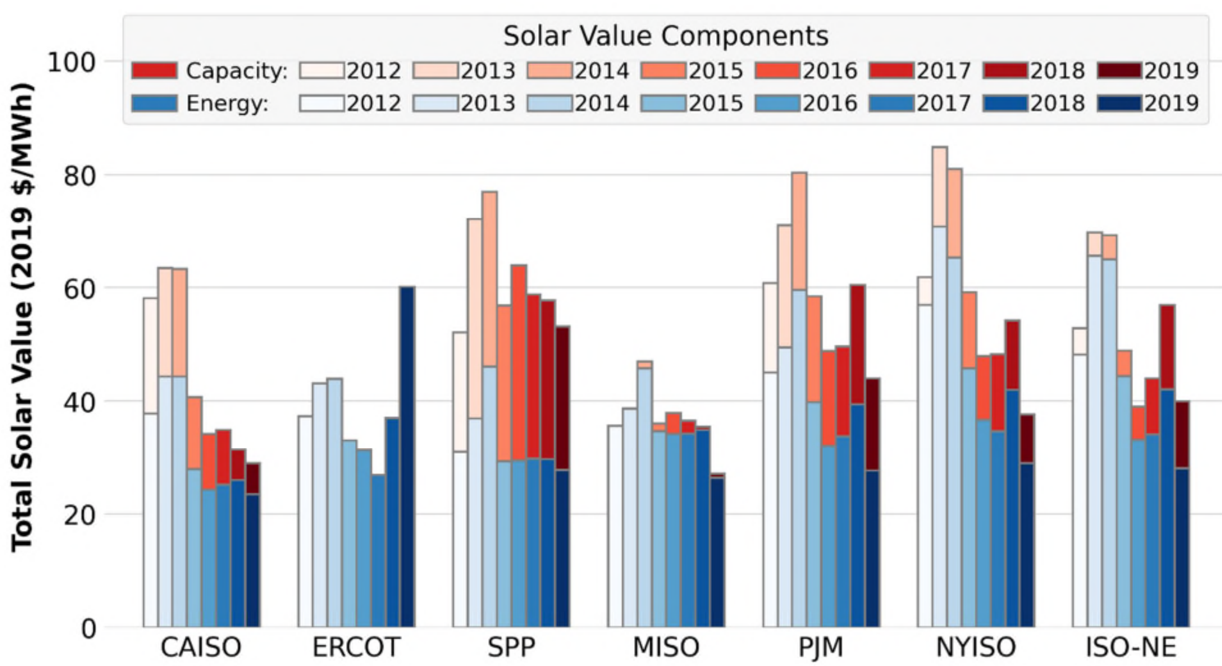


Figure ES-1. Combined Energy and Capacity Value of Solar Across ISOs

The capacity value of solar is based on the capacity credit of solar and the capacity price. Capacity prices vary considerably across ISOs and years. Capacity credits vary across ISOs but have been relatively stable over time, except in CAISO, where the capacity credit declined in 2018 and 2019. The capacity value in 2019 was highest in the Southwest Power Pool (SPP; $25/MWh), though capacity prices there are based on estimates of bilateral capacity transactions rather than transparent organized capacity market prices, and lowest in the Midcontinent Independent System Operator (MISO; below $1/MWh) where capacity prices are the lowest of all organized capacity market prices. No capacity value is shown for the Electric Reliability Council of Texas (ERCOT), because ERCOT does not have a capacity obligation nor a capacity market. ERCOT's market instead relies on the potential for high energy prices, as experienced in the summer of 2019, to ensure adequate resources.

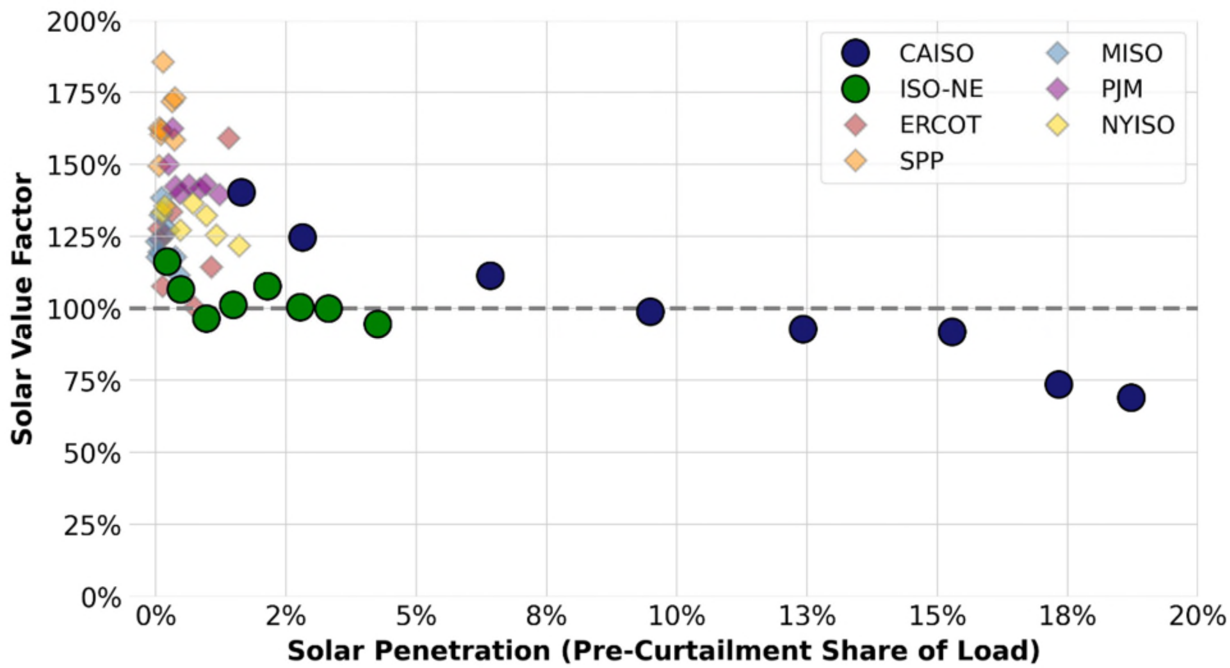


Figure ES-2. Solar Value Factor vs. Solar Penetration in Each ISO, 2012–2019

The market value of solar in CAISO declined between 2012 and 2019, both overall and relative to annual average energy and capacity prices. In 2012, solar's market value in CAISO was 40% higher than the value of a flat block of power (representing the market value of a generator that operates at full AC nameplate capacity in all hours of the year). By 2019, however, solar's value was 31% lower than a flat block of power's value. Figure ES-2 shows this trend based on the changes in solar value factor (which is calculated by dividing solar's value by a flat block of power's value) as CAISO's solar penetration increased over time. In CAISO, solar's relative market value declined because of a solar-induced shift in the timing of high and low energy prices and a reduction in solar's capacity credit. In contrast, the market values of solar in ERCOT, SPP, MISO, PJM Interconnection (PJM), and NYISO—where solar penetrations were low—did not decline relative to average prices. A slight decline in market value relative to average prices in ISO-NE reflects a combination of high winter natural gas prices (causing high winter electricity prices) in recent years and a slight shift in the timing of peak real-time prices toward early evening hours in the summer. The tendency for high value factors at low solar penetration that decline with solar penetrations above about 5% is similarly found in a select set of non-ISO utilities.

As solar's market value declined in CAISO, its cost—as measured by levelized power purchase agreement (PPA) prices—declined at a similar pace, thus maintaining solar's overall competitiveness (Figure ES-3). Solar was more competitive in PJM and the non-ISO utilities where the market value in 2019 exceeded the levelized PPA price of contracts signed in 2019. This suggests that an offtaker in these regions who purchased solar power through a PPA signed in 2019 paid less than they otherwise would have to purchase the same amount of energy (delivered at the same time and location as solar) and capacity from the spot wholesale market. Solar was especially competitive in ERCOT in 2019 as the energy value of solar rose significantly with a general increase in wholesale electricity prices.

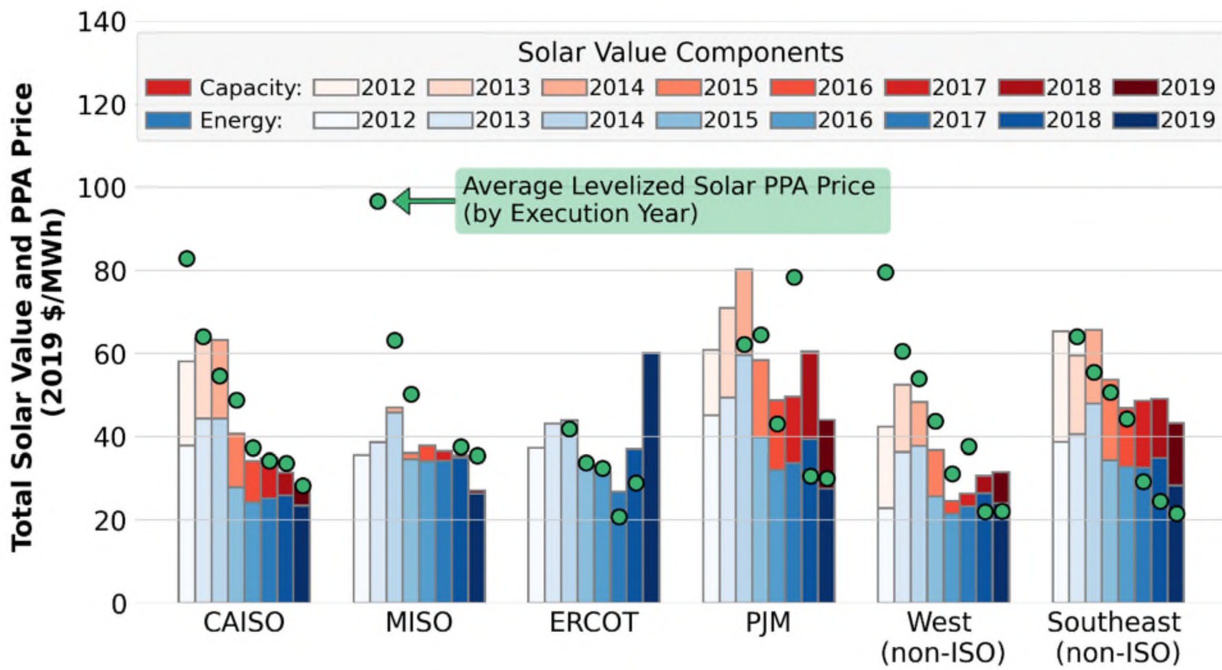


Figure ES-3. Solar Market Value Versus PPA Prices in Select Regions Over Time

Impacts of solar on the bulk power system are obvious in the CAISO system (Figure ES-4). The net load has shifted to resemble the "duck curve," with particularly low net load—defined as customer demand for electricity less wind and solar generation—during spring days and high ramps as the sun sets in the evening. Similar patterns emerge in real-time prices, with lower prices during the day and higher prices in the early evening. Ancillary service requirements, particularly regulation reserves, have increased during the day, as have regulation prices. Negative real-time prices during low net load days in the spring suggest growing challenges with reducing generation in response to lower net load levels.

However, broader shifts in the system—including growing participation of western utilities in the Western Energy Imbalance Market and variations in hydropower levels—appear to have mitigated some challenges in 2019 relative to 2017, even with greater solar deployment in 2019. Impacts to the net load shape from solar are similarly evident in a number of non-ISO utilities in the Western U.S.

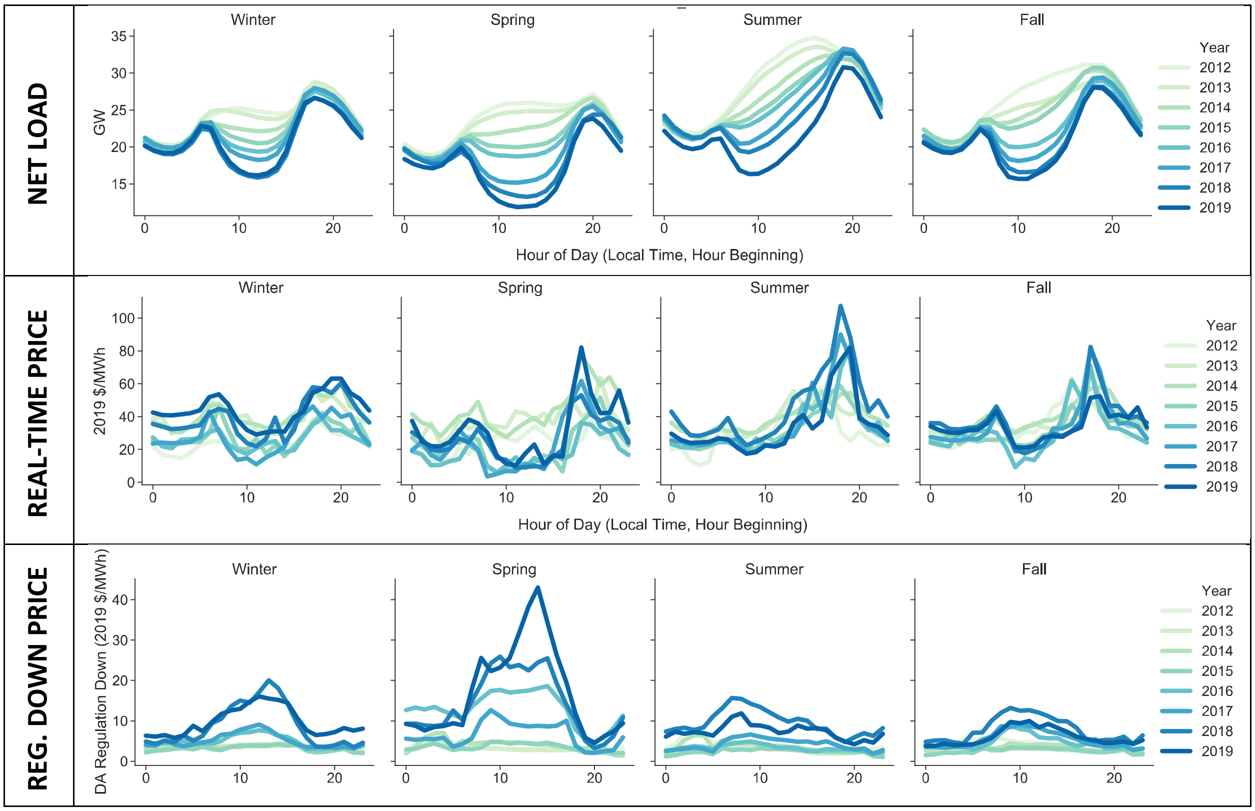


Figure ES-4. Seasonal Pattern of Net Load, Real-time Energy Price, and Day-Ahead (DA) Regulation-Down Price in CAISO

With much less solar deployment in the other ISOs, solar impacts on the bulk power system are much less obvious. In fact, at low penetrations, solar's impact on flexibility needs can be the opposite of what is observed at higher penetrations. With a high solar penetration, the net load ramp rates in CAISO exceed the net load ramp rate without solar by 30–54%. However, at low penetrations, the net load ramp rates can be lower than they would be without solar (Figure ES-5). In ISO-NE, for example, net load ramp rates in 2019 were 1%–5% lower than they would be without solar. Net load ramp rates for high solar penetration utilities in Arizona and Nevada exceeded the net load ramp rates without solar by 32% and 35%, respectively.

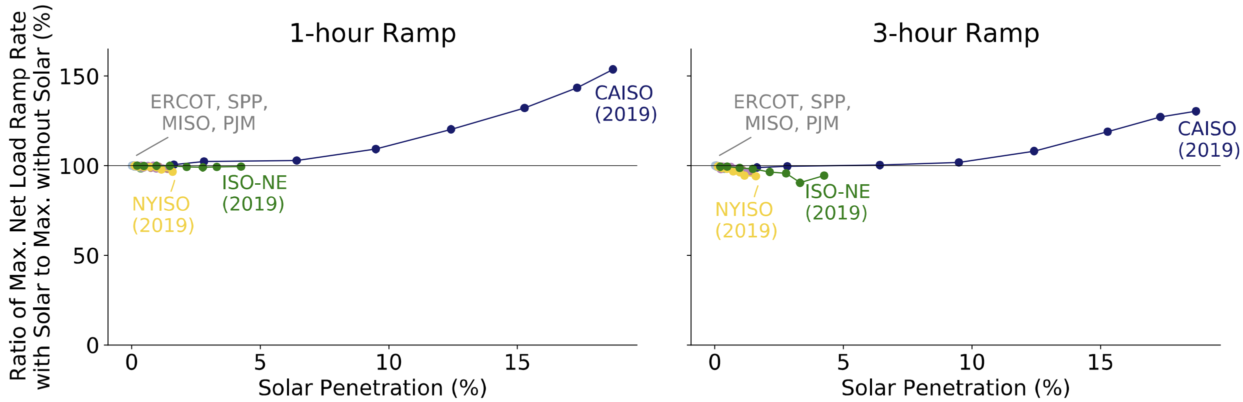


Figure ES-5. Impact of Solar on Maximum Net Load Ramp Rate

The CAISO evaluates its ability to meet the net load ramps by calculating NERC's Control Performance Standard 1 (CPS1) on an hourly basis. The CAISO has indicated that it is experiencing challenges in balancing supply and demand during sunrise and sunset because its CPS1 hourly performance tends to be less than 100% during these times. NERC balancing standards require CPS1 performance is greater or equal to 100% averaged over the previous 12 months. The CAISO is exploring several mitigating measures to address these challenges.

Additional proxy indicators, described in detail in the report, provide somewhat mixed signals regarding the challenges of meeting net load ramps in CAISO. On the one hand, the fraction of price spikes that occurred when net load ramps were greater because of solar grew from 8% in 2017 to 18% in 2019. On the other hand, the frequency of what CAISO calls "power balance constraint violations"—due to insufficient upward or downward ramping capability—has remained very low even with growing solar. In addition, the frequency of non-zero prices and the net payments for the flexible ramping product decreased between 2017 and 2019. These findings are complicated by the fact that prices do not fully account for all of the actions that system operators take to reliably balance supply and demand.

Nevertheless, changes in wholesale market prices for energy and ancillary services can change the incentives to invest in other resources, particularly flexible resources. The net revenues from energy and ancillary services of a representative combustion turbine (CT), reciprocating internal combustion engine (RICE), and a representative 4-hour battery storage system increased by more than 30% between 2012 and 2018 in CAISO (Figure ES-6). A large fraction of that change in net revenue was from increased ancillary service revenue, particularly for the battery. Net revenues declined again in 2019 in part due to lower natural gas prices. Price changes in other ISOs were not obviously tied to solar growth, though impacts may become more readily apparent with increased solar deployment.

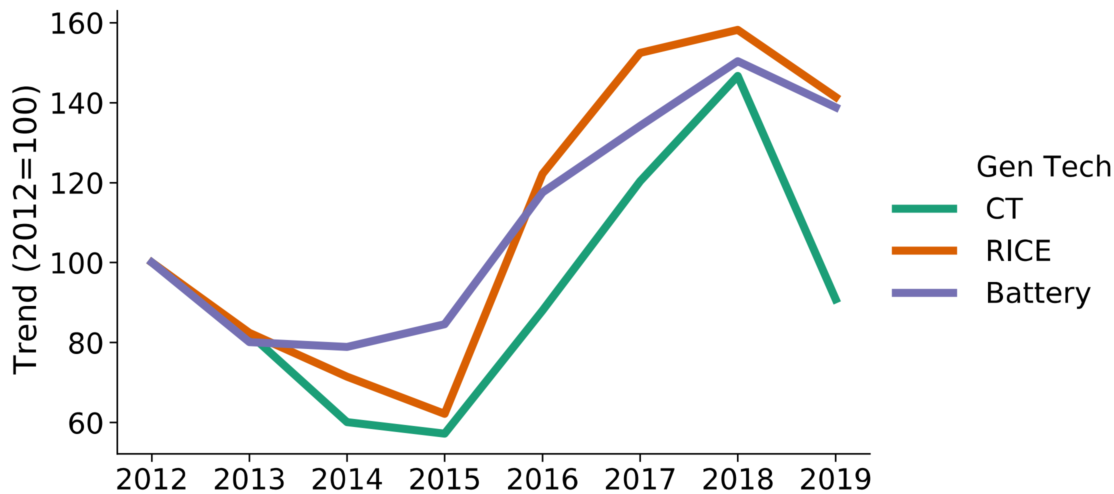


Figure ES-6. Net Revenues from Energy and Ancillary Service Markets for a CT, RICE, and 4-hour Battery in CAISO, Indexed to 2012

1. Introduction

Across the United States, solar deployment is increasing rapidly because of multiple factors, including favorable policy, rapid declines in cost, improvements in technology, and customer demand for clean energy. Some of these trends are tracked from an historical perspective in two Lawrence Berkeley National Laboratory (LBNL) reports focused on utility-scale solar and distributed photovoltaics (DPV) (Bolinger et al. 2020; Barbose and Darghouth 2019). This report complements those studies by assessing the interactions of solar with the power system. In particular, this report assesses the historical contribution to reliability, trends in market value, and impacts to the bulk power system of deployed solar in the United States.

Reliability, market value, and bulk system impacts are intertwined. Reliability is often considered to have two basic aspects, security and adequacy. Security "relates to the ability of the system to respond to disturbances arising within that system," whereas adequacy "relates to the existence of sufficient facilities within the system to satisfy the consumer load demand or system operational constraints" (Allan and Billinton 1988). In organized wholesale markets, wholesale energy and ancillary service prices are derived from security-constrained unit-commitment and economic dispatch. In effect, wholesale prices reflect the underlying cost of reliably balancing supply and demand at any point in time. In regions with a resource adequacy requirement, capacity prices reflect the underlying cost of ensuring that sufficient facilities will be available when needed. For organizational purposes, this report attempts to separately discuss reliability, market value, and bulk system impacts, though aspects of each are touched on throughout the report.

Though the focus is on the bulk power system and wholesale market value, the report considers the effect of both distributed and utility-scale solar. The geographic scope covers all seven of the organized wholesale market regions in the United States, including the California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), PJM Interconnection (PJM), New York Independent System Operator (NYISO), and New England Independent System Operator (ISO-NE). A more limited analysis is conducted for a select set of ten utility regions that are outside of the regions covered by independent system operators (ISOs)/regional transmission organizations (RTOs), particularly in the West and Southeast. The utilities were chosen both based on the amount of solar on their systems and to have broad geographic coverage. They include five in the West: Arizona Public Service (AZPS), Nevada Energy (NEVP), PacifiCorp-East (PACE), Public Service of New Mexico (PNM), Public Service of Colorado (PSCO) and five in the Southeast: Tennessee Valley Authority (TVA), Southern Company (SOCO), Duke Energy Carolinas (DUK), Duke Energy Progress East (CLPE), and Florida Power and Light (FPL). Analysis in the non-ISO regions is more limited because of the relative paucity of transparent wholesale market data in these areas where trading is bilateral rather than centralized.

As with LBNL's other two solar reports, the purpose of this analysis is to provide a credible, unbiased, comprehensive, and up-to-date source of information on the observed market value and grid impacts of solar. A comprehensive analysis of observed historical impacts can serve as a common foundation for anchoring discussions of future impacts and trends. In this way, observed historical impacts can help improve decision-making. In addition, by applying a common approach across multiple U.S. regions, decisions in one region can be informed by trends and impacts observed in other regions. Trends over time with increasing solar deployment can illustrate how market value and grid impacts evolve with increasing penetration. An historical assessment of trends can also provide a reference point for evaluating strategies to enhance value or mitigate adverse impacts. This report does not, however, evaluate specific strategies or make recommendations about strategies.

The analysis in this report builds on historical hourly solar generation profiles and observed wholesale market outcomes. Section 2 summarizes the historical deployment of solar by ISO. Section 3 captures a key component of the reliability contribution of solar as represented by the capacity credit, or the fraction of solar nameplate capacity that is counted toward resource adequacy targets. Section 4 uses the hourly generation profiles and capacity credit to calculate the market value of solar, considering energy and capacity value. Trends in the market value are compared to trends in the cost of solar to gauge movement in the overall cost-competitiveness of solar. Section 5 examines the impacts of solar on the bulk power system through observing trends in the net load—defined as customer demand for electricity net wind and solar—and in wholesale market prices. Finally, Section 6 provides an outlook for how factors driving the market value and impacts of solar on the grid may change in the near future. General overviews of methodological approaches are included throughout each section, with details available in the appendices.

Our work in this report builds upon, augments, and extends related efforts by others. There is growing recognition that levelized cost of electricity alone is not a useful metric for comparing technologies that provide different services to the grid. Instead, comparisons across technologies can account for both the cost of the technology and the value it provides to the grid (Joskow 2011; Borenstein 2012; Edenhofer et al. 2013; Hirth 2013; EIA 2017; Makovich and Richards 2017). Many studies have quantified the value of solar with increasing penetration levels (e.g., Lamont 2008; Mills and Wiser 2013; MIT 2015; Denholm et al. 2016), and, in select regions, these model-driven estimates have been complemented by empirical observations based on actual market outcomes with growing solar generation, including the U.S. (Bolinger, Seel, and Robson 2019; Brown and O'Sullivan 2020) and Germany (Hirth 2013). Related to the grid services provided by solar, entities responsible for the reliable operation of the grid are interested in better understanding the contribution of solar to reliability (Abdel-Karim et al. 2016). The impacts of solar on the dispatch of other generators and on wholesale prices, meanwhile, have been modeled with growing shares of solar (Mills and Wiser 2013; Lew et al. 2013; Deetjen et al. 2016; Brinkman et al. 2016; Bloom et al. 2016; Bistline 2017). As solar deployment increases, ISO market monitors and others are increasingly analyzing its impacts on actual markets (CAISO 2020; ISO-NE 2020; Bushnell and Novan 2018). Modeling studies have also shown that growing shares of solar can increase the value of flexible technologies, like storage or demand response (e.g., Mills and Wiser 2015; Denholm, Eichman, and Margolis 2017). This report complements these model-based studies by using empirical market data to show the real-world impacts of solar.

2. Solar Deployment and Generation

This section summarizes the deployed solar capacity by sector, solar generation by sector, solar curtailment, and overall market penetration of solar in each region. The data sources, methods used to derive hourly solar generation profiles, and validation of hourly profiles are described in Appendix A.

This report focuses on hourly solar generation within the boundaries of the seven organized U.S. wholesale markets and the ten non-ISO utilities mentioned in Section 1. It does not analyze solar projects operating in the remainder of the country. At the end of 2019, deployed solar capacity in the seven ISOs and the ten non-ISO utilities was 52.6 GW on an alternating current (AC) basis, or 87% of the national cumulative solar capacity.[1]

The universe of solar projects is based on individual projects larger than 1 MW_{AC} tracked in U.S. Energy Information Administration (EIA) Form 860 and aggregate capacity estimates of DPV from EIA Form 861. With these two data sources EIA tracks both in-front-of and behind-the-meter solar. In this report, utility-scale photovoltaics (UPV) refers to projects that are larger than 1 MW_{AC} and tracked in EIA Form 860, whereas DPV refers to DPV from EIA Form 861. This delineation of UPV and DPV differs from the various sectoral definitions used by individual ISOs. It also differs from the definition in LBNL's utility-scale solar report, where UPV is limited to ground-mounted projects that are larger than 5 MW_{AC}.

Solar nameplate capacity is unevenly distributed among the seven ISOs (Figure 1). CAISO had by far the most solar capacity in 2019, with more than 21 GW_{AC} (representing 54% of the installed capacity among all ISOs), followed by PJM with 6.7 GW_{AC}, ISO-NE (3.7 GW_{AC}), ERCOT (2.9 GW_{AC}), MISO (2.2 GW_{AC}), NYISO (1.9 GW_{AC}), and finally SPP (0.5 GW_{AC}). Relative to the annual peak load in each ISO (adjusted to account for our estimate of behind-the-meter DPV), CAISO's solar capacity penetration reached 43% in 2019, and ISO-NE's climbed to 15%, while PJM only reached 4% (owing to its large load), similar to NYISO (6%) and ERCOT (4%). Solar deployment has grown in each region, though at very different rates. CAISO, for example, added 2.2 GW_{AC} in 2019, while SPP added only 71 MW_{AC}. With CAISO's large base of deployed solar and continued growth, no other ISO region is on track to catch up to CAISO's deployment in the near future.

The sectoral breakdown of total deployed solar also varies by ISO (Figure 1). The majority (55%) of installed solar nameplate capacity across the seven ISOs was UPV in 2019.[2] In some regions, the share of UPV far exceeded this level. UPV projects constituted 80% of ERCOT's solar capacity in 2019, for example. On the other hand, UPV projects in NYISO made up far less capacity than the residential and non-residential (commercial, industrial, and other) DPV installations, with only 23%.

We synthesize hourly generation profiles of the installed solar capacity in each region. Initially each

[1] Our coverage by sector of either the cumulatively installed national DPV (residential and non-residential) or UPV capacity in the ISO territories and ten non-ISO utilities is similar, at 88% and 86% respectively.
[2] UPV primarily consists of PV projects, though a few concentrating solar power projects are included in CAISO.

individual plant (or aggregation of distributed PV at the county level) is simulated using historical weather data from the National Solar Radiation Database (NSRDB) in the National Renewable Energy Laboratory's System Advisor Model (SAM). The individual simulated plant profile is then "debiased" based on two sources of additional data (96% of all PV is debiased, the remainder lack the necessary additional data). One adjustment is to match the monthly reported plant generation in EIA-Form 923, the second is to match the aggregate UPV profile to the ISO- or utility-reported aggregate solar profile. Additional details for the debiasing technique are provided in Appendix A.

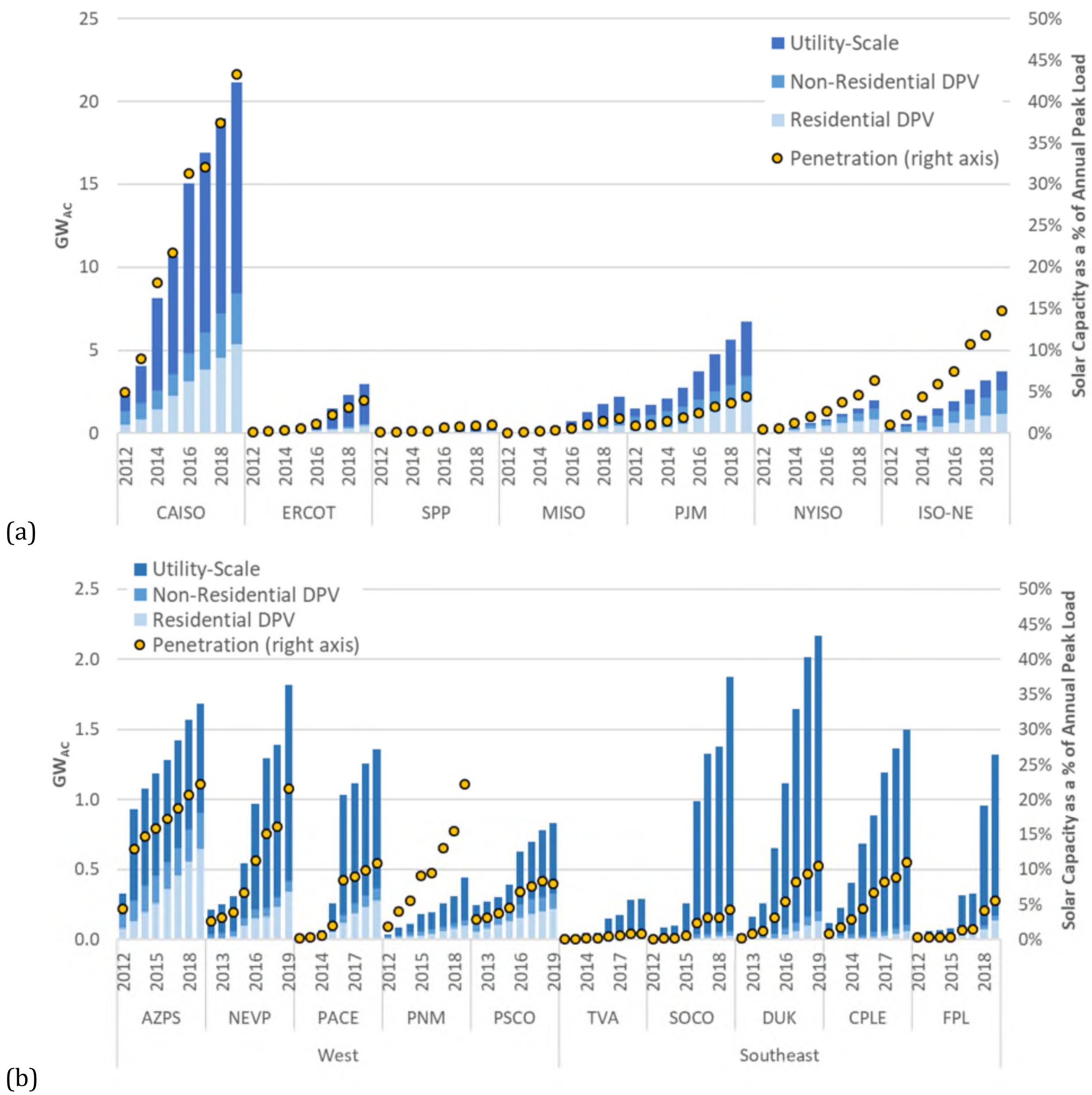
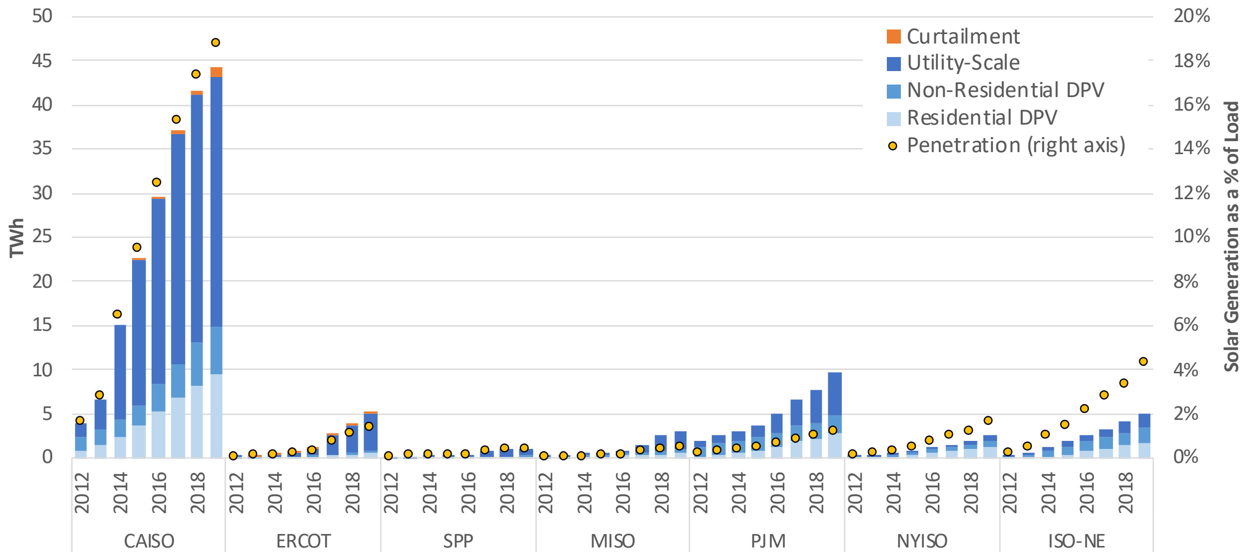
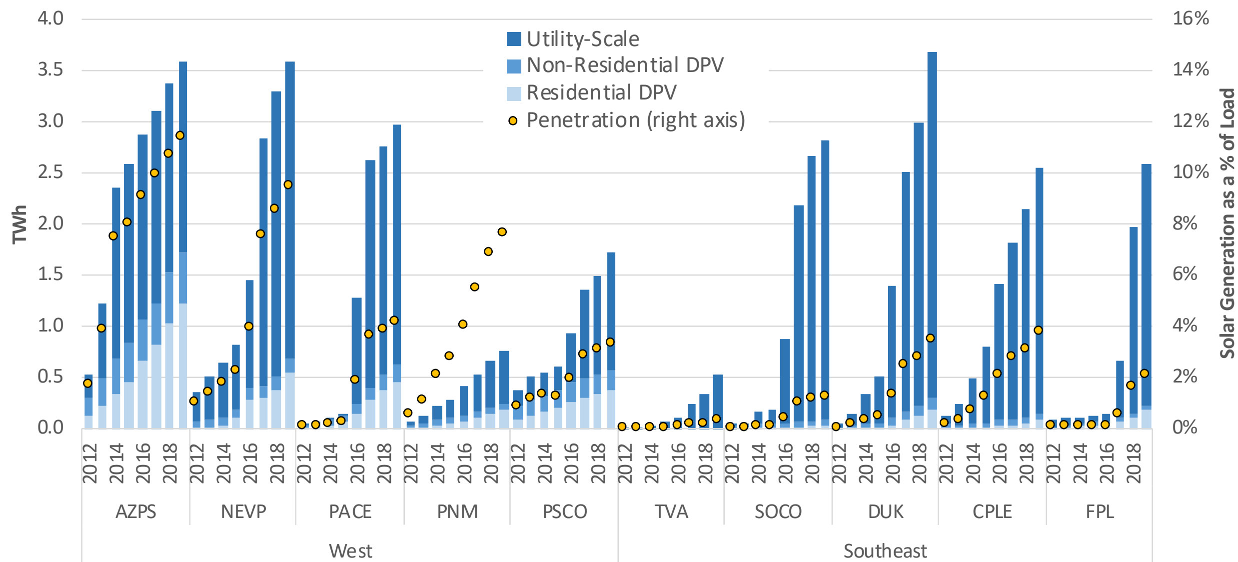


Figure 1. Solar Capacity Growth by Customer Segment Across (a) ISOs and (b) Select Set of Utilities in Non-ISO Regions



(a)



(b)

Figure 2. Solar Generation Growth by Customer Segment, Curtailment, and Penetration Across (a) ISOs and (b) Select Set of Utilities in Non-ISO Regions

The aggregate hourly generation profile is then converted to annual energy output for each segment in Figure 2. The relative distribution of solar generation among the ISOs is slightly different from the installed capacity distribution because of variations in solar resource quality across regions and project characteristics across sectors. Utility-scale installations, for instance, tend to produce more energy per unit of MW_{AC} capacity than residential installations, due to orientation optimized for the site, the use of trackers, and a typically greater MW_{DC} capacity of the solar array relative to the MW_{AC} capacity of the inverter (i.e., utility-scale installations have greater Direct Current (DC): Alternating Current (AC) or inverter loading ratios). Solar in CAISO makes up more of the energy generated across ISOs (66% in 2019) than the share of capacity (54%) owing to CAISO's relatively high resource quality and large share of utility-scale projects.

CAISO and ERCOT are the only two ISOs that report solar energy curtailment for utility-scale projects and no curtailment estimates are available for the ten non-ISO utilities. The dark-blue columns in Figure 2 for those two ISOs represent post-curtailment generation. Because other ISOs report wind curtailment, we assume that solar curtailment is not yet observed on a large scale in those other regions. As detailed in Section 4, 2.4% of all solar generation in CAISO and 5.0% of all solar generation in ERCOT were curtailed in 2019.

The golden circles in Figure 2 (right axis) compare the total solar generation (before curtailment) with the annual load in each ISO. CAISO again is highest, with solar energy across all sectors equal to 18.7% of the annual ISO load in 2019. The ranking of the other ISOs differs when presented in penetration terms compared to the ranking by capacity due to the relative size of the markets. Of the ISOs, ISO-NE has the second-highest penetration level in 2019 (4.3%). Solar penetration in all other ISOs was below 2%. Three of the utilities in the non-ISO region have solar penetration levels that exceed ISO-NE, but are still below the level in CAISO: AZPS (11.4%), NEVP (9.5%), and PNM (7.6%). Solar penetrations at PACE, PSCO, DUK and CPLE are similar to the ~4% solar penetration in ISO-NE, while the remaining utilities have less than 2% solar penetration. As described in Section 4, our analysis of market value highlights the difference in value contribution at high and low penetration levels. Furthermore, as discussed more in Section 5, regions with solar penetration greater than 4% see noticeable impacts on the bulk power system, while impacts in regions with lower penetration are small. Examining the current state of solar in these low-penetration regions is nevertheless useful, because it provides a reference against which future solar effects can be compared.

3. Capacity Credit of Solar

In all regions considered in this report, solar contributes to the overall resource adequacy of the power system. As described in the introduction, adequacy is one of the basic aspects of reliability, with the other being security. The fraction of the solar nameplate capacity that is counted toward resource adequacy is called the "capacity credit" of solar.

The capacity contribution of solar is used in different ways across ISO regions. In CAISO and SPP, for example, the capacity credit establishes how much solar can count toward meeting a load-serving entity's required planning reserve margin. On the other hand, the capacity credit of solar in ERCOT is used simply in advisory notices to the market to indicate expected overall system resource balances over the coming seasons. Load-serving entities in ERCOT are not required to meet a target planning reserve margin. In regions with organized wholesale capacity markets—including MISO, PJM, NYISO, and ISO-NE—the capacity credit of solar reflects how much of the solar capacity can qualify for participation in the capacity market auctions. The specific capacity accreditation rules vary across markets.

This section reviews the approaches used by different ISOs to calculate the capacity credit of solar and presents our estimate of the historical capacity credit based on the ISO rules. The capacity credit alone is of interest, because it reflects the resource adequacy contribution of solar, but it is also integral to estimating the historical capacity value of solar, as discussed in Section 4. The purpose of this section is to summarize the capacity credit based on the ISO rules and practices, not to validate or critique their respective approaches. Results in this report, based on current methodologies, can provide a benchmark for any future modifications. The approach and results for the capacity credit of solar in non-ISO utility regions is summarized in Text Box 1.

The methods used to calculate the capacity credit of solar vary by ISO (Table 1). For CAISO, the methodology recently shifted. Beginning in 2018, the capacity credit of solar in CAISO is based on the effective load-carrying capability (ELCC) method. In general, the ELCC is estimated using a probabilistic analysis of system reliability in which the capacity credit reflects how much load could be added after the solar resource is included in the system while maintaining reliability at the same level as prior to the addition of solar (Keane et al. 2011; Dent et al. 2016). Prior to the ELCC approach, the capacity credit in CAISO was based on an exceedance approach that considers the solar generation level that was expected to be exceeded a certain percentage of the time. In the other ISOs, the capacity credit is based on some variation of an exceedance approach or the generation of solar during some defined period. For example, the capacity credit of solar for the PJM capacity market is based on the average solar generation level during 2–6 pm from June to August, averaged over the preceding 3 years.[3]

Another important variation across ISOs is the seasonality of the capacity credit. At one extreme, PJM

[3] PJM proposed revisions to its tariff to adopt an ELCC method for assessing the reliability contribution of solar, wind, and other energy-limited resources effective June 2021 (PJM Interconnection 2020)

and MISO calculate a single capacity credit for the entire year based on solar generation in a peak summer window. NYISO, ISO-NE, and SPP define the capacity credit for both a summer and a winter season. ERCOT calculates the capacity credit for four seasons, and CAISO calculates it for each month.

Table 1. Variance in Solar Capacity Credit Rules by ISO

	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Basis of measurement	ELCC	Average generation in top 20 peak hours	Generation exceedance level during top 3% peak hours	Average generation during peak period	Average generation during peak period	Average generation during peak period	Median generation during peak period
Frequency of measurement	Monthly	Summer, fall, winter, spring	Summer, winter	Summer	Summer	Summer, winter	Summer, winter
Summer peak period	N/A	N/A	June–Sept	June–Aug 2–5 pm	June–Aug 2–6 pm	June–Aug 2–6 pm	June–Sept 1–6 pm
Winter peak period	N/A	N/A	Dec–Mar	N/A	N/A	Dec–Feb 4–8 pm	Oct–May 5–7 pm
Averaged over which years?	N/A	Rolling average over previous 3 years	All available years up to 10 previous years	Rolling average over previous 3 years	Rolling average over previous 3 years	Previous year	Rolling average over previous 5 years
Credit varies for UPV vs. DPV?	No	No	Yes	Yes	Yes	Yes	Yes

The capacity credits directly reported by the ISOs (in the case of CAISO and ERCOT) or calculated using individual hourly solar generation profiles and the ISO rules (remaining ISOs) are summarized in Figure 3. In the latter cases, we calculate capacity credits for each individual plant or county-level DPV profile. The line in the figure represents the capacity-weighted mean capacity credit and the shaded area represents the range for 95% of the plants. Capacity credits calculated using the hourly DPV profiles are reported separately from credits calculated with the UPV profiles.[4] For regions that define capacity credit by season or month, we show only the maximum capacity credit (occurring in the summer) and the minimum capacity credit (occurring in the winter). In regions with seasonal variation of the capacity credit, the winter capacity credit is nearly zero, because the peak winter periods often occur in the evening. A comparison of the capacity credit estimated using our hourly generation profiles to solar capacity credits reported in various ISO documents is summarized in Appendix B.

The capacity credit of solar across years has been mostly stable and greater than about 40% of the nameplate capacity in summer. CAISO's decreasing summer capacity credit over time is one exception,

[4] ISO-NE allows passive demand capacity resources, including behind-the-meter PV, to participate in the forward capacity market. The "on-peak" passive demand resource hours for calculating the capacity credit are similar to the hours listed in Table 1.

particularly with its change to the ELCC method in 2018. Whereas capacity credit based on average generation or an exceedance level in peak-period windows does not change with increasing solar penetration (absent an explicit change in peak-period definition and/or tying that period to net rather than gross load), the ELCC method results in a credit that can decline if increased solar penetration shifts the timing of system risk into non-solar hours (Munoz and Mills 2015; Helman 2017; Pickering et al. 2019). CAISO's declining capacity credit, therefore, reflects some combination of shifting to a more accurate calculation method and recognizing the shift in timing of high-risk hours into the early evening.

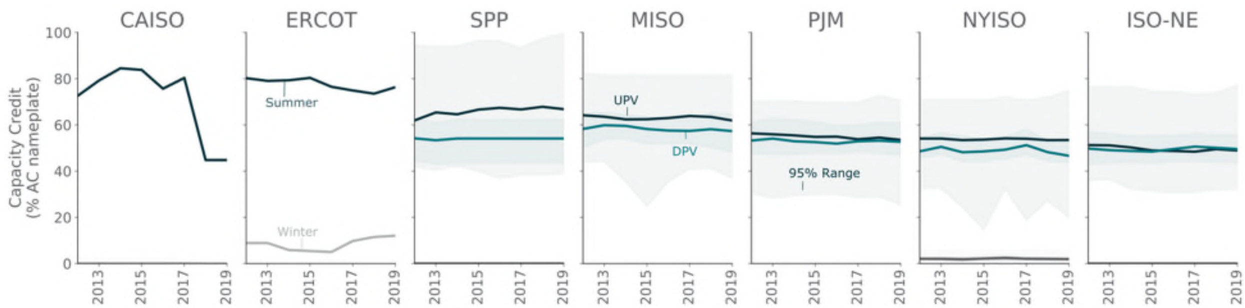
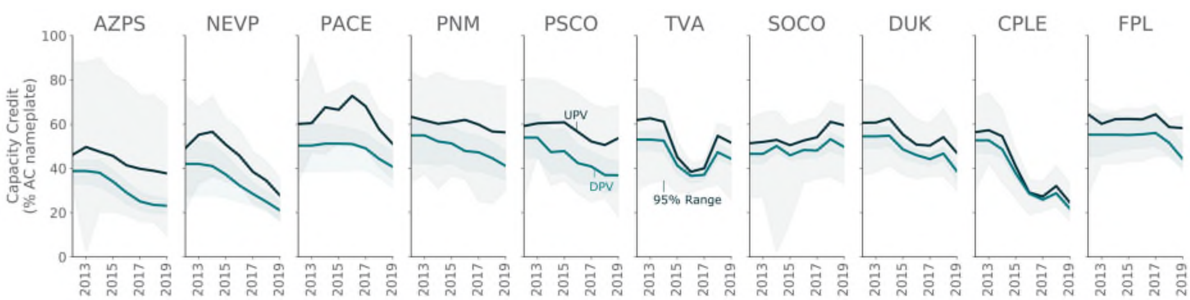


Figure 3. Capacity Credits of Solar for Each ISO

One important caveat related to solar's capacity contribution is that solar does not always interconnect to the system with the transmission capacity needed to deliver its generation fully to load during peak periods, and not all solar participates in wholesale capacity markets. The lack of full deliverability may be due to an economic tradeoff if transmission expansion is required for full delivery. As an alternative, a resource can interconnect as an "energy resource" without triggering as large of a need for transmission expansion. Such a resource would forgo participation in capacity markets, and its contribution from the capacity market perspective would be lower than reported here. Similarly, some resources may not participate in capacity markets for other reasons, and hence their realized capacity credits would be lower than the potential credits presented here.

Text Box 1. Capacity Credit Estimates for Non-ISO Utilities

Outside of ISO regions the capacity credit is often used as an input to planning studies, as input to economic evaluation of bids for long-term contracts, or as part of avoided cost calculations. Rather than investigate how each individual utility in the non-ISO regions calculates the capacity credit of solar, this analysis approximates the capacity credit using a uniform methodology. In particular, the capacity credit of solar in the non-ISO regions is the average solar production during the top 100 net load hours in the preceding three years. With growing shares of energy from solar, the peak net load hours shift from mid-afternoon in the summer into the early evening or to the winter. As a result, the capacity credit decreases with growing solar penetration across almost all of the utilities.



4. Market Value of Solar

This section analyzes the historical market value of solar generation within the seven organized wholesale power markets managed by ISOs across the United States. This section also uses a similar, though less granular, approach to estimate the value of solar generation for the ten non-ISO utilities. Details of the data and methods used to calculate market value in both organized wholesale markets and non-ISO utilities are included in Appendix C.

In a few cases, so-called “merchant” solar projects bid directly into the organized wholesale markets and earn the prevailing market price. In most other cases—for example, when a PPA is in place—the buyer will schedule the solar energy into the market, paying the solar project owner the pre-negotiated PPA price but earning revenue from the prevailing wholesale market price. A somewhat similar financial outcome can be achieved through a "contract for differences" (CFD), through which the solar plant and a CFD counterparty agree on a strike price. If the pre-negotiated strike price is above the prevailing price at which the solar plant sells its output into the market, the CFD counterparty pays the solar plant the difference. In the opposite case, when the strike price falls below the market price, the solar plant pays the CFD counterparty the difference. In all of these arrangements, the revenue earned from the sale of solar into wholesale markets reflects the market value of that generation from the perspective of the electricity system. Hence, the market value characterized in this section can be thought of as representing either the revenue earned by a merchant solar plant from selling power into organized ISO markets, or the avoided cost of a load-serving entity that purchases power from a solar project instead of the wholesale market.[5] The process followed here is also similar to the method used in New York to estimate the energy and capacity value components of the value of distributed energy resources (VDER) tariffs, which are used to compensate participating DPV resources directly (NYPSC 2019).

Our analysis focuses solely on the location-specific energy and capacity value of solar. In the organized wholesale markets, solar’s energy value represents the product of real-time wholesale market energy prices at the nearest node and the coincident solar generation. Solar’s capacity value represents solar’s contribution to meeting resource adequacy requirements, and it is determined by the capacity credit (described in Section 3) and the coincident capacity prices. Capacity prices have a zonal granularity in MISO, PJM, NYISO, and ISO-NE. The energy and capacity values both represent the *marginal* system

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[5] In the case of merchant solar projects (of which there are so far only a few), the link between wholesale market prices and value is direct, in that the former directly affects the latter through earned revenue. In the much more common case of solar projects with PPAs, the pre-negotiated PPA price establishes plant revenue and, depending on the specifics of the PPA, pricing may or may not be linked to wholesale market prices. Even if pricing is not directly linked to wholesale electricity prices, revenue earned by the sale of solar into the wholesale market still reflects the underlying market value of that solar—but, in this case, in the form of an avoided cost to the buyer. This is because the buyer could have, in theory, purchased power from the wholesale market instead of the solar project. Hence, the solar project’s estimated revenue, were it selling into the wholesale market, reflects costs avoided by the buyer under the solar PPA.

value of the last solar generator contributing to the market.[6] A similar approach is used to estimate market value in the non-ISO utilities. We use location-specific energy prices for utilities participating in the Western Energy Imbalance Market (EIM) or a single representative energy price for utilities not in the EIM. Solar's total market value is simply the sum of its energy and capacity values, expressed on a pre-curtailment basis.

The rest of this section proceeds by first describing trends in solar curtailment and then estimating solar's energy and capacity values. Next, we show how solar's market value has changed over time as solar market penetration has increased. We attribute value differences between solar generation and a "flat block of power" to differences in curtailment, location, and profile. Finally, we compare solar's market value to recent PPA prices.

4.1 Curtailment

Solar value calculations make use of post-curtailment (i.e., actual) generation to calculate market revenue, while the MWh of solar generation over which revenue or value is spread is based on pre-curtailment generation. Pre-curtailment generation reflects all potential generation—including curtailed generation—that theoretically could have contributed to generating that revenue. Said another way, a curtailed MWh is a MWh that *could have* displaced other generation and earned revenue from the sale of energy and/or capacity (and/or other services) if not for curtailment. The lost opportunity from curtailment negatively affects solar's value, presuming curtailment occurs in hours when energy prices are above $0/MWh.

Only two of the seven ISOs—CAISO and ERCOT—report curtailment of solar generation within their markets. Given that all seven ISOs report wind curtailment data,[7] we assume that solar curtailment is not yet occurring at significant levels among the five ISOs that do not report it (SPP, MISO, PJM, NYISO, and ISO-NE). Smaller residential or other DPV generators are not commonly curtailed. Curtailment in non-ISO utilities is difficult to track and thus largely ignored here, with the exception of AZPS. There, curtailment was largely driven by economic considerations when mid-day spring prices in the EIM turn negative, instead of local transmission constraints in Arizona. Curtailment in AZPS in 2018 was 0.5% of annual solar generation (O'Shaughnessy, Cruce, and Xu 2020).

Figure 4 shows that the annual solar curtailment rate in CAISO has been relatively modest, reaching just 2.4% of total solar generation in 2019 (or 3.6% of utility-scale solar generation).[8] While solar curtailment in CAISO increased only gradually between 2015 and 2018, 2019 saw a strong increase in

[6] The methods in this analysis inform questions about the marginal value of the next increment of solar. We compare this marginal value to the levelized price of PPA's signed in the same year. In contrast, recent EIA analysis posed a different question of how much revenue is collected by different generators for wholesale sales, inclusive of long-term contracts (EIA 2020b). Due to the differences in questions, the market value of solar calculated here is not comparable to the average U.S. wholesale price for electricity generated by solar calculated by EIA.

[7] Wind curtailment in 2019 ranged from 5.5% of wind in MISO to 0% of wind in PJM (Wiser et al. 2020).

[8] Though not shown in Figure 4, CAISO solar curtailment rose sharply yet again in the first 4 months of 2020, to 756 GWh—more than double the 396 GWh curtailed during the same months of 2019.

curtailment levels, especially in the second quarter. In 2019, CAISO attributed 2/3 of curtailment to local transmission constraints and 1/3 to system-wide oversupply. Solar curtailment in California shows a clear seasonal pattern, with peaks in the late spring (and to a lesser extent in the fall) when irradiance is above winter lows, load is modest, and hydropower generation is often strong owing to melting snowpack and spring runoff. These three factors were particularly pronounced in 2019, explaining the increase in economic curtailment of solar (CAISO 2020). The creation and expansion of the Western Energy Imbalance Market, which enables real-time bulk power trading throughout the West, has been credited with historically avoiding greater amounts of solar curtailment within the CAISO market (CAISO 2019b).

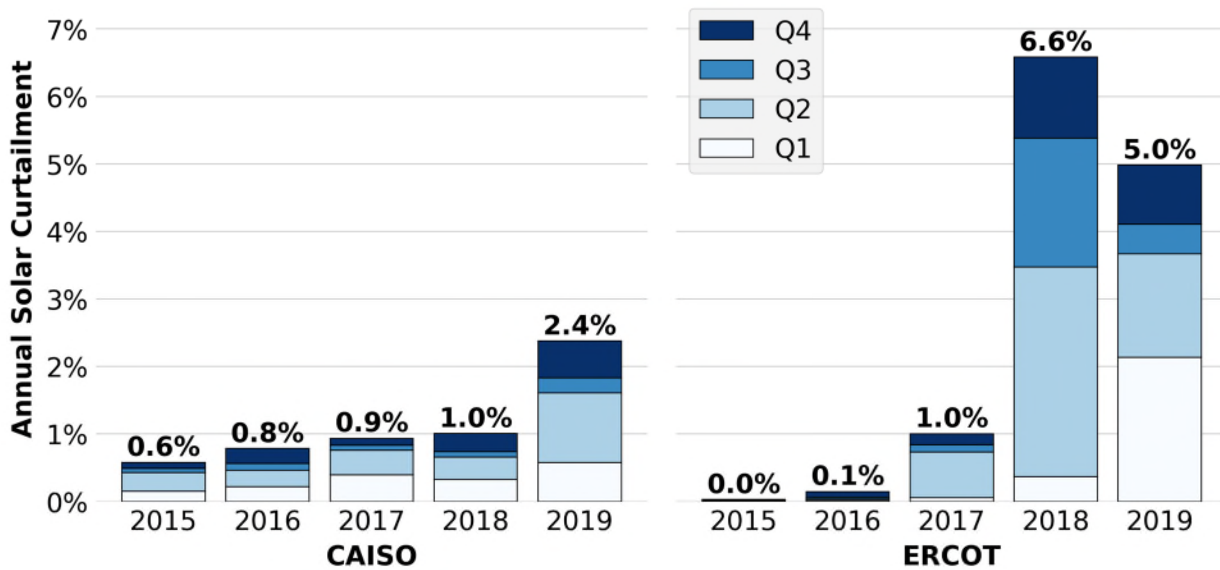


Figure 4. Annual and Quarterly Solar Curtailment in CAISO and ERCOT

In ERCOT, where solar is still a relatively new resource and solar penetration is only around 1%, there was almost no solar curtailment prior to 2017. However, ERCOT curtailed 1% in 2017, and that number shot up to 6.6% of total solar generation (or 7.7% of utility-scale solar generation) in 2018, well above ERCOT's 2018 wind curtailment rate of 2.5%, despite ERCOT's wind penetration being much higher than its solar penetration. Starting in the second quarter of 2019, absolute curtailment levels (and associated curtailment shares) declined, but annual relative curtailment was still twice as high as in CAISO. Most of the solar curtailment in 2018 and 2019 was concentrated among just a few projects located around Fort Stockton in West Texas that had curtailment levels up to 35% of their annual output. Local interconnection constraints for a single project were the largest source of curtailment in 2018. Resolution of those constraints through planned transmission upgrades (Rivera-Linares 2017), in part explains the decline in curtailment between 2018 and 2019. But the broader region still experienced severe transmission congestion in 2019, driven by strong load growth and low gas prices from oil and gas development in the Permian Basin (Potomac Economics 2020). Thus, the sharp rise in ERCOT's solar curtailment—which seems out of proportion to the level of solar penetration in Texas—has seemingly been driven by local congestion severely impacting just a few projects, rather than by broader system-wide conditions.[9] The large and approved West Texas Transmission Project intends mitigate the congestion by 2021 (AEP Transmission 2020).

If utility-scale projects were not curtailed as shown in Figure 4, UPV's energy value would have actually been lower by \$0.6/MWh in CAISO and \$1.1/MWh in ERCOT in 2019. This indicates that curtailment in both ISOs occurred predominantly during hours when local nodal electricity prices were negative.

4.2 Energy Value

Solar's energy value represents the product of real-time wholesale market energy prices and the coincident solar generation, and it reflects the degree to which solar output correlates with higher or lower energy prices over the course of a year. In calculating solar's energy value, we multiply plant-level (for utility-scale projects) or county-level (for distributed capacity) hourly solar generation by coincident hourly wholesale real-time energy prices from the nearest pricing node in each ISO. We focus on annual average values in this section even though solar's energy value can fluctuate considerably over the course of a year (peaking in the summer in most, but not all, ISOs).

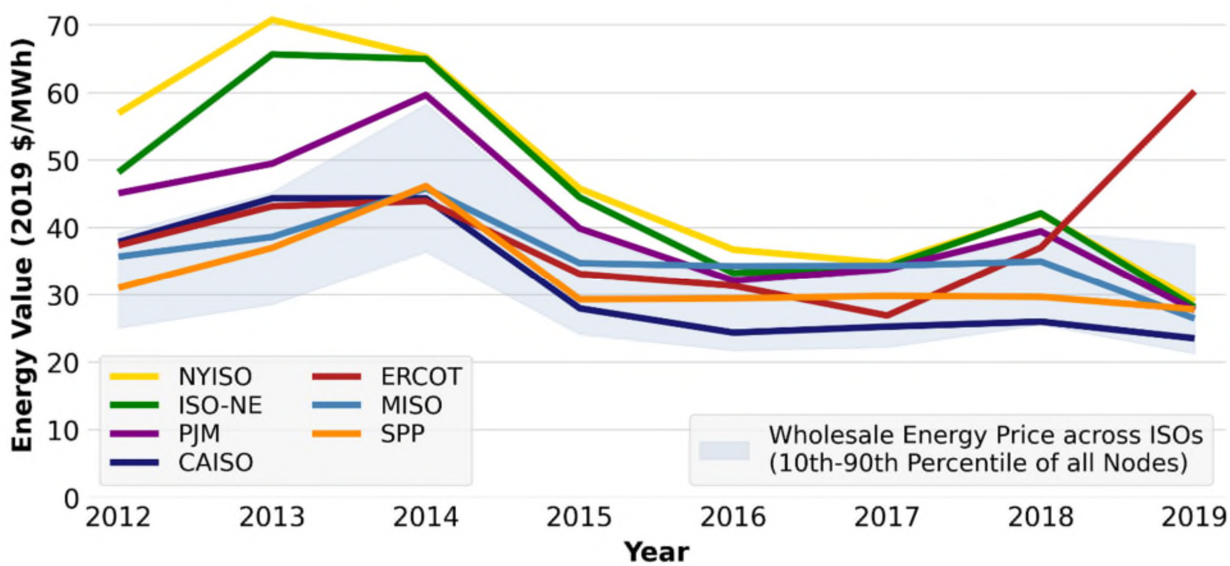


Figure 5. Annual Solar Energy Value Across ISOs with 10th -90th Percentile Range in Annual Average Energy Prices Across All Nodes

Figure 5 presents the (generation-weighted) average annual solar energy value in each ISO (colored lines) as well as the 10th to 90th percentile range of average annual wholesale energy prices across all nodes in the seven ISOs (blue-shaded area). From 2012 through 2019, the annual energy value of solar ranged from \$24/MWh to \$71/MWh and generally varied over time in concert with changes in annual

9 One potential reason for the congestion is an increase in local non-solar generation because of very low (and even negative) natural gas prices, which are related to increased local natural gas production and limited pipeline capacity (Collins and Adams-Heard 2019).

average wholesale energy prices (decreasing with falling electricity prices since 2014, though 2018 brought a moderate boost as electricity prices rose again). The main driver of changes in wholesale prices since 2014 was changes in natural gas prices, though secondary fundamental drivers—such as generation mix, other fuel price changes, demand growth, and even solar deployment—contributed to price changes (Mills et al. 2019). Wiser et al. (2017), for example, find that increased solar deployment decreased average annual wholesale prices by about $2/MWh in CAISO. In 2019, solar's energy value was lowest in CAISO ($24/MWh) and highest in ERCOT ($60/MWh), the latter being driven by high levels of scarcity pricing that boosted overall energy prices to their highest level since 2011 (Potomac Economics 2020).

4.3 Capacity Value

Solar's capacity value is dictated by two factors—its capacity credit (described in Section 3[10]) and prevailing capacity prices. Similar to the energy value calculations, in calculating the capacity value we use the prevailing capacity prices of the ISO zone in which the large-scale project or county (distributed PV) is located. Variations in capacity prices have been the primary driver of changes in solar's capacity value over time, given that solar's capacity credit has remained relatively stable across most years and ISOs. Exceptions can be found in CAISO, where the ELCC method resulted in strong capacity credit declines since 2018, and in several non-ISO areas such as NEVP, PACE, DUK, and CPLE. We do not show capacity values in ERCOT, because ERCOT has no capacity market or regulatory requirement to meet a specific planning reserve margin.[11]

In contrast to the energy value, capacity value can be harder for the owner or the purchaser of the power generated by solar (the solar offtaker) to monetize because of additional performance requirements or restrictions in capacity markets. For example, rules intended to limit the influence of subsidies motivated by state policy apply a "minimum offer rule" to resources which could, in turn, prevent solar resources from receiving capacity payments (Gheorghiu 2019b). Alternatively, solar and other variable resources may be unwilling to bear the performance risk associated with performance requirements, such as in PJM. These requirements may reduce participation in the capacity market or impact the risk-adjusted capacity value relative to the levels shown here. Storage or other flexible resources may also help manage performance risk. Nevertheless, we estimate the capacity value of solar and combine it with the energy value to estimate a total value.

To facilitate the comparison with solar's energy value, we denominate the capacity value in $/MWh terms by essentially spreading capacity revenue over annual, pre-curtailment generation. Solar's capacity value covers a broad range, both between regions ($1/MWh in MISO vs. $25/MWh in SPP in

[10] In CASIO, we apply the capacity credit for UPV reported in Section 3 to both UPV and DPV. In all other regions we use the DPV and UPV capacity credits.

[11] While CAISO and SPP also do not have organized capacity markets, their regulators still impose capacity obligations on load-serving entities that can be met via direct resource ownership or bilateral capacity contracts. Capacity value calculations in these regions are based on the bilateral capacity contract prices.

2019)[12] and over years within a region ($20/MWh in CAISO in 2013 vs. $5/MWh in 2019).

4.4 Combined Market Value

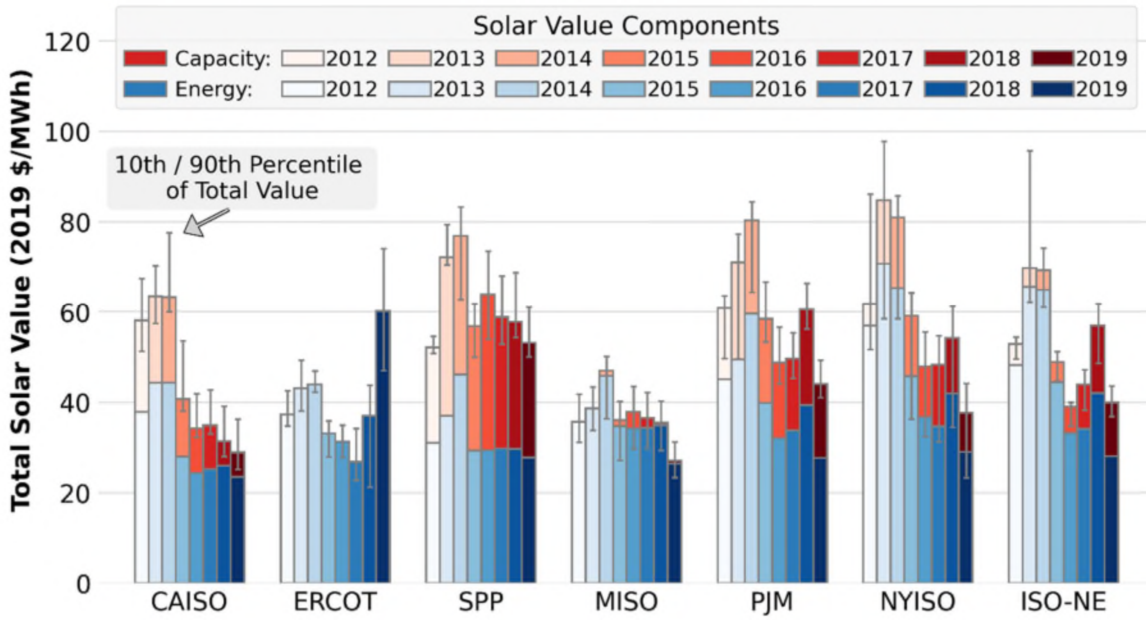
The combined market values depicted in Figure 6 are simply the sums of solar's energy and capacity values. In nearly all regions and years solar's energy value is larger than its capacity value, with the former often more than doubling the latter. Nevertheless, capacity value can contribute a sizable portion of solar's total value—e.g., around 50% in SPP in most years, and 30%-40% in PJM and ISO-NE in 2019. Notably, capacity value's contribution to total value is markedly higher for solar than it is for wind power, for which capacity value generally ranges from just $1–$5/MWh (Wiser and Bolinger 2020).

The combined energy and capacity values of solar ranged from $40–$80/MWh in most markets from 2012–2014, but declined thereafter owing to decreasing wholesale energy prices. In 2019, total market value ranged from the upper $20s/MWh in MISO and CAISO to $60/MWh in ERCOT.

Similar to the ISO regions, solar's average annual energy and capacity value declined in most non-ISO utilities following the overall drop in electricity prices since 2014 and ranged between $28/MWh in AZPS to $56/MWh in FPL in 2019. Because solar's energy value was relatively similar across utilities ($22–$30/MWh), the majority of the value spread can be attributed to wide ranges in solar's capacity value ($5–$30/MWh) which in turn were driven by variation in capacity credits (see Section 3) and a large span in capacity prices.

For ease of understanding, Figure 5 and Figure 6 depict the generation-weighted average value across all large-scale solar projects and distributed PV assets for each ISO and utility. Annual average solar values, however, vary based on project-specific generation profiles (influenced, for example, by local climates or technical characteristics such as use of single-axis trackers) and locational energy and capacity prices (reflecting transmission constraints). Figure 6 includes error bars that represent the 10th and 90th percentile of solar annual average values in each ISO or utility. Some markets showed very little variation in solar value in 2019 (ISO-NE and PJM had value ranges of about 20%) while others had large discrepancies (values varied by up to 60% in NYISO and MISO). Figure 7 summarizes both the variations in solar value for UPV and DPV in 2019 between regions (again, low in CAISO and MISO and high in SPP and FPL) and within regions (for example, western PJM has higher solar values than eastern PJM).

[12] To estimate solar's capacity value in SPP we use capacity transaction prices for bilateral contracts reported in FERC electronic quarterly reports (EQRs). Historically, few solar project owners may have bilateral capacity contracts, making it difficult for the project owner to monetize the capacity value of solar assessed in this analysis. In contrast to SPP, MISO has both bilateral capacity contracts and a centralized capacity market for residual capacity needs. In MISO, we only use the transparent capacity prices from the centralized capacity market rather than bilateral contracts. Solar's capacity value in MISO could be higher if we instead used bilateral capacity prices.



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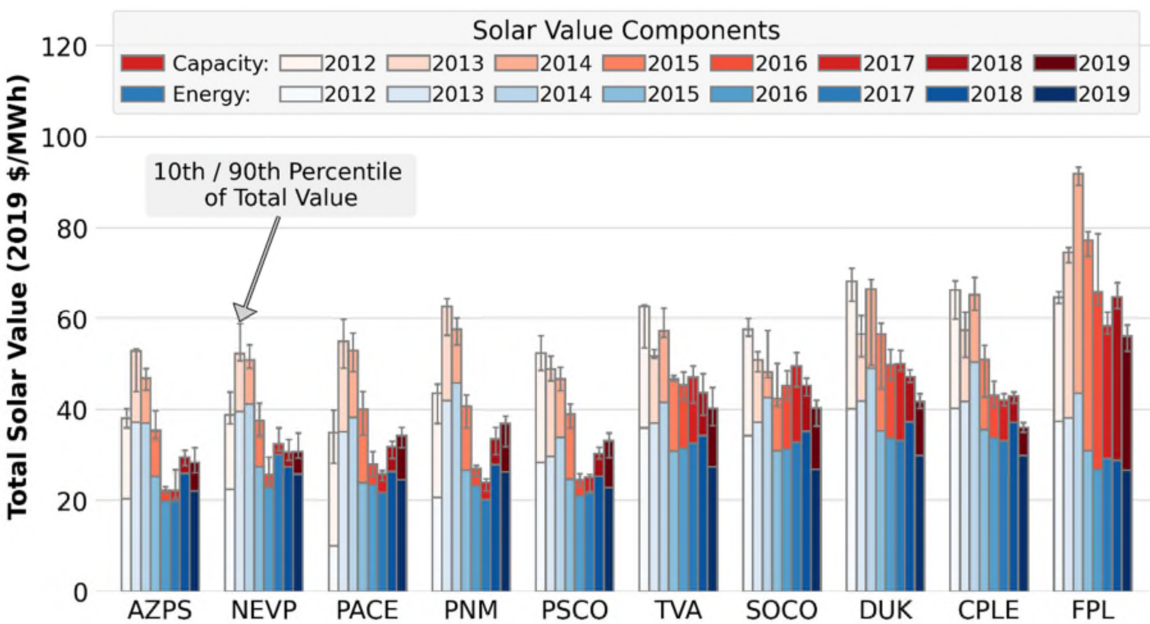

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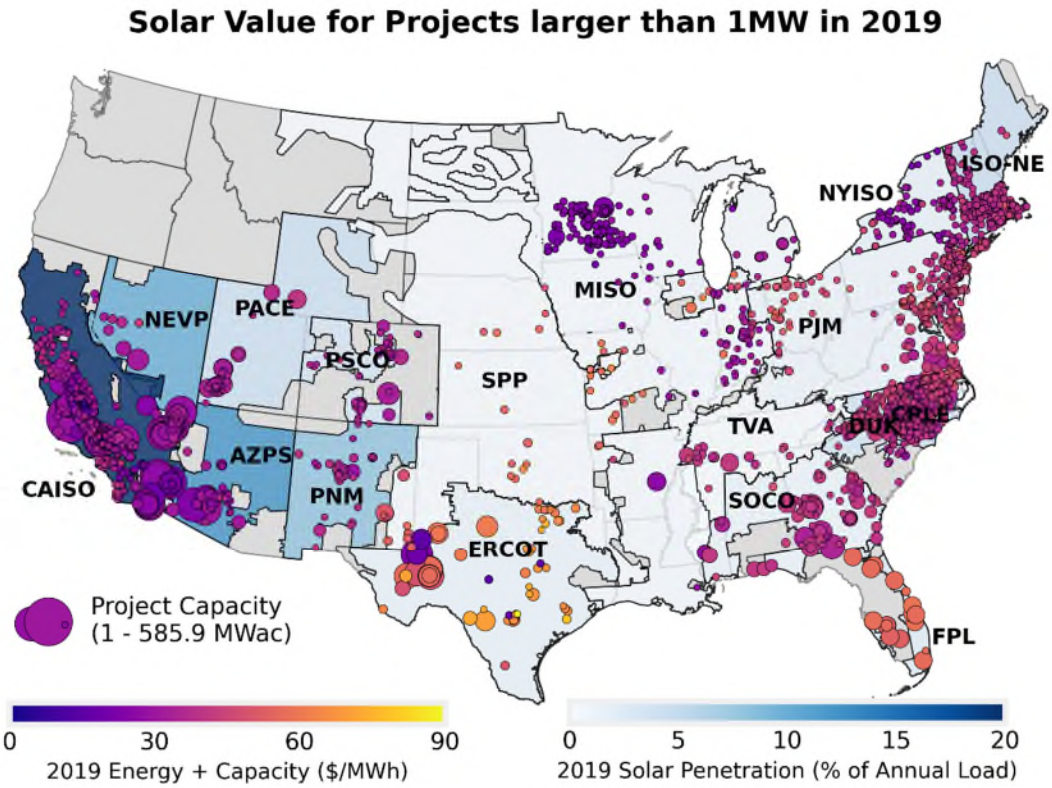
Figure 6. Combined Energy and Capacity Values of Solar Across (a) ISOs and (b) Select Set of Utilities in Non-ISO Regions



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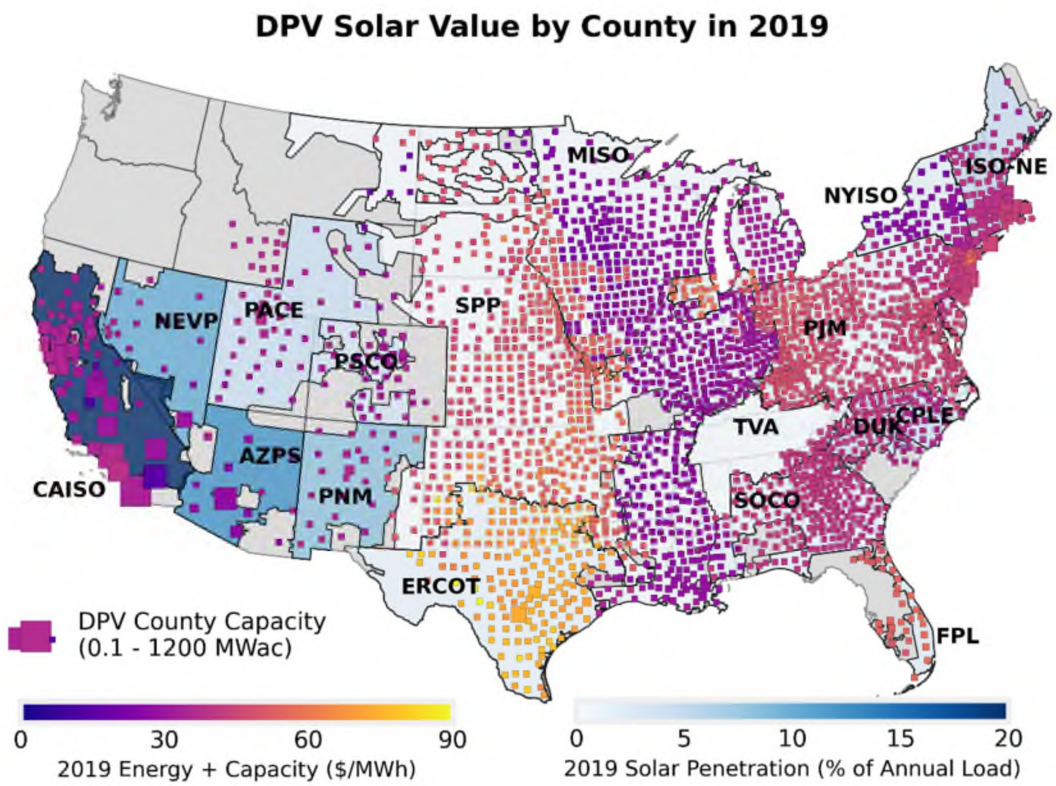


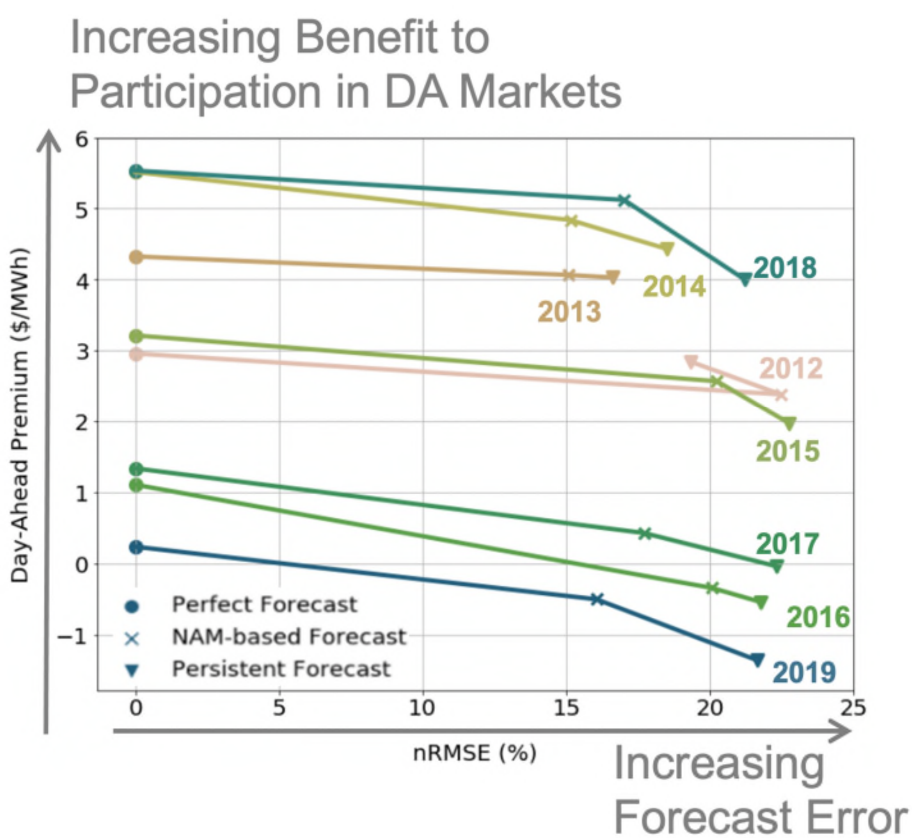
(b)

Figure 7. Mapped Energy and Capacity Values of (a) UPV and (b) DPV Across All Regions in 2019

Text Box 3. Value of Participating in the Day-Ahead Market

The energy value calculations are a product of actual solar generation and real-time (RT) market prices. Alternatively, a plant could participate in the day-ahead (DA) market using a DA forecast of generation and be paid DA market prices. Any imbalances from the DA forecast would then be settled at the RT market. We estimate the potential additional value from DA participation by calculating the "DA premium" as the difference in revenue between a solar plant that participates in DA markets (and settles imbalances at RT prices) and a solar plant that only delivers power in the RT market. Historical solar forecasts for individual PV plants are derived from the North American Mesoscale Forecast System (NAM), and are bounded on either side by a perfect forecast and a naïve persistence forecast that uses the previous day's observed solar as the forecast for the current day.

In 2019, there was little fleet-average additional value available from participating in DA markets. A $0.24/MWh premium was found with perfect foresight. This dropped to a $0.50/MWh cost when using the NAM-based forecasts. NAM forecasts are publicly available and could presumably be used by a solar plant without incurring substantial costs. Using a persistence forecast in the DA market led to further value erosion, with costs averaging $1.35/MWh. In most years and locations, however, the DA premium is positive even under persistence forecasting, though it varies significantly by plant, region, and year, and is sometimes negative even with perfect foresight. Additional results and details can be found in Wang et al. (forthcoming).



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4.5 Declining Market Value of Solar with Increasing Penetration

To provide a sense of whether solar provided above- or below-average value relative to other market participants, one can compare solar's annual value with the annual average wholesale energy and capacity prices across all generator and load nodes in each ISO. The latter effectively represents the value of a generator that operates at full capacity in all hours of the year (i.e., a "flat block" of power, also known as "around-the-clock" or ATC value). Variations in the value of a flat block between ISOs and across years capture broader price differences and trends driven by changes in the fundamental drivers of average prices, helping to contextualize the shifts in solar value.

If we divide solar's value by a flat block of power's value, the result is a convenient metric—known as solar's "value factor" (Hirth 2013)—that indicates whether solar's value is above (> 100%) or below (< 100%) average market value (as represented by a flat block of power). The equation below shows how solar's value factor is calculated:

$$Solar\ Value\ Factor = \frac{Solar\ Value}{Flat\ Block\ of\ Power\ Value}$$

By expressing value on a relative basis, the value factor normalizes changes in value that are due to broader trends in variables such as fuel and capacity prices or load growth dynamics, and it focuses on the degree to which solar's diurnal and seasonal generation profiles align with times of high wholesale power prices. This metric is, therefore, useful to explain solar valuation trends over time and to analyze the effects of increasing solar market penetration.

Figure 8a shows the relationship between the solar value factor and solar's annual (pre-curtailment) energy penetration level in each of the seven ISOs during 2012–2019. For most ISOs (ERCOT, SPP, MISO, PJM, and NYISO), solar's market value clusters at high levels, mostly ranging from 125% to 175% of the value of a flat block of power. These high value factors indicate the robust value that solar can provide due to its alignment with higher-than-average energy prices during the day and its relatively significant contributions to capacity per unit of energy (i.e., its high ratio of capacity credit to capacity factor). That said, solar penetrations in these five ISOs were at or below 2% during this period.

At higher penetration levels, solar generation can shift wholesale pricing patterns in ways that reduce solar's value. Solar's marginal operating costs of near $0/MWh can push wholesale prices during solar's peak generation hours to below where they would have been absent solar, in a phenomenon known as the "merit order effect" (see Section 5). In addition, solar's marginal capacity credit declines at higher penetrations, as peak net loads shift increasingly into the late-afternoon and early-evening hours (see Section 3). As a result, solar's total market value can decline at higher penetration levels.

The CAISO data in Figure 8a illustrate this trend. Solar's value factor in CAISO was 140% in 2012 when the solar penetration was 1.6%, but it declined to 99% (i.e., to the average level of a flat block of power) in 2015 as penetration grew to 9.5%, and fell even further to 69% in 2019, at a penetration of nearly

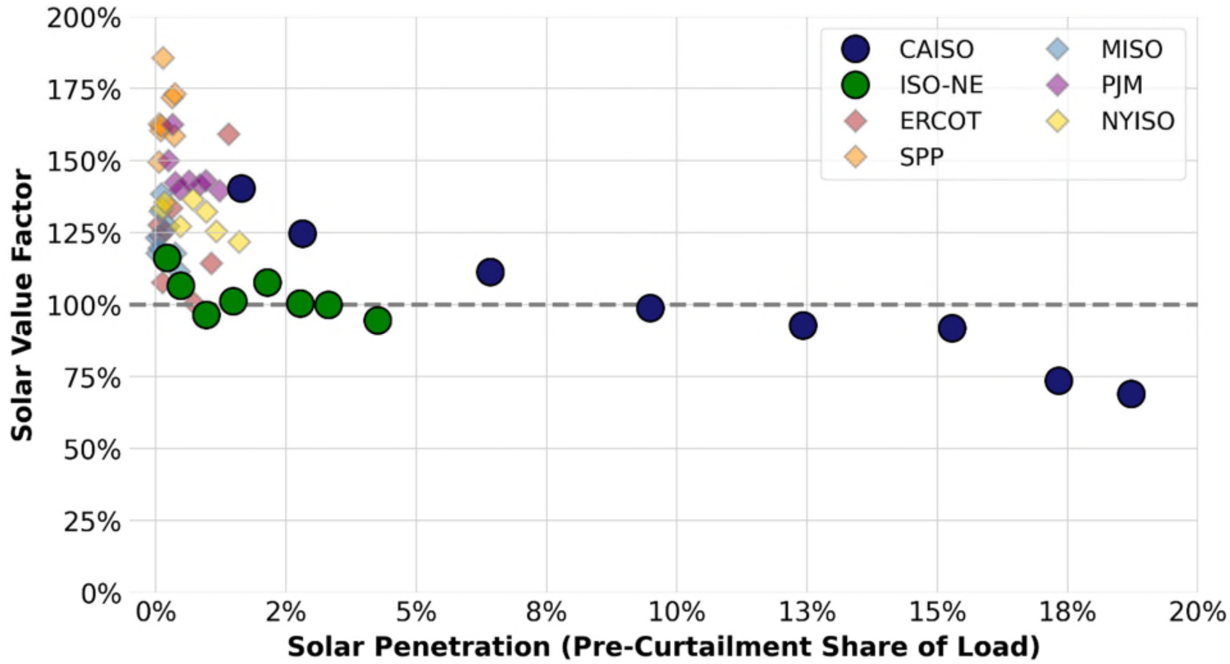
19%.

ISO-NE, which had a solar penetration of 4.3% in 2019, is the only other ISO with a solar value factor under 100% (at 95% in 2019). In contrast, CAISO's solar value factor exceeded 100% when its solar penetration was at a similar level (125% at 2.8% in 2013 and 111% at 6.4% in 2014). One potential reason for the disparity between the two ISOs could be that the highest energy prices in ISO-NE occur primarily in winter, when natural gas prices often spike owing to heating demand, yet solar generation is low.[13] Furthermore, the capacity credit of solar in the summer was much higher in CAISO, and only with the recent decline did it become as low as the capacity credit in ISO-NE. Finally, in some seasons, solar's increasing penetration in ISO-NE may be driving down energy prices during solar's primary production hours, as discussed in Section 5. Whatever the exact reasons for solar's relative value decline in ISO-NE, this market will be important to watch for further shifts in solar value as penetration continues to increase.

For most of non-ISO utilities, solar's value factor clustered between 125% and 150%, similar to most ISOs, Figure 8b. Notable exceptions were higher-than-typical value factors in FPL (159%) and PSCO (153%) at penetration rates of 2% to 3.5%. AZPS, NEVP, PNM, and PACE, on the other hand, had value factors under 100% for all solar penetration above 4%.

The value factor decline in the Southwest utilities (AZPS, NEVP, PNM, and PACE) happened at much lower penetration levels in comparison to CAISO. In CAISO the value factor did not dip below 100% until after 9.5% penetration, driven by a strong decline in energy value relative to average wholesale energy prices. Solar's capacity value declined starting in 2018, when CAISO switched to the ELCC method, as described in Section 3. Prior to this switch, the capacity credit method was based on solar production during peak load hours, not peak net load, and therefore did not decline with increasing penetration. For all non-ISO utilities, we model the solar capacity credit based on production during peak net load hours, which, like the ELCC, leads to a declining capacity credit with increased solar penetration. The decline in value factor for the western utilities may also be explained by reduced energy values as the EIM market has spread solar's "merit-order-effect" beyond the borders of the CAISO in recent years.

[13] In 2016, average natural gas prices in ISO-NE in winter were 22% higher than in the summer. In 2018 and 2019, winter natural gas prices were 164% and 138% higher than the average summer prices, respectively. Higher natural gas prices in the winter drive up winter electricity prices and reduce solar's value relative to a flat block of power. January 2018 had a particularly strong cold snap, pushing natural gas prices to an average of $15.37/MMBtu and associated real-time electricity prices to a monthly average of $107.54/MWh (ISO-NE 2019a).



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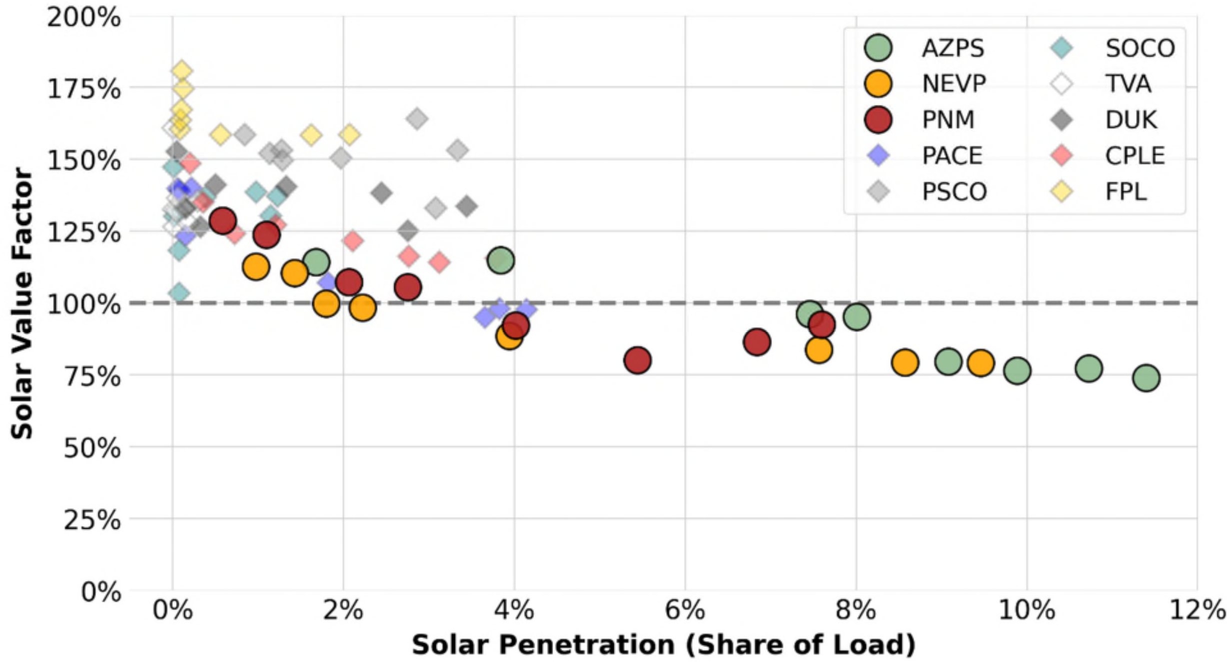

(b)

Figure 8. Solar Value Factor vs. Solar Penetration Between 2012–2019 in (a) ISOs and (b) Select Set of Utilities in Non-ISO Regions

To better understand the origin of value differences between solar generation and a flat block of power, we can differentiate the effects of location, curtailment, and profile. The first column of Figure 9 displays the energy and capacity value of a flat block of power as the simple average across all hours of the year 2019 and all generator and load nodes (just shy of 50,000). The second column down-selects to only those nodes that have either distributed or centralized solar projects nearby, and provides a solar-capacity weighted average across these roughly 4,000 solar nodes—but still assumes an output profile of a flat block of power. The third column incorporates the impact of curtailment, as any curtailed hour of solar output represents lost value (assuming coincident prices were positive). Rather than attributing curtailment to specific hours, we estimate an annual generation ratio for each node based on the post- vs. pre-curtailment generation of nearby solar installations (ranging from 65% to 100%) and then take a solar capacity-weighted average across all nodes. Column 4 finally introduces the correlation between the solar generation and price profiles, and is equivalent to the energy and capacity value presented earlier.

When examining averages across all seven ISOs in 2019, the average value of a flat block of power at solar nodes was about $3.6/MWh higher than the value at all nodes, an effect driven by the large weighting toward CAISO generators in these capacity-weighted average values and the above-average energy prices in CAISO relative to the other ISO markets. Curtailment only diminished the flat block's value by $0.5/MWh, as very little curtailment occurred relative to the total amount of solar generation in all ISOs. Introducing the solar profile has an ambiguous effect: the energy value decreased by $4.6/MWh while a MWh-denominated capacity value increased by $1.6/MWh. This counterintuitive result is explained by the fact that solar's capacity credit—which impacts the numerator—is larger than solar's capacity factor—which impacts the denominator when calculating capacity value in terms of dollars per MWh. Altogether, solar's generation across all seven ISOs in 2019 had about the same value as an average flat block of power.

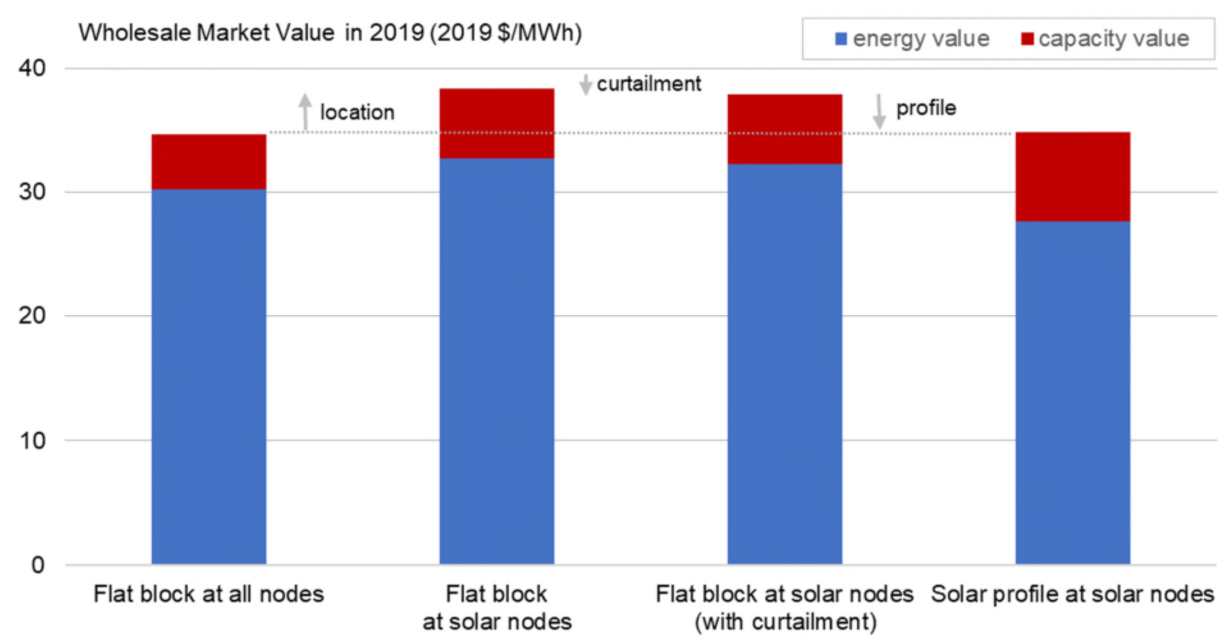

Figure 9. Differences in Value Between Flat Block and Solar Profile Across All ISOs in 2019

As national averages may be less relevant for stakeholders in individual markets, Figure 10 breaks down the effects by ISO in 2019. CAISO is the only ISO in which both location and profile lowered solar's value relative to a flat block—this is due to the large solar penetration in this market. In most ISOs, solar's generation profile has a much larger impact on value than solar's location within the ISO. Differences between the value of solar and the value of a flat block of power in the same ISO are therefore primarily due to the temporal correlation between solar generation and wholesale power prices. One exception is in ERCOT where solar tends to be sited at nodes with higher-than-average prices, leading to a large positive location effect in addition to the large profile effect.

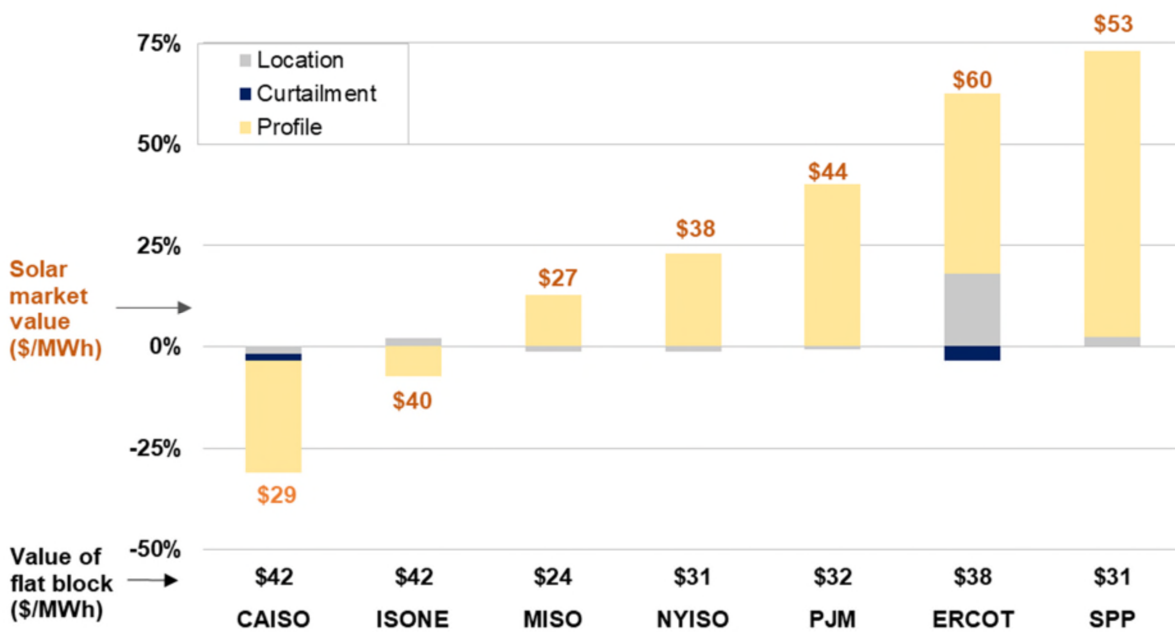

Figure 10. Average Difference in Value from a Flat Block in 2019

4.6 Market Value of Solar versus PPA Prices

To provide a general sense for how the wholesale value of solar and PPA prices compare over time, Figure 11 plots PPA prices and market value in four ISOs and two broad non-ISO regions: the West includes AZPS, NEVP, PACE, PNM, and PSCO, while the Southeast includes TVA, SOCO, DUK, CPLE, and FPL. The blue and red columns represent solar's energy and capacity values, respectively, and match the values shown previously in Figure 6. The green dots show the average levelized solar PPA price within each region among new contracts signed in each year.[14] While solar's market value within several of these regions have declined over time, falling PPA prices have largely kept pace, more or less maintaining solar's competitiveness. In some regions like PJM, the West, or the Southeast, solar's 2019 energy and capacity value exceeded the levelized PPA price of contracts signed in 2019. This suggests

[14] The ISO-level PPAs are derived from LBNL's sample of utility-scale solar PPAs, described in Bolinger et al. 2020 and accessible at https://utilityscalesolar.lbl.gov. No PPA circle is included in the chart for years and regions for which sufficient PPA data were not available in Berkeley Lab's Utility-Scale Solar Database (e.g., ERCOT in 2019).

that an offtaker in these regions who purchased solar power through a PPA signed in 2019 paid less than they otherwise would have to purchase the same amount of energy (delivered at the same time and location as solar) and capacity from the spot wholesale market. This may be one reason why the U.S. utility-scale solar market has been expanding away from California and especially into the Southeast.

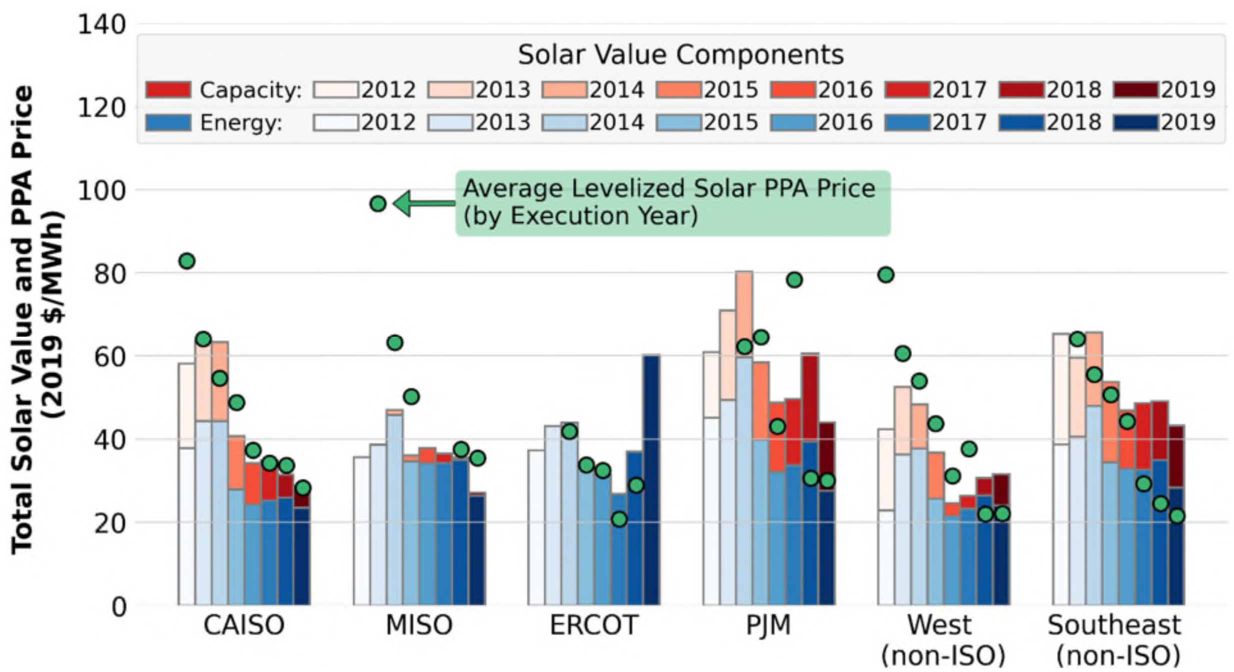

Figure 11. Solar Market Value and PPA Prices in Select Regions, 2012–2019

This comparison between levelized PPA prices and total market value is imperfect, primarily because the market value estimates are historical and only for a single year (rather than a projection of future market value), whereas the PPA prices are forward-looking and levelized over many future years. In addition, the PPA prices shown represent prices that will be paid to new solar projects, but the solar market value in each year in Figure 11 is the average of *all* solar projects operating in the market during that year. However, the solar values presented here are still marginal in nature—representing the value of incrementally increasing solar deployment—and so can be appropriately compared to PPA prices for *new* projects.[15] Furthermore, any projection of future market value will likely be heavily grounded in solar's current market value. As such, the comparison shown in Figure 11 remains a relevant indicator of the trend in solar's competitiveness.

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[15] As an alternative to looking at value on the margin and comparing it to the cost of new projects, another perspective would be to look at *average* costs and value. This approach would compare the average solar costs for all solar operating in a year, which in 2019 would include factoring the higher cost solar from PPAs executed in earlier years, to the difference in total ISO system cost with and without all of the solar. While we do have information on the average cost of all PPAs in each year, we do not have a counterfactual of total ISO system costs without solar. We therefore do not attempt to make this comparison of average costs and value.

5. Impacts of Solar on the Bulk Power System and Wholesale Power Markets

Solar energy, both distributed and utility-scale, impacts the bulk power system in many ways, with greater impacts in regions with large shares of solar, such as CAISO, and moderate to negligible impacts in others. Growth of solar changes the timing of when electricity is expensive or cheap; increases the need for flexibility owing to lower net load levels, steeper ramps, and greater short-term variability; and changes the investment signals for more flexible resources. A recent International Energy Agency report called the "Status of System Flexibility" highlights multiple phases of the bulk power system transformation with growing shares of variable renewable energy resources like solar (IEA 2019). CAISO, ERCOT, and SPP are in the third of four phases, in which variable renewables are sufficient to determine the operational patterns of the system, though in ERCOT and SPP the major driver is wind. Systems in Denmark, South Australia, and Ireland are in the fourth phase where variable renewables make up almost all generation in some periods. Variable renewables penetrations exceed 60% in South Australia, with most from wind and roughly 10% from rooftop PV (Rai and Nunn 2020). As shown below, U.S. organized wholesale markets outside of CAISO are likely to be in Phase 1, with "no relevant impact," or Phase 2, with "minor to moderate impact on system operation," at least with respect to impacts from solar. Many of the non-ISO utilities, though not assessed in the IEA report, show characteristics similar Phase 2 or even Phase 3 because of growing shares of solar.

This section evaluates the impact of solar on the bulk power system primarily through an analysis of wholesale market outcomes and a review of in-depth reports from independent market monitors. The purpose is to illustrate where the impacts of solar are readily apparent in contrast to where they are not. The analysis primarily relies on correlating the growth in solar or the timing of solar generation with apparent shifts in the bulk power system. Simply illustrating correlation does not imply a causal relationship. Evidence of strong correlation, however, motivates more in-depth analysis of causal relationships that can be conducted in future research. In some instances, relationships implied by strong correlation (or the lack thereof) are confirmed through other means, such as in-depth reporting of market outcomes by independent market monitors.

This section begins by investigating how growth in solar changes the net load, including the potential for solar to increase net load ramps and lower the minimum net load levels. The net load, defined here as the customer demand for electricity (adjusted for behind-the-meter PV) less wind and solar generation, dictates the residual needs to be met by other bulk power assets. In particular, changes in the net load indicate changes in the need for flexibility from other resources. Wholesale market outcomes, such as prices for various grid services, can, in some cases, be used to indicate the level of difficulty in providing that flexibility. One caveat is that not all actions taken by market operators are fully reflected in wholesale market prices. In those cases, using prices may miss potentially important challenges and impacts. The section focuses on real-time prices for energy, prices and requirements for ancillary services, and volatility in prices between the day-ahead and real-time markets. All of these market outcomes are brought together by examining how changes in prices impact the investment signals for flexible generation resources, particularly energy storage. To the extent that operators take actions that are not priced in the market, the investment signals for flexible generation may not be consistent with the need for more flexible resources. Though we do not discuss efforts to ensure that market designs incentivize flexibility, we do note its importance in connecting impacts of solar and investment signals for flexible resources. Finally, this section examines solar performance during periods when the grid was particularly stressed and summarizes various other notable impacts of solar on the bulk power system.

5.1 Solar Changes Net Load Shape and Wholesale Energy Prices in CAISO

As is particularly evident in CAISO, diurnal patterns of net load change with solar growth across all seasons (Figure 12). Here the diurnal patterns are illustrated by presenting the average value across a season for each hour of the day. Solar growth between 2012 and 2019 reduced the net load during the middle of the day when solar production is high. In contrast, the net load did not significantly change in the non-solar hours. This led to higher ramps in the net load, particularly in the early evening as solar production declines. The lower net load in the day and high net load in the early evening led to a reduction in midday wholesale prices, especially in the spring and fall, while peak prices shifted into later hours of the day, especially in the spring and summer. The high prices in the spring evenings in 2019 suggest a growing impact related to ramping since the net load in the spring evenings is well below peak net load levels in the summer. Not all of the net load changes were due to solar, because wind deployment also increased in CAISO during this period, though the share of energy from wind (6.9% penetration in 2019) was much lower than the share from solar.

Understanding changes in real-time prices is complicated by natural gas price changes during 2012–2019. To account for the influence of natural gas price changes, we show the diurnal patterns of the difference between the real-time wholesale price and the marginal fuel cost of a combustion turbine (CT) plant, which largely follows daily variation in natural gas prices.[16] The differences between real-time energy prices and the CT marginal fuel cost reemphasize the reduced prices during midday, especially in spring and fall, along with a shift of peak prices toward early evening hours, especially in the summer. In addition, the difference between prices and the marginal fuel cost of the CT shows that the decrease in peak prices in the summer evenings in 2019 relative to 2018 were largely driven by a decrease in natural gas prices. Had natural gas prices remained at the higher 2018 levels, the summer evening power prices in 2019 would have been closer to power prices in 2018.

[16] Additional details on the assumed heat rate, emissions rate, natural gas price, and emissions price for the CT are included in Appendix D.

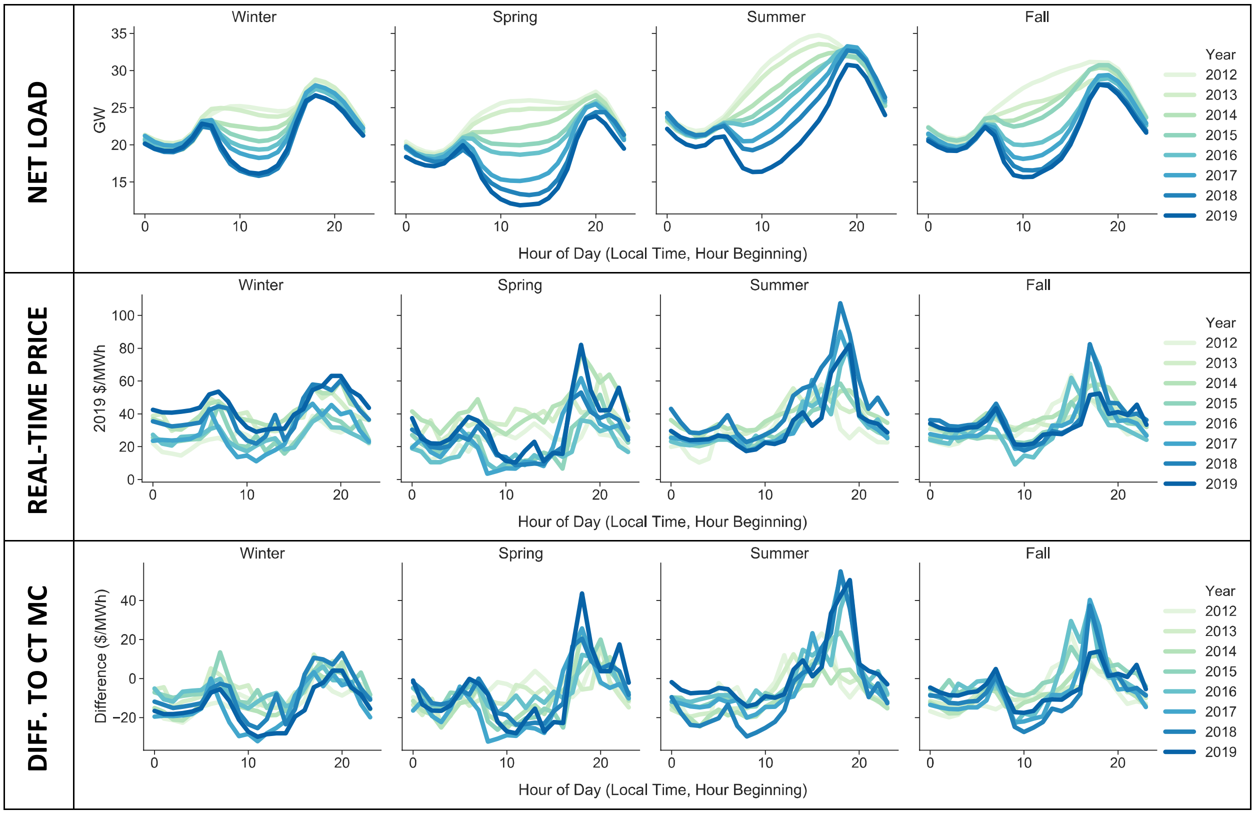


Figure 12. Net Load, Real-Time Energy Price, and Difference of Energy Prices to CT Marginal Cost (MC) in CAISO

In contrast to the readily apparent impacts of solar in CAISO, the impacts of solar are negligible to modest in other ISO market regions. After California, the ISO region with the next highest solar penetration in 2019 was ISO-NE. Slight changes to the diurnal patterns of the net load between 2012 and 2019 hint at potential changes due to solar in ISO-NE (Figure 13). The year-to-year trend is less apparent than in CAISO, though it is clear that the net load tended to be lower during midday in more recent years than in earlier years with less solar. The diurnal patterns of real-time prices and the differences between prices to the marginal fuel cost of a CT, however, do not appear to be obviously different in 2019 compared to earlier years. The only hint of a change due to solar is a slight shift in the timing of peak real-time prices toward early evening hours in the summer in ISO-NE. Results for other ISO market regions suggest negligible impacts of solar on the net load shape and real-time prices through 2019.

Growth in solar in non-ISO utility regions is also affecting the net load shape, as described in Text Box 5.

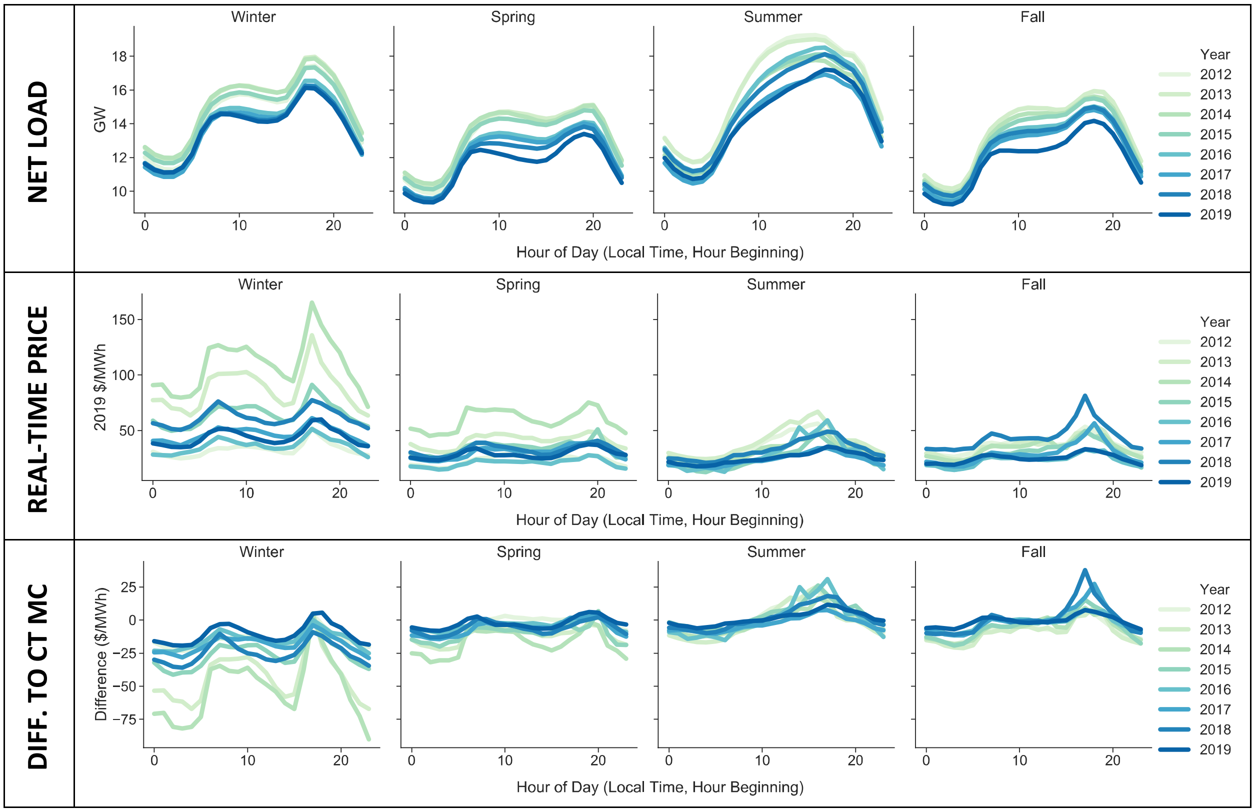
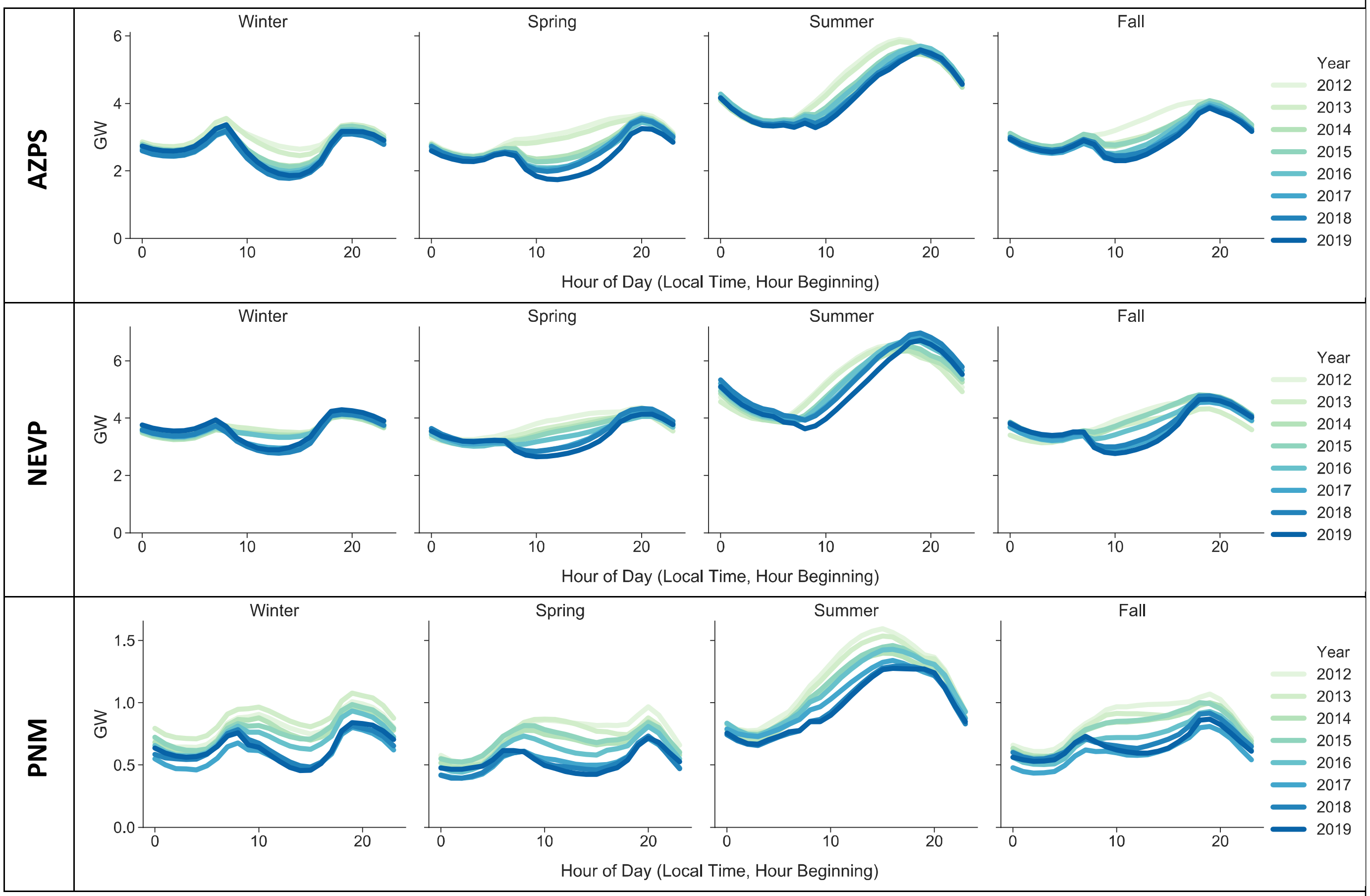


Figure 13. Net Load, Real-Time Energy Price, and Difference of Energy Prices to CT MC in ISO-NE

Text Box 5. Net Load Shapes for Three Southwest Utilities

The net load trends at three balancing authorities outside of the organized wholesale markets indicate clear and growing impacts of solar deployment through 2019. Summaries of net load for 2012–2019 are included here for AZPS, NEVP, and PNM. Growing solar in each of these regions leads to trends similar to the "duck curve" observed in CAISO. Significant growth in wind in addition to solar led to decreases in the net load even outside of solar production hours in PNM.



5.2 Lower Minimum Net Load Increases the Need for Flexibility in CAISO

Lower minimum net load levels require the rest of the power system to have the flexibility to decrease generation during low net load times at midday yet still be available to increase as the sun sets and load remains high. Only in CAISO was the minimum net load obviously lower than it would be without solar

(Figure 14).[17] In all other organized wholesale markets where solar penetration is below 5%, solar growth lowered the net load, but not to the point that it was lower than the minimum net load without solar.[18] The implication is that the flexibility needed to meet minimum net load levels did not increase between 2012 and 2019 due to solar, except in CAISO. In CAISO, solar growth shifted the minimum net load from spring nights to spring days by 2014. Additional illustrations are included in Appendix E.

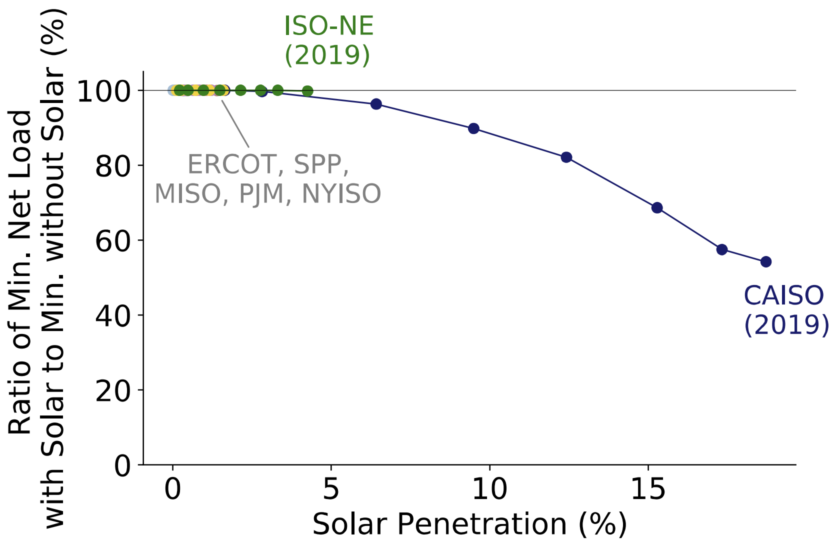


Figure 14. Impact of Solar on Minimum Net Load

An indicator of the difficulty in providing flexibility to meet low net load periods is the frequency and timing of negative prices. Negative prices can occur when available generation exceeds demand. Negative prices indicate that generators are willing to pay to continue to generate or loads must be paid to consume more electricity. The frequency of negative prices, particularly in the real-time market, rose between 2012 and 2019 in several U.S. wholesale markets (Figure 15). Solar, however, was not the primary driver of these trends in most markets, because, outside of CAISO, most negative prices did not occur during hours with solar production.

[17] The net load without solar accounts for both UPV and distributed generation. To calculate the net load without solar, we assume that the difference between the ISO-reported aggregate solar generation and our estimate of all hourly solar generation (from distributed and utility-scale solar combined) is solar generation that is otherwise embedded in the ISO-reported load. To estimate the load without solar we add to the load the hourly difference between the ISO-reported solar and our estimate of all solar generation.

[18] To avoid the influence of outliers, the minimum net load is calculated as the net load in the lowest 1% of the year.

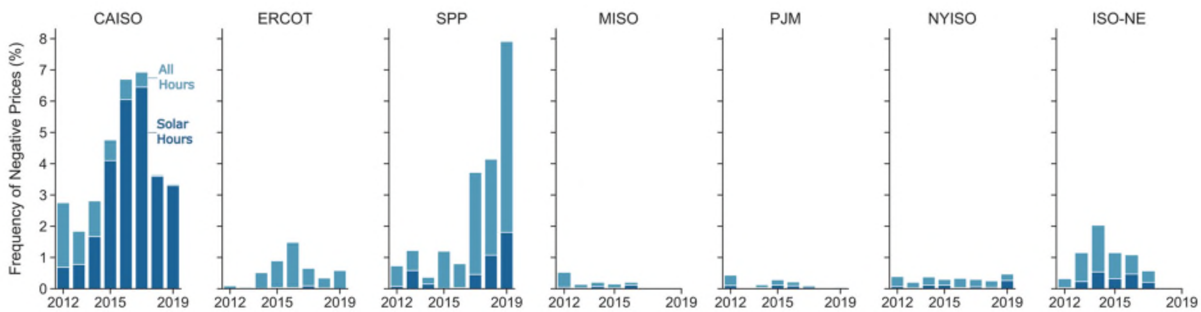


Figure 15. Frequency of Negative Real-time Prices and Share of Negative Prices During Solar Generation Hours

Solar clearly contributed to negative prices in CAISO. In 2012, only a quarter of the negative prices occurred during the day, but nearly all negative prices occurred during the day in 2019. A further refinement for approximating the contribution of solar to negative prices is to calculate the portion of negative prices in CAISO that occurred when the net load was lower than the minimum net load level without solar. In 2019, 99% of the negative prices occurred when the net load was lower than the minimum net load without solar, adding confidence that solar contributed to negative prices in CAISO. In addition to negative prices in the real-time market, the CAISO market monitor notes an increase in negative prices in the day-ahead market from 0.03% of intervals in 2017 to 1.5% of intervals in 2019. The increase, according to the market monitor, is due to additional installed renewable capacity and increased generation from hydropower resources (CAISO 2020).

In all other markets, solar did not reduce the net load below the minimum load without solar (Figure 14). Though some negative prices occurred during the day, the minimum net load hours occurred outside of solar production hours. This lack of greater demand for flexibility with solar, at least in terms of minimum net load, makes it less likely that negative prices during the day were driven by solar in the other markets.

Detailed analysis by ISO/RTO market monitors further supports the conclusion that flexibility needs with solar, with respect to minimum net loads, are not yet challenging to meet outside of CAISO. This absence of impact is expected given the low solar penetrations and the finding that minimum generation levels are no lower with solar than without (summarized in Figure 14), though impacts would be expected with higher solar penetration. Some market monitors examine how often resources were marginal.[19] A variable renewable resource with near-zero marginal costs, like solar, would only be marginal if prices were near or below zero. The PJM market monitor, for example, indicates that solar was a marginal resource less than 0.07% of the time in 2019 (Monitoring Analytics 2020). The SPP market performance report does not specifically include a category for solar, though it shows that the "other" category was marginal less than a few percent of the year in 2018 (SPP 2019). The market

[19] If a resource is marginal, or "on the margin", then at that particular time it would be dispatched in response to a change in the system conditions. Alternatively, when a resource is inframarginal it is dispatched to its full available capacity. When a resource is extramarginal it is dispatched to its minimum generation level.

monitor report for NYISO similarly shows that the "other" category was never marginal (Potomac Economics 2019). ISO-NE reports that solar was never marginal in the day-ahead or real-time market in 2018 (ISO-NE 2019b).

While solar was a contributor to negative prices in CAISO, solar growth has not steadily increased the frequency of negative prices. Proactive steps by CAISO to increase the provision of flexibility, for example, moderated the frequency of negative prices in 2019, even though solar grew during this same period (Figure 15). The CAISO market monitor suggests that the frequency of negative prices decreased after 2017 owing to less hydropower and to continued growth in access to flexible resources through expansion of the Western Energy Imbalance Market (CAISO 2019a). Economic curtailment of solar in CAISO, discussed in Section 4, can also be considered as a source of flexibility that limits the magnitude of negative prices.

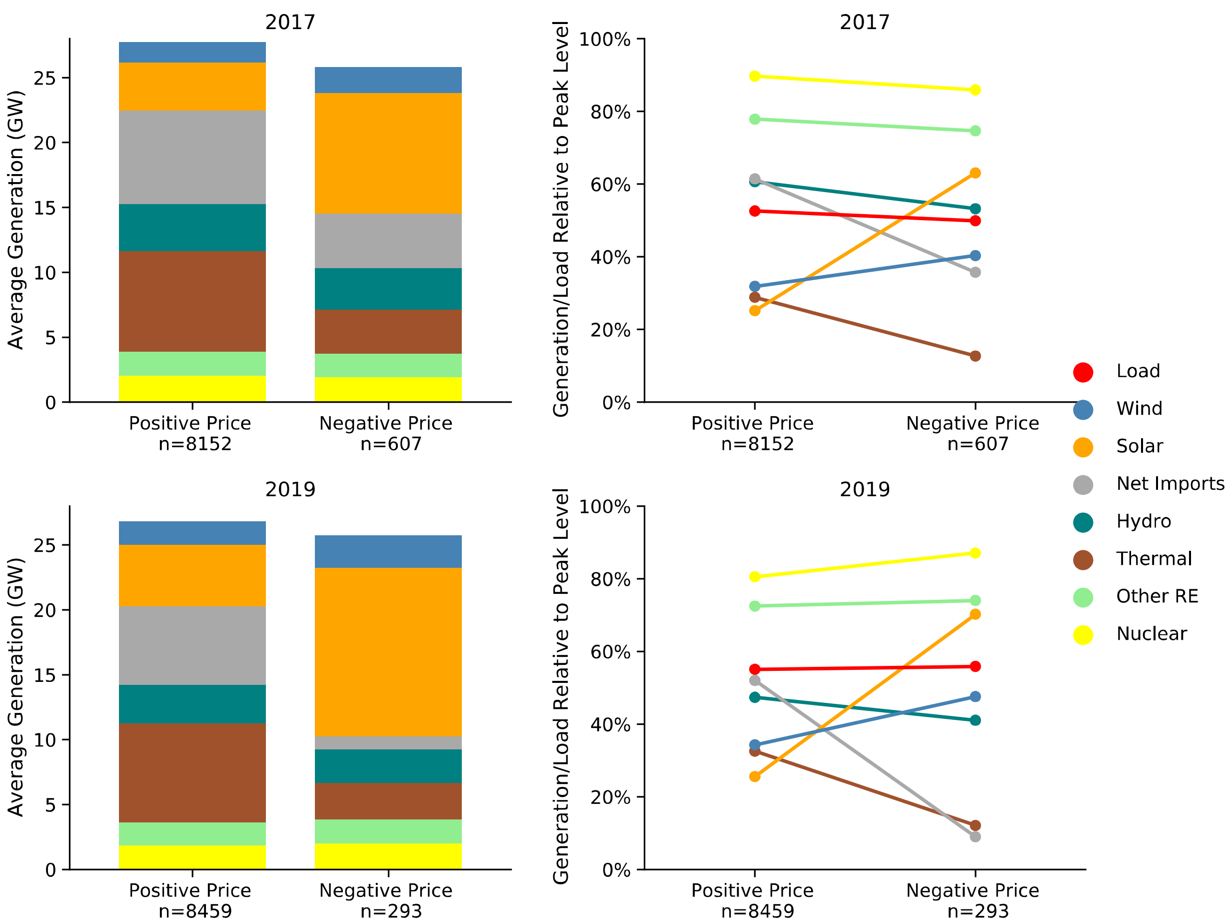


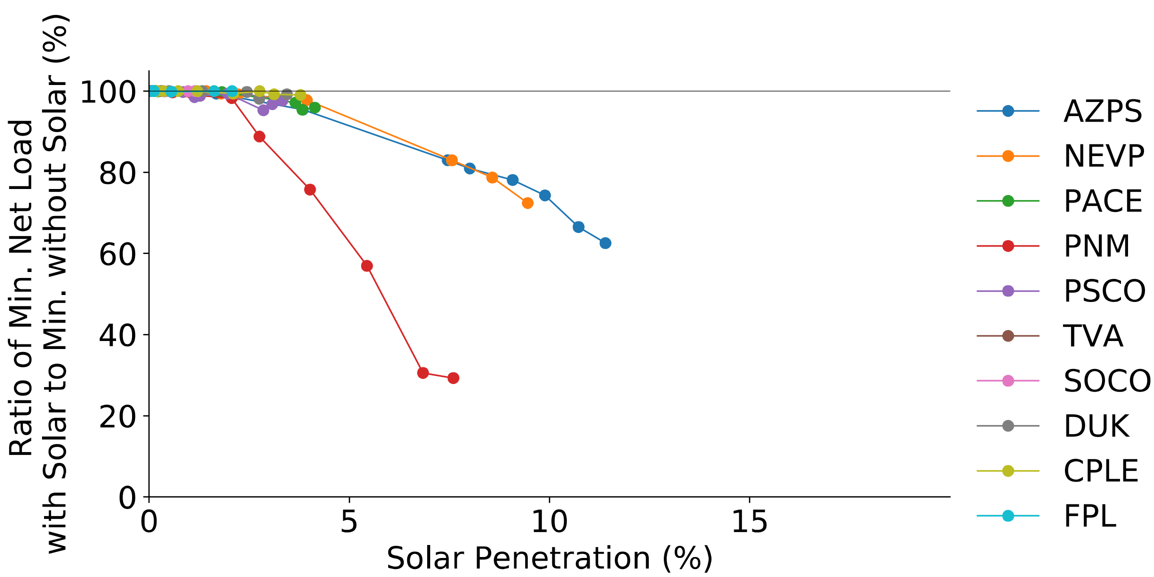
Figure 16. Average Generation During Positive and Negative Price Periods in CAISO Between 2017 and 2019[20]

[20] Load is the ISO-reported load modified by the estimated DPV in each region, as described in footnote 17. Solar is the combination of UPV and DPV.

Figure 16 shows the average generation level of various resources during positive and negative price periods in CAISO for both 2017 and 2019. The smaller bars for hydropower during both negative and positive price hours in 2019 compared to 2017 indicates that there was less hydropower availability across the year. Depending on the time of year, high hydropower availability can lead to high minimum generation levels for hydropower to maintain river flow conditions and reservoir storage capacity. Lower hydropower levels, on the other hand, are generally accompanied by lower minimum generation levels and can lead to greater flexibility. The smaller bars for thermal and net imports during negative prices in 2019, relative to 2017, indicate that imports and thermal generators were more responsive to negative prices and provided greater flexibility. In the case of imports, this greater flexibility could be due in part to the coordination provided by the Energy Imbalance Market.

Text Box 6. Impact of Solar on Minimum Net Load for Non-ISO Utilities

Similar to CAISO, solar growth in several non-ISO utilities lowered the net load to levels below the minimum net load without solar. This is particularly true for PNM whose minimum net load was already low due to wind and was further reduced by the addition of solar. By 2019 the net load was 30-40% lower with solar than without for AZPS and NEVP. Solar growth shifted the minimum net load from nights to days in the spring and late fall. For the remaining utilities, the impact of solar has decreased minimum net loads by less than 5%.



5.3 Higher Net Load Ramp Rates Increase the Need for Flexibility

In CAISO, higher net load ramp rates require the rest of the power system, in aggregate, to change generation levels more rapidly than would be required without solar. In 2019, maximum net load ramp rates in CAISO were 30%–53% greater with solar relative to the maximum ramp rate without solar (Figure 17). In contrast, for all other organized wholesale market regions where solar penetration was below 5%, the maximum net load ramp rates with solar were less than or equal to the maximum rate without solar. In ISO-NE in particular, adding solar reduced the maximum net load ramp rate by 1%–6% because solar generation in the morning tended to mitigate the large ramps associated with the morning pickup in load. The implication is that the flexibility needed to meet net load ramps increased because of solar growth for CAISO, whereas in other markets the flexibility needed to meet ramps was no larger or even less with solar deployment between 2012 and 2019. Additional illustrations are in Appendix E.

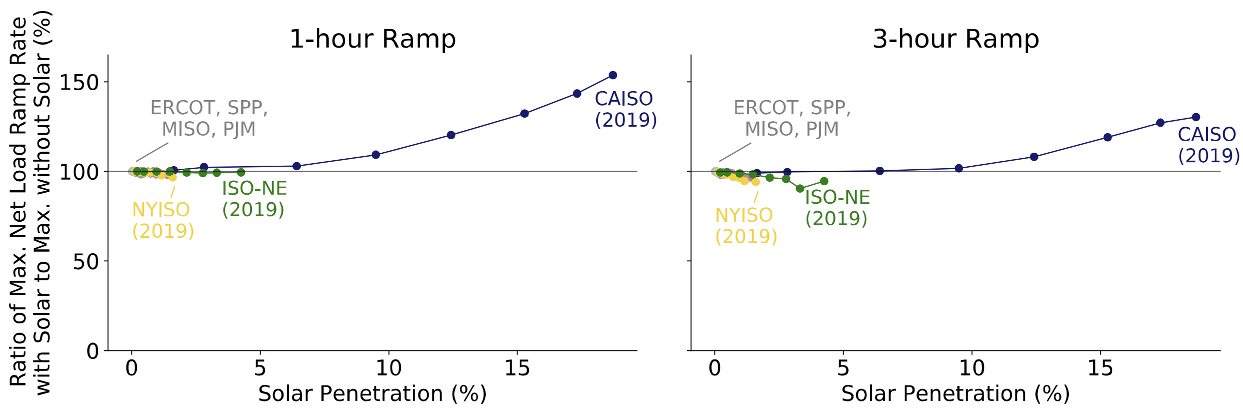


Figure 17. Impact of Solar on Maximum Net Load Ramp Rate

The CAISO evaluates its ability to meet the net load ramps by calculating NERC's Control Performance Standard 1 (CPS1) on an hourly basis. The CAISO has indicated that it is experiencing challenges in balancing supply and demand during sunrise and sunset because its CPS1 hourly performance tends to be less than 100% during these times. The CAISO is exploring several mitigating measures to address these challenges. Several additional proxies of the challenges in meeting net load ramps are available. High net load ramps could require the dispatch of resources that are more flexible but have high marginal costs, such as a CT. When a more expensive resource is needed, energy prices are expected to increase. Price spikes, particularly when solar is increasing the net load ramps beyond the level without solar, could therefore be a proxy for periods limited ramping flexibility.

What constitutes a price spike depends on system conditions and market rules. For simplicity, we define a price spike as any price that exceeds three times the marginal cost of a typical natural gas-fired CT. The marginal cost is based on the daily varying natural gas price in each market region and the cost of carbon dioxide emission permits in CAISO, NYISO, and ISO-NE. Additional details are included in Appendix C.

The frequency of price spikes in 2019 was greatest in SPP (Figure 18). These price spikes, however, were unlikely to be related to solar ramping because, as shown in Figure 17, adding solar did not impact the maximum ramp rate in SPP relative to the maximum ramp rate without solar. Similar reasoning applied to the other regions suggests that solar ramping did not contribute to price spikes. The one exception is CAISO, where price spikes that occurred when net load ramps were greater because of solar increased from 8% of all price spikes in 2017 to 18% in 2019. Increasing prices during mornings and early summer evenings for 2016–2019 in CAISO, as shown previously in Figure 12, also suggest potential price increases due to solar ramping.

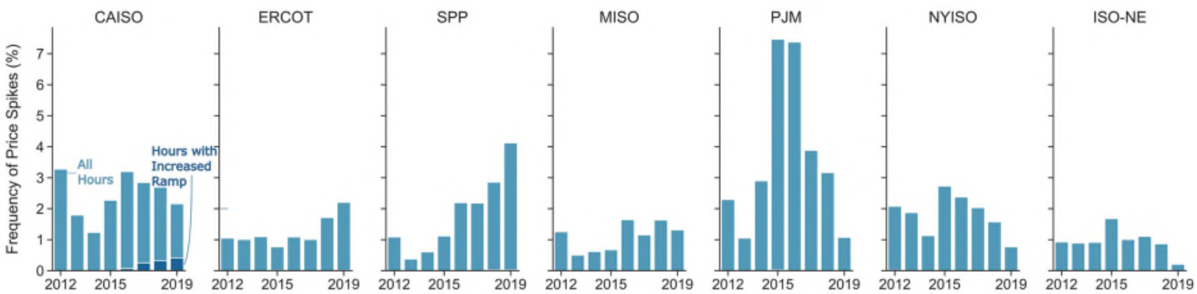


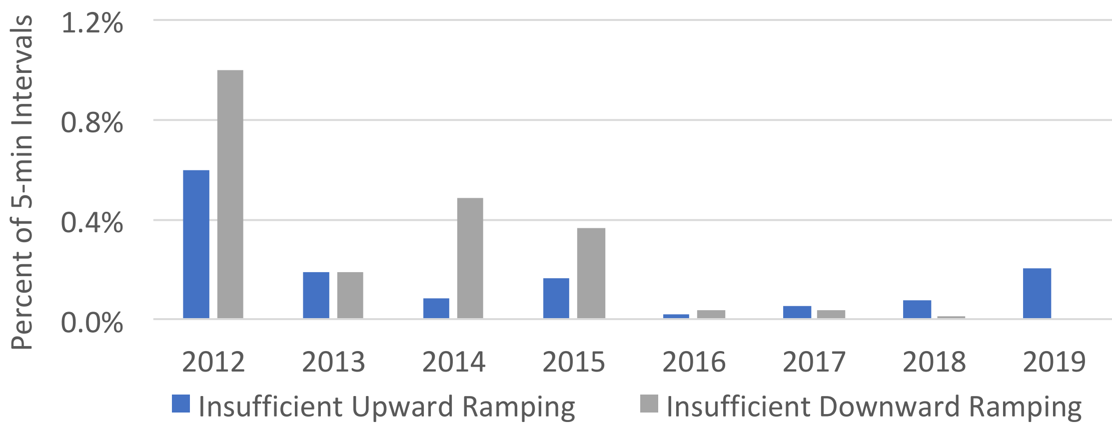
Figure 18. Frequency of Price Spikes and Fraction of Spikes Occurring When Net Load Ramps With Solar Exceed the Maximum Net Load Ramps Without Solar

Two other proxies for the challenges with meeting net load ramps are available in CAISO. Both proxies suggest net load ramps have been manageable, though challenges may be growing. The first is the frequency of what CAISO calls "power balance constraint violations." The software used by CAISO to dispatch resources at least cost while maintaining secure operations includes a constraint that requires supply and demand to be kept in balance. During challenging system conditions, this power balance constraint may not be met, leading to a relaxation of the constraint.[21] An increase in the frequency of violations as solar has grown would indicate insufficient ramping flexibility. Instead, the CAISO market monitor reports that, even as solar has grown in CAISO, the frequency of power balance constraint violations—due to insufficient upward or downward ramping capability—has remained very low (Figure 19). The reduction in recent years is largely attributed to increased transfer capability with the Western Energy Imbalance Market as the number of participants has grown, increased bidding flexibility from

[21] Relaxation of the constraint does not imply an immediate reliability issue, as explained by the CAISO market monitor (CAISO 2015):

> When brief insufficiencies of energy bids that can be dispatched to meet the power balance software constraint occur, the actual physical balance of system loads and generation is not impacted significantly nor does it necessarily pose a reliability problem. This is because the real-time market software is not a perfect representation of actual 5-minute conditions. To the extent power balance relaxations occur more frequently or last for longer periods of time, an imbalance in loads and generation actually does exist during these intervals, resulting in units providing regulation service to provide additional energy needed to balance loads and generation. To the extent that regulation service and spinning reserve capacity are exhausted, the ISO may begin relying on the rest of the interconnection to balance the system, which may affect the reliability performance of the ISO system.

renewables, and more flexible hydropower scheduling. Hence, strategies to increase the available flexibility in CAISO appear to have helped manage growing net load ramps. The roles of imports and other sources of flexibility in meeting CAISOs growing net load ramps are described in greater detail in Appendix F. In parallel, system operators increasingly use manual adjustments to the load forecast to increase the supply of ramping capacity, particularly in the morning and evening ramping period (CAISO 2020).

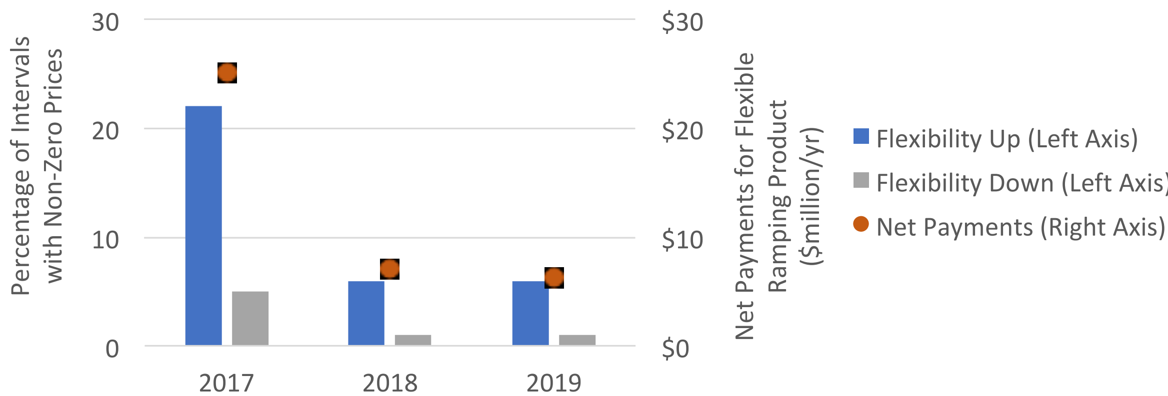


Source: CAISO market monitor reports (2014–2019)[22]

Figure 19. Percentage of Intervals With Insufficient Ramping Capability in CAISO

The second additional proxy is the flexible ramping product in CAISO. This product, which began at the end of 2016, reserves flexible capacity in the 15-minute scheduling and 5-minute real-time markets for addressing uncertainty within the intervals. With additional solar deployment, an increase in the frequency of intervals with non-zero prices for the flexible ramping product or an increase in net payments to resources providing the flexibility would suggest increasing difficulty with managing solar ramps. Instead, the frequency of non-zero prices and the net payments for the flexible ramping product decreased between 2017 and 2019 (Figure 20). The low prices for the flexible ramping product could, however, be due to market design issues according to the CAISO market monitor. In particular, the current design allows for procurement of flexible ramping from resources that may not be able to meet system uncertainty due to congestion or resource characteristics that limit flexibility. Ongoing stakeholder processes will refine the flexible ramping product to address these deficiencies (CAISO 2020).

[22] Market reports that provide these data are from CAISO (2015; 2017; 2018; 2019a; 2020).



Source: CAISO (2019a; 2020)

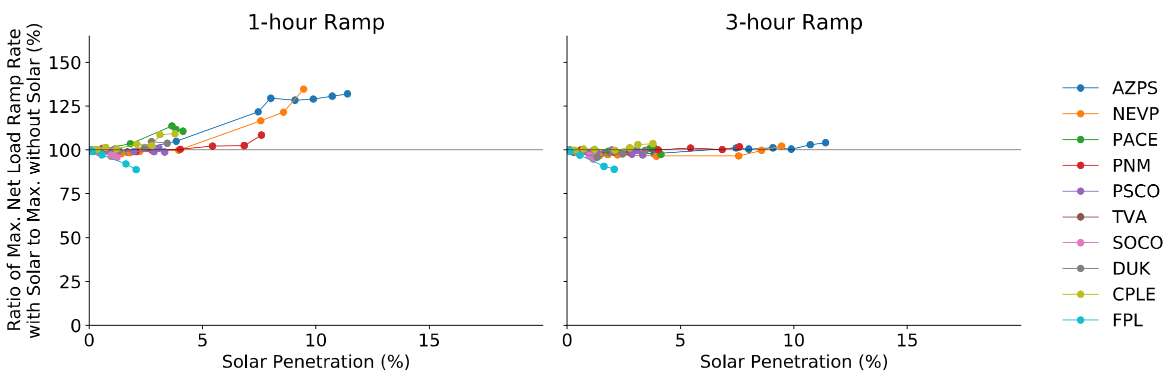
Figure 20. Non-Zero Price Intervals and Net Payments for CAISO Flexible Ramping Product

The somewhat mixed signals regarding the challenges of meeting net load ramps in CAISO are further complicated by a number of important issues. First, prices do not fully account for all of the actions that system operators take to reliably balance supply and demand. For example, the CASIO market monitor suggests that system operators are increasingly using exceptional dispatch actions to address net load uncertainty over the 1–2 hour horizon, a horizon which is not currently covered by the flexible ramping product (CAISO 2020). Second, challenges with net load ramps cannot be fully disentangled from the challenges with managing lower net-load levels. For example, a forecast of a significant multi-hour ramp driven by decreases in solar at the end of the day may require committing flexible units with high ramp rates at the start of the ramp, further contributing to minimum generation challenges and negative prices. Finally, real-time market prices are based on forecasts and when those forecasts are wrong, regulating reserves will be deployed to meet the errors. If very short-term ramps are not forecast, then market prices will not reflect the degree of challenge in meeting those ramps. Over time very short-term ramping may instead require increases in regulating reserve quantities, as discussed in Section 5.5. NERC urges industry to ensure sufficient flexible resources are available to meet increased ramping and variability requirements with growing variable generation (NERC 2020c).

Text Box 7. Impact of Solar on Maximum Net Load Ramp Rate for Non-ISO Utilities

Solar increased the maximum net load ramp rate, particularly the 1-hour ramp rate, for many of the non-ISO utilities. This indicates that solar increased the need for flexibility from the rest of the utility generation fleet. For AZPS and NEVP in particular, adding solar increased the maximum 1-hour net load ramp rate by about 32%–35%. Both utilities are members of the Western Energy Imbalance Market, which uses a flexible ramping sufficiency test to ensure sufficient internal resources to meet expected ramping needs within the hour. Both utilities failed the sufficiency test more frequently in 2019, between 2–4.5% of intervals, potentially indicating growing challenges with managing net load ramps (CAISO 2020).

In contrast, solar *decreased* the net load ramp rates by 11% in FPL. The implication is the flexibility needed to meet 1-h or 3-h ramps was no larger or even less with solar deployment between 2012 and 2019.



5.4 Short-Term Solar Variability Increases Ancillary Service Requirements and Prices in CAISO

Previous academic and industry research suggests that, in some cases, growth in the share of energy from variable renewables can increase the need for ancillary services, particularly for providing short-term balancing (Ela et al. 2017; R. Wiser et al. 2017). Depending on the study, ancillary service prices either decrease owing to generation that is no longer needed for energy becoming available to provide ancillary services, or they increase if providing ancillary services requires a unit to be online when it would otherwise be economical to be offline. In particular, Seel et al. (2018) find marked increases in the price of regulation reserves in high-solar futures across four U.S. regions.

We surveyed ancillary services requirements and prices over time for four of the markets with the highest share of solar: CAISO, ISO-NE, PJM, and ERCOT. We found that the requirements were generally flat or decreasing since 2012 in PJM, ERCOT, and ISO-NE. On the other hand, the regulations requirements increased in CAISO between 2012 and 2019.[23] Ancillary services prices similarly exhibited no clear upward trend, except for increased regulation prices in ISO-NE and CAISO. The remainder of this section focuses on regulation quantity and prices in CAISO, which demonstrate changes in response to solar, and contrasts those changes with price trends in ISO-NE and PJM that do not appear to be solar related.

In CAISO, regulation-up requirements increased modestly and regulation-down requirements increased more dramatically between 2012 and 2019 (Figure 21).[24] In particular, the regulation-up and -down requirements increased during the day in the spring season. The CAISO market monitor notes that regulating reserve requirements are greatest during the morning and evening solar ramping hours (CAISO 2020). Increased solar ramping can increase the requirements for dispatchable resources to vary output within the 5-minute real-time dispatch interval, needs that are typically met through regulating reserves.

Regulation-up prices in CAISO were highest in the morning and evening and lowest in the middle of the day and at night in all seasons (Figure 21). Regulation-up prices were exceptionally high during summer evenings in 2018. Visually, the increase in regulation prices appear to be related to solar. The CAISO market monitor, however, indicates that these high prices occurred on the "highest load days during the summer when day-ahead market energy prices were similarly high" and does not tie the increase in regulation prices to solar growth (CAISO 2019a). Further, the peak regulation-up prices decreased between 2018 and 2019 at the same time that solar and regulation-up requirements increased. Whereas regulation-up prices peaked at \$50–65/MW-h in the summer evenings in 2017–2018, regulation-up prices in the summer of 2019 were less than \$40/MW-h. The CAISO market monitor indicates that overall ancillary services costs, which include regulation, spinning, and non-spinning reserves decreased between 2018 and 2019 due to a 10% reduction in natural gas prices and lower load (CAISO 2020).

Regulation-down prices in CAISO, on the other hand, were increasingly highest in the middle of the day, with patterns that clearly match the solar generation profile (Figure 21). During the spring, regulation-down prices in the middle of the day were as much as \$45/MWh greater in 2019 than they were during the same spring hours in 2012–2015. Solar can increase regulation-down prices owing to increased regulation requirements and lower energy prices during high-solar, low net load periods. For a typical thermal unit to provide regulation down, it must be dispatched to a level that exceeds its minimum generation level and the amount of regulation-down reserve that it provides. If this energy is sold at

[23] During this same period, peak load also increased, which could contribute to an increase in ancillary services requirements. The growth in peak load (~5%) was far smaller than the growth in regulation requirements (25%–30%), suggesting additional drivers for the increase in ancillary services requirements beyond load growth.

[24] CAISO increased regulation up and down requirements starting February 20, 2016, and then decreased them again to historical levels on June 9, 2016. The increase in requirements drove an increase in regulation prices during the same period. The increase in requirements was in part due to concerns that increased variability from wind and solar led to events that depleted regulation reserves (CAISO 2016a; 2016b). In October 2016, CAISO revised its approach to calculating regulation requirements to separate regulation up and down requirement levels, include historical regulation needs, and to include anticipated needs based on forecasted weather conditions (CAISO 2016b).

energy market prices that are below the unit's marginal production costs, then the revenue from providing regulation-down reserves must make up for the losses in the energy market. The lower the energy prices, the greater the regulation-down prices must be for the unit to be willing to be online and providing the reserves.

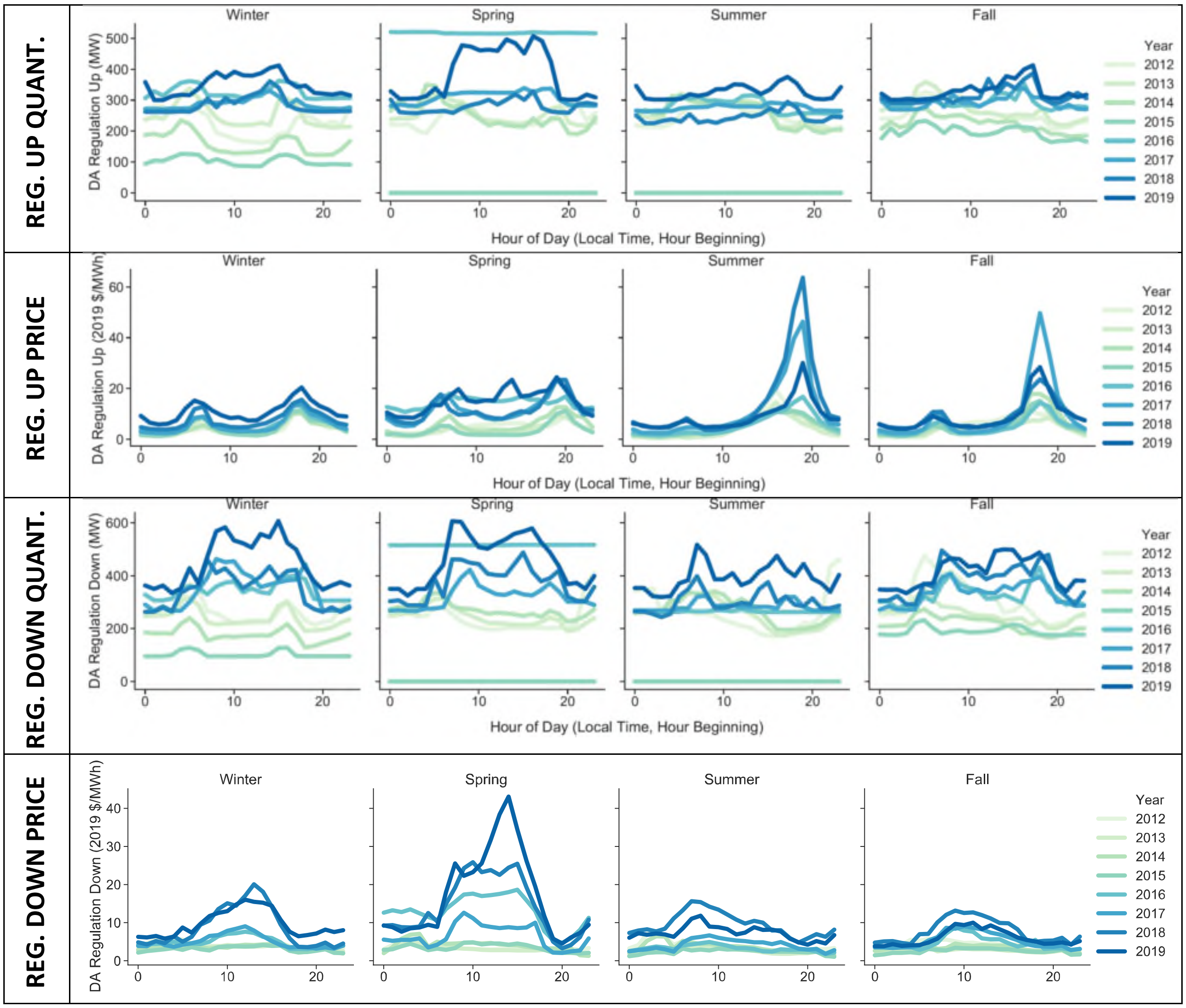


Figure 21. Seasonal Patterns of Regulation Requirements and Prices in CAISO

Although this analysis provides some insight on the impacts of solar in CAISO, not all challenges related to managing short-term variability will be reflected in regulating reserves quantities and prices. For example, CAISO staff identified instances of insufficient regulating reserves during hours with high net load ramps, which reduces CAISO performance on a key NERC balancing metric, the Control Performance Standard 1, during these events (Loutan 2018). Procuring more regulating reserves from existing resources is challenging due to the requirement that units be online and above their minimum generation level to provide regulation reserves, exacerbating the over-generation and negative pricing conditions. CAISO is therefore actively investigating potential alternative sources of flexibility.

In contrast to the observations in CAISO, regulation prices in ISO-NE and PJM do not suggest that growing solar shares have impacted regulation prices (Figure 22). In ISO-NE, the regulation market rules changed significantly after March 2015, leading to a clear sudden increase in regulation prices (ISO-NE 2019b). Average regulation prices in 2016, after the market rule change, were comparable to average prices in 2019. In PJM, average regulation prices were lower in 2019 than during 2013–2015. PJM regulation prices declined in part because wholesale prices were lower, resulting in a lower opportunity cost for resources providing this service, and the quantity of resources capable of providing the service far exceeded the quantity of the service needed.

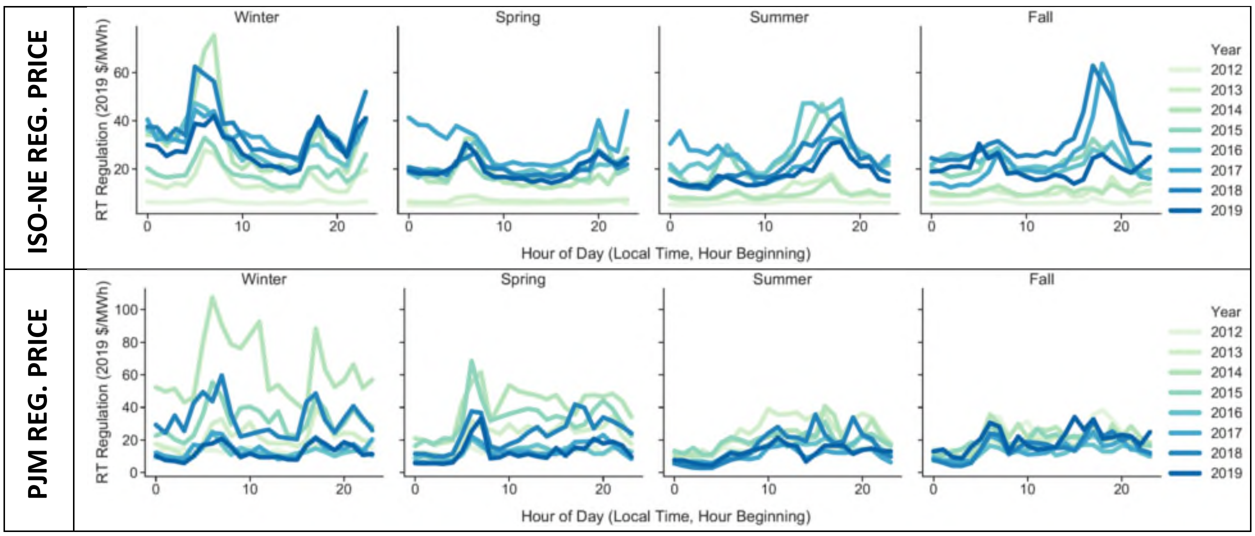


Figure 22. Regulation Prices in ISO-NE and PJM

5.5 No Clear Solar Impact on Day-Ahead and Real-Time Price Spread Volatility

Solar increased the uncertainty between day-ahead market real-time market conditions in CAISO because of errors in day-ahead solar forecasts. From 2015 to 2019, the magnitude of the largest net load forecast errors (99^{th}percentile) with solar was 35–70% larger than the largest net load forecast errors would have been without solar (Figure 23). [25][26]

[25] Aggregate day-ahead forecasts for load, wind, and utility-scale solar are reported by the CAISO and obtained from ABB's Velocity Suite. Wind and solar forecast errors are calculated as the difference between the day-ahead forecast and the actual pre-curtailment generation. In this subsection, solar forecast errors are only from utility-scale PV tracked by the CAISO. Solar forecast errors due to distributed PV are embedded in the load forecast, leading to an understatement of the full effect of solar on net load forecast errors.

[26] The impact of solar on maximum net load forecast errors decreased between 2018 and 2019 because of both an increase in the wind and load forecast errors and a decrease in solar forecast errors.

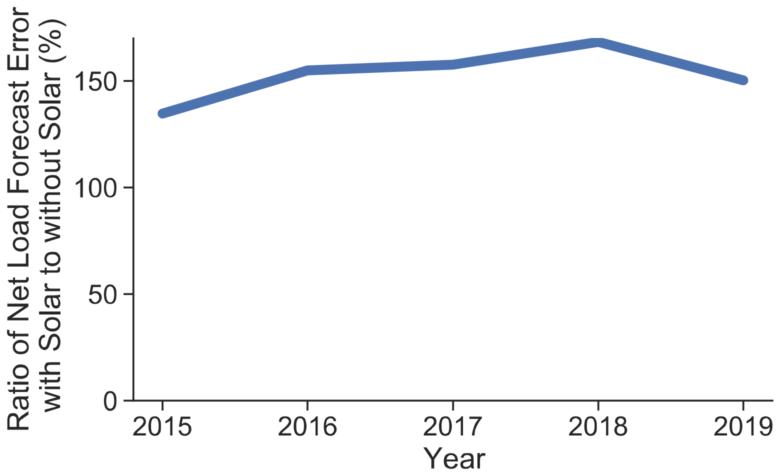


Figure 23. Impact of Solar on Maximum Day-Ahead Net Load Forecast Error

One potential indicator that this uncertainty is challenging to manage is an increased spread between day-ahead and real-time market prices—sometimes called the DART spread. A large day-ahead forecast error, for example, could necessitate use of expensive resources closer to real time, when those resources would not have been needed had actual generation levels been predicted accurately. This difference in available resources appears as a large DART spread.

Across all of the ISOs, we found no clear trend indicating that solar growth increased the volatility of the DART spread (as measured by the standard deviation of the difference between day-ahead and real-time prices). The DART spread volatility in CAISO in 2019, for example, was not visibly different than in 2012 (Figure 24).[27,28] Analysis of the average difference between day-ahead and real-time prices in CAISO similarly lacks a clear diurnal pattern that increases or decreases over time in line with increased solar deployment.

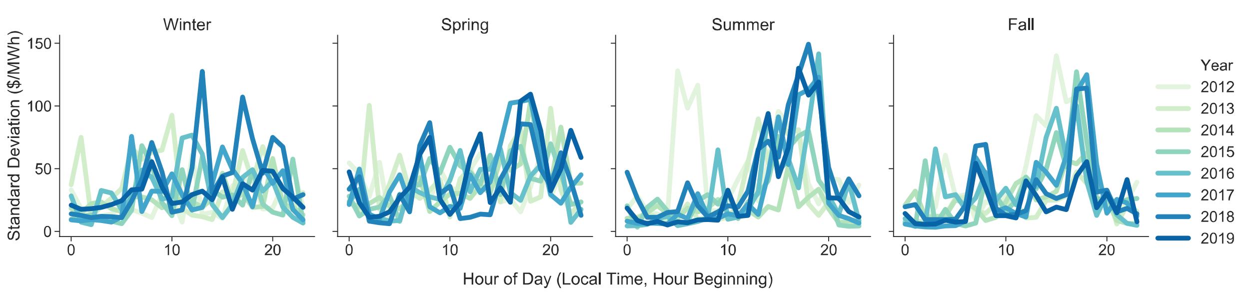
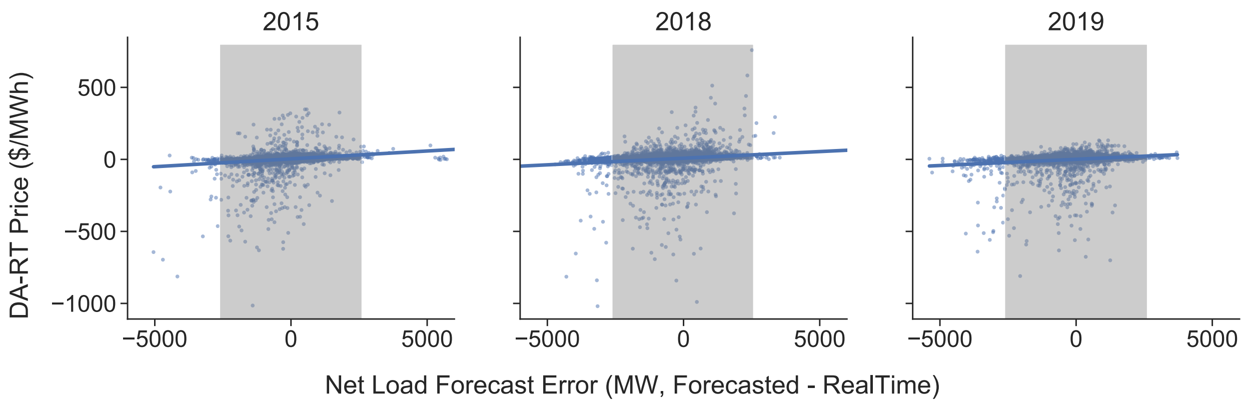


Figure 24. Standard Deviation of the DART Spread in CAISO

[27] Woo et al. (2016) use a detailed empirical analysis to find a statistically significant relationship between solar forecast errors and real-time prices. Their findings suggest that solar forecast errors contribute to a divergence of day-ahead and real-time prices on average. Here we only visually examine trends. We do not control for other factors that changed over time, and we focus on the volatility of the DART spread.

[28] The DART spread volatility, as shown in Figure 24, is nearly identical to a similar plot of real-time price volatility (not shown), indicating that the real-time volatility overwhelms the day-ahead volatility.

Even during the most extreme net load forecast errors, there is little evidence that abnormally high net load forecast errors consistently drive extreme differences in the DA and RT prices. Figure 25 uses gray boxes to show the range of the 99th percentile of net load forecast errors without solar. Net load forecasts (with and without solar) outside of this range do not drive the DART spread higher or lower than the range experienced with smaller net load forecast errors.



Note: The gray-shaded regions include 99% of all net load forecast errors without solar

Figure 25. Relationship Between DART Spread and Net Load Forecast Errors in CAISO

5.6 Increasing Incentives to Invest in Flexible Resources

Changes in wholesale pricing patterns and levels result in changes to the dispatch of flexible resources and the revenue they earn for providing grid services. Increasing shares of variable renewables are expected to increase the net revenue earned in energy markets for flexible resources and decrease net revenue for inflexible baseload resources (Wiser et al. 2017; Bushnell and Novan 2018; Woo, Horowitz, et al. 2016; Woo 2012). Here we examine changes in the net revenue of different generation types assuming that they participate in the day-ahead and real-time energy and ancillary service markets. Net revenue is defined as the revenue less any variable operating expenses (including fuel, variable operations and maintenance costs, and in the case of storage, purchases of energy from the energy market). We focus on the four markets with the highest shares of solar in 2019: CAISO, ISO-NE, PJM, and ERCOT. The representative generators include nuclear, coal, CCGTs, CTs, reciprocating internal combustion engines (RICEs), 4-hour duration electrical storage, and load-reducing demand response. Dispatch of resources is based on a “price-taker” model in which the dispatch maximizes the resources’ short-run profit assuming that prices do not change in response to the dispatch decisions. Additional details are included in Appendix G.

We find an increase in revenue in ERCOT in 2019 for all technologies due to shortage pricing associated with high loads and low reserve margins (Potomac Economics 2020). For other regions, we find that the net revenues of the representative nuclear, coal, and CCGT units in 2019 were the same as or greater than the net revenues in 2012, except for the net revenue of the CCGT unit in PJM, which decreased by about 20%. Results for these generators are included in Appendix G. Year-to-year net-revenue variation in the intervening years was significant and largely followed the trends in natural gas prices. If solar had any effect on the net revenues of these generators over this period, its impact was likely secondary to the dominant drivers.

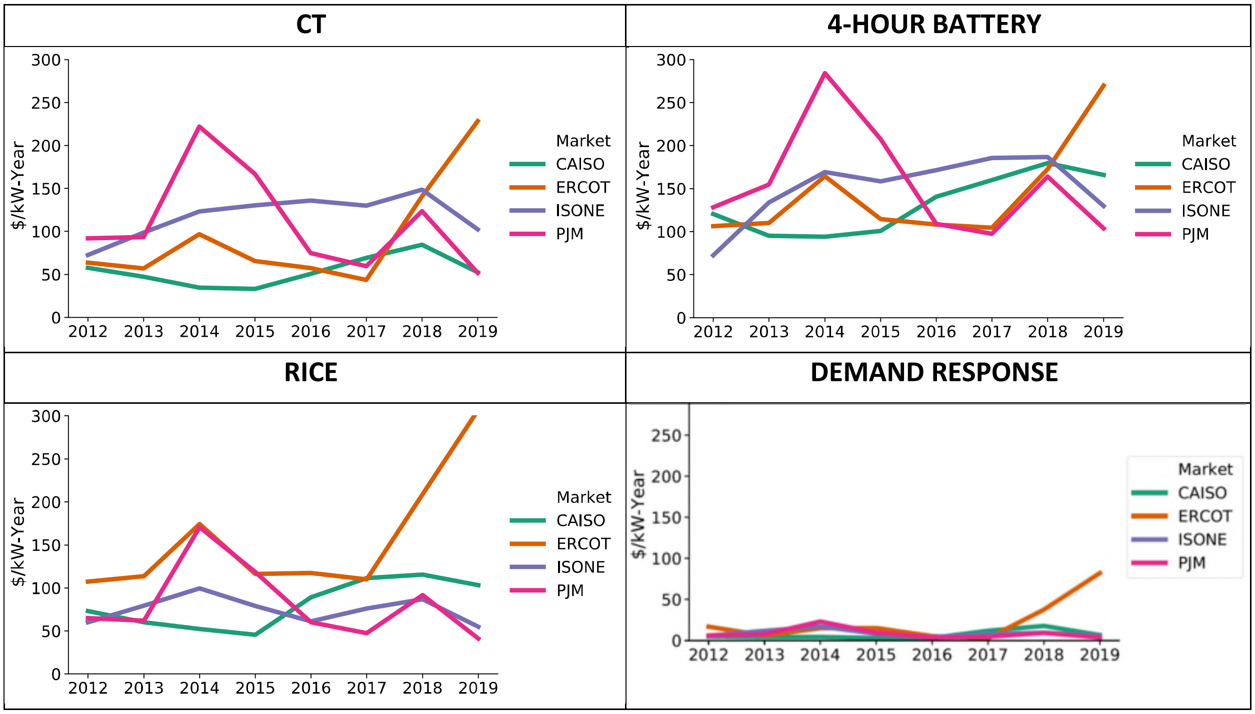


Figure 26. Net Revenues from Energy and Ancillary Service Markets for CT and 4-hour Battery in Select ISO Markets

On the other hand, net revenues of the representative flexible resources including CT, RICE, energy storage, and demand response are less sensitive to natural gas prices. The net revenues from the energy and ancillary service markets for a CT, RICE, and a 4-hour battery are shown in Figure 26. Variation in net revenue is large across years and ISOs, though, for a given region, the trends in CT and RICE net revenue tend to match the trends in battery net revenue. For the most part, the higher battery revenue compared with the CT and RICE revenue can be explained by the battery's greater ancillary service revenue; this occurs because the battery can provide ancillary services in any hour, whereas the CT can only provide regulation and spinning reserve services during its limited online hours. Similarly, the relatively higher revenue of RICE to CT can be also explained by the greater ancillary service revenue of RICE since it offers higher flexibility to provide more regulation services[29]. From one recent assessment of installed capital costs (Mongird et al. 2019), CT fixed costs (about $130/kW-yr) are lower than the fixed costs of a 4-hour lithium-ion battery (about $310/kW-yr in 2018). Battery costs are declining rapidly and are expected to reach $240/kW-yr for a 4-hr lithium-ion battery by 2025. The load-reducing demand response does not show much variation across the years, due to its more stringent

[29] The RICE engines have different flexibility assumptions from the CT in the model: RICE can ramp up to full load in 5 minutes and RICE do not have minimum down and up time.

characteristics.[30]

In CAISO, the CT, RICE, and battery net revenues steadily increased after 2015 with a slight decline in 2019 due to the relatively low energy and AS prices. To emphasize this point, Figure 27 shows these net revenues indexed to their respective values in 2012. Between 2012 and 2018, net revenues for both technologies increased by about 30%-40% and slightly decreased in 2019. For the CT and RICE, roughly half this increase was due to increased ancillary service revenue; for the battery, increased ancillary service revenue accounted for roughly 80%. Solar growth increases battery net revenue by increasing the spread between high and low prices (in part by pushing down midday prices and contributing to negative prices) and by increasing ancillary service prices (particularly regulation down). Solar's impact on CT and RICE net revenue is more ambiguous, because the late afternoon price spikes that increase CT net revenue are in part driven by load growth, and most price spikes have no clear connection to increased ramping needs from solar. A CT and RICE do not benefit from lower midday prices in the same way that storage does. A CT also cannot provide regulation down as easily without having to provide energy above its minimum generation levels at times when energy prices are low.

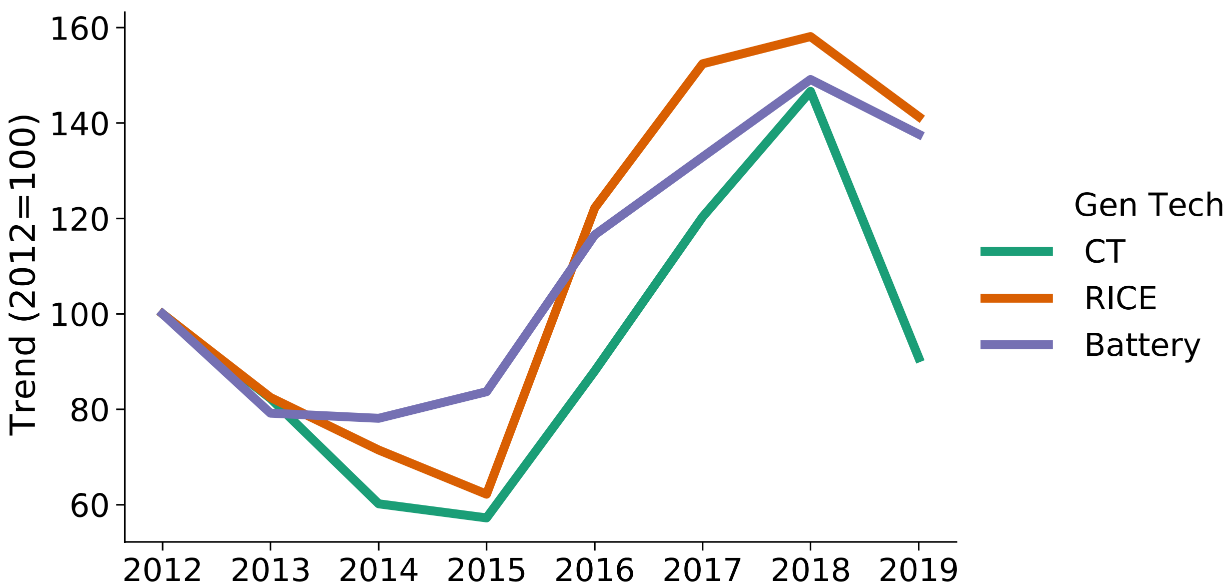


Figure 27. Net Revenues from Energy and Ancillary Service Markets for a CT and 4-hour Battery in CAISO, Indexed to 2012

5.7 Solar Generation at Times of High System Risk

In the preceding subsections, the impact of solar on the bulk power system focused primarily on impacts to market prices and the dispatch of other generation resources. In this subsection, the analysis more narrowly focuses on solar performance when the bulk power system was most stressed and had

[30] In the model, the demand response is called at full capacity with limited number of calls per year with perfect foresight. The presented results represent upper bounds where that real demand response programs have a notification period and often see response from less than 100% of the resources called upon to respond.

high risk of reliability problems. In general, the objective is to determine if solar generation tends to mitigate periods of high risk by generating during those times, thereby contributing to maintaining reliability. Conversely, if solar generation tends to be particularly low during times of high system risk, this would indicate that it does little to contribute to maintaining reliability. As in the previous discussion, the approach is to focus on observed system conditions with historical data and examine solar generation during those particular historical periods.

The North American Electric Reliability Corporation (NERC) Severity Risk Index (SRI) is the most direct measure of periods of historical system risk (NERC 2019b). It combines data on load shedding, loss of transmission lines, and generator outages in a composite daily index. A high SRI score for a particular day indicates more severe challenges with generating and delivering power to U.S. loads.

NERC publishes the highest SRI days in its annual reports (NERC 2016; 2017c; 2019b; 2020c). Based on the SRI, 2019 was more reliable than any of the previous four years (NERC 2020c), although the NERC report does not include the loss of load associated with the Public Safety Power Shutoffs in California in response to elevated wildfire risk. This analysis examines average solar generation levels during 25 days between 2012 and 2019 with high daily indices of system stress.[31] One important caveat with this approach is that because the electric power system lacks significant energy storage, system stress can sometimes be concentrated in short periods within the day. The NERC SRI does not calculate system risk on an hourly basis. The use of daily metrics cannot determine if solar contributed to mitigating risks that could be concentrated in particular hours. Daily metrics still provide insights for events that have longer duration, such as periods with constrained natural gas delivery infrastructure and heat waves.

Almost all events were weather related, including thunderstorms, hurricanes, winter cold weather, and summer heat (Figure 28). Notable events include the 2014 Polar Vortex, Hurricane Sandy, and a severe thunderstorm in 2012. During most summer events daily average solar generation tends to be above the annual average solar generation level (Figure 28a) but closer to the median for the month (Figure 28b). This indicates that solar, at least during daytime hours, is contributing to mitigating system risk during these stressful periods in the summer.

Contributions of solar in the non-summer months are more mixed with above average, around average, or well below average variations depending on the event. Even different days within the same event (Polar Vortex) saw above or below average solar generation depending on the day. For northeastern states (NYISO and ISO-NE), solar generation during Hurricane Sandy, Winter Storm Riley, and Winter Storm Avery were clearly below the annual average solar generation level (i.e., the reported value in Figure 28a is much less than 1.0), suggesting that solar was not contributing to maintaining system reliability during these times of stress.

[31] As discussed in Section 6 CAISO experienced a significant reliability event on August 14 and August 15, triggering load-shedding. This section only covers events through 2019 and does not include this or other potentially important events in 2020.

(a)

	Event Type	SRI	Date	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Summer	Thunderstorm Derecho	8.87	2012-06-29				1.2	1.4	1.5	1.4
	Severe Weather	4.40	2015-06-30	1.0						
	Coincidental Generator Outages	3.49	2016-06-20	1.3		1.1	1.3	1.5		
	Severe Weather	3.38	2015-07-18	0.6			1.3			
	Thunderstorms/Showers	3.30	2015-07-20	0.9	1.4	1.1	1.1	1.4	1.4	1.4
	Severe Weather	3.24	2015-06-23					1.3	1.2	1.1
	Severe Weather	3.20	2015-07-13					1.2		
	Summer Weather	3.10	2015-07-30	0.9	1.4	1.2	1.4	1.0	1.0	1.0
	Severe Weather	3.06	2016-08-11					1.3		
Other Seasons	Polar Vortex	11.14	2014-01-07		0.8			1.2		
	Polar Vortex	8.02	2014-01-06		0.7			0.4		
	Hurricane Sandy	7.17	2012-10-30						0.4	0.4
	Hurricane Sandy	7.04	2012-10-29						0.1	0.1
	Storm, Flooding, Straightline Winds	4.45	2015-11-17	0.9						
	Winter Storm Riley	4.22	2018-03-02						0.2	0.1
	Winter Storm Grayson	4.06	2018-01-02		0.3	0.6	0.7	1.1	0.9	0.8
	Winter Storm Avery	4.05	2018-11-15					0.1	0.2	0.3
	Winter Storm Juno	3.86	2015-01-08						0.9	1.1
	Excessive Rainfall, Thunder/Lightning Storm	3.79	2015-10-23		0.6	0.7				
	Coincidental Generator Outages	3.61	2017-05-01					1.0		
	Winter Storm	3.34	2019-02-24					0.4		
	Winter Storm Jayden	3.29	2019-01-30			0.9	0.9	1.2		
	Saddleridge Fire	3.25	2019-10-11	1.1						
	Winter Storm Indra	3.20	2019-01-21					1.2	0.9	0.9
	Winter Storms Quiana and Ryan	2.93	2019-02-25					1.6		

(b)

	Event Type	SRI	Date	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Summer	Thunderstorm Derecho	8.87	2012-06-29				0.9	1.1	1.1	1.0
	Severe Weather	4.40	2015-06-30	0.8						
	Coincidental Generator Outages	3.49	2016-06-20	1.1		0.7	1.1	1.2		
	Severe Weather	3.38	2015-07-18	0.5			1.0			
	Thunderstorms/Showers	3.30	2015-07-20	0.8	1.1	0.9	0.9	1.1	1.1	1.0
	Severe Weather	3.24	2015-06-23					1.0	0.9	0.8
	Severe Weather	3.20	2015-07-13					0.9		
	Summer Weather	3.10	2015-07-30	0.8	1.1	1.0	1.1	0.8	0.7	0.7
	Severe Weather	3.06	2016-08-11					1.1		
Other Seasons	Polar Vortex	11.14	2014-01-07		0.9			1.6		
	Polar Vortex	8.02	2014-01-06		0.8			0.6		
	Hurricane Sandy	7.17	2012-10-30						0.5	0.5
	Hurricane Sandy	7.04	2012-10-29						0.2	0.2
	Storm, Flooding, Straightline Winds	4.45	2015-11-17	1.1						
	Winter Storm Riley	4.22	2018-03-02						0.1	0.1
	Winter Storm Grayson	4.06	2018-01-02		0.4	1.0	1.0	1.4	1.1	1.0
	Winter Storm Avery	4.05	2018-11-15					0.1	0.2	0.4
	Winter Storm Juno	3.86	2015-01-08						1.3	1.4
	Excessive Rainfall, Thunder/Lightning Storm	3.79	2015-10-23		0.5	0.6				
	Coincidental Generator Outages	3.61	2017-05-01					0.8		
	Winter Storm	3.34	2019-02-24					0.4		
	Winter Storm Jayden	3.29	2019-01-30			1.3	1.3	1.6		
	Saddleridge Fire	3.25	2019-10-11	1.1						
	Winter Storm Indra	3.20	2019-01-21					1.7	1.2	1.1
	Winter Storms Quiana and Ryan	2.93	2019-02-25					1.8		

Figure 28. Solar Generation During High-Risk Events Relative to (a) Annual Average Solar Generation Levels and (b) Median Daily Solar Generation Levels for the Same Calendar Month

5.8 Other Impacts of Solar on the Bulk Power System

The issues discussed in this section relate primarily to solar impacts on operation of the bulk power system and observed market outcomes. However, impacts of solar on the bulk system are not limited to operations and market outcomes. This subsection briefly highlights several additional issues: inverter performance during disturbances, maintenance of adequate frequency response with increasing levels of solar PV and other inverter-based resources, and visibility and representation of DPV in system operations and planning.

- NERC has identified potential reliability issues associated with bulk power system-connected PV resources and their inverter settings that caused the loss of solar generating resources during disturbances to the bulk power system (NERC 2018b). This includes both tripping-related challenges and their behavior to large voltage disturbances (i.e., “momentary cessation”). Two notable events include the Blue Cut Fire and Canyon 2 Fire disturbances that resulted in the loss of 1,200 MW and 900 MW of bulk power system-connected PV in Southern California, respectively, following normally-cleared transmission line faults caused by nearby wildfires (NERC 2017b; 2018a). In response, NERC issued alerts highlighting the issue and providing industry with strong recommendations for improved performance. Two more slightly smaller events unrelated to fires happened within days of NERC issuing the Canyon 2 Fire Alert (NERC 2019a). CAISO revised its interconnection agreement to specify expected inverter performance during disturbances to the bulk power system (FERC 2019).
- NERC has also identified significant challenges and errors in the dynamic models of bulk power system-connected inverter-based resources used in bulk power system reliability studies. In particular, many of the dynamic models for existing PV resources were found to not match the expected behavior of the facility in response to large disturbances on the bulk power system. NERC is currently working with industry to address these issues (NERC 2018a).
- CAISO identified challenges with maintaining adequate frequency response as the share of inverter-based renewables increases. To ensure compliance with NERC requirements, CAISO contracts with neighboring utilities to transfer a portion of its frequency response obligation. Currently these operator actions are not included in market prices, and CAISO proposes to examine a market structure for primary frequency response procurement and compensation (CAISO 2016c). NERC is evaluating fast frequency response concepts to ensure frequency stability with increasing shares of inverter-based resources (NERC 2020a).
- NERC identified gaps in representing the potential impacts of distributed energy resources on the bulk power system, along with recommendations for addressing those gaps. Recommendations include modeling these resources explicitly in planning studies rather than netting them with load, improving representation of the resources in power system models (NERC 2019c), and sharing data across the transmission and distribution interface (NERC 2017a). NERC’s System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) continues to make progress in addressing these recommendations, including developing guidelines on the adoption of IEEE 1547-2018 by state and local jurisdictions. ERCOT additionally highlights the need to increase the visibility of distributed energy resources, including DPV, “for the ISO and market participants to assure the continued reliable operation of the ERCOT System” (ERCOT 2017).
- System operators continue to refine approaches for forecasting solar and incorporating forecasts into system operations. Multiple ISOs/RTOs are focusing on improving visibility and forecasts of behind-the-meter generation (Gheorghiu 2019a).

6. Trends That Impact Analysis

Solar deployment is projected to continue increasing in the United States, with interconnection queue activity suggesting that future additions will be more evenly spread across regions rather than concentrated in CAISO (EIA 2019; Bolinger et al. 2020). In an increasing number of cases, new solar will be accompanied by energy storage: as much as 95% of solar in entering the CAISO interconnection queue in 2019 includes storage (Bolinger et al. 2020). Depending on how this storage is used, it will alter solar's generation profile and reliability contribution in relation to historical data. Similarly, increased discussions around dispatching solar to provide essential reliability services, such as ramping or frequency response, can change the value of solar relative to solar that lacks these capabilities. CAISO certified its first solar resource to provide spinning reserve in June of 2019 (CAISO 2020).

ISOs recognize the importance of quantifying the reliability contribution of solar. CAISO decided to shift the measurement method to the ELCC, based on a probabilistic risk analysis, rather than using solar generation during peak periods. The ELCC of solar in CAISO will continue to decline with increasing solar deployment. PJM proposed revisions to its tariff to adopt an ELCC method for assessing the reliability contribution of solar, wind, and other energy-limited resources effective June 2021 (PJM Interconnection 2020). MISO staff use the ELCC to quantify the capacity credit of solar, and how it changes with increased solar penetration, in a forward-looking stakeholder advisory process called the Renewable Integration Impact Assessment (RIIA).

The capacity value of solar will be affected by any changes to the capacity credit methodology. Changes in capacity prices, however, have historically been the primary driver of changes in solar capacity value. Capacity prices are affected by many factors, including the overall reserve margin. Capacity prices tend to be lower when available generation capacity exceeds the target planning reserve margin, as is the case in many parts of the country (NERC 2020b). Capacity prices in some markets are also affected by state policies that support additional resources (ISO-NE 2020). In the near future, reserve margins are tightest in ERCOT, which led to frequent high energy prices in the summer of 2019 and could drive prices high again in future years. Adequate resources are available to meet planning reserve margins in CAISO, though issues with the natural gas storage system present challenges in Southern California, and requirements for ending the practice of once-through cooling are driving proposals to build more capacity in CAISO. Increasing tightness of the California resource adequacy market could raise capacity prices, particularly in local areas (CPUC 2019). Furthermore, the CAISO market monitor has had longstanding concerns that a significant portion of resource adequacy requirements are met by imports that may have limited availability during critical conditions (CAISO 2020). An August 2020 heat-storm across the western United States resulted in CAISO demand exceeding levels used in setting resource planning targets and subsequent load-shedding on August 14 and August 15. Three primary factors identified in a preliminary "root-cause" analysis (CAISO, CEC, and CPUC 2020) are:

1) The climate change-induced extreme heat storm across the western United States resulted in the demand for electricity exceeding the existing electricity resource planning targets. The existing resource planning processes are not designed to fully address an extreme heat storm

like the one experienced in mid- August.

2) In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.

3) Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

Recommendations from the root-cause analysis include increasing resource adequacy requirements to more accurately reflect the risk of extreme weather events and bringing additional resources online.

The energy value of solar tends to move in proportion to average electricity prices, which in most ISOs follow trends in natural gas prices. The EIA Reference Case projects steadily increasing natural gas prices after 2020 (EIA 2020a). Relationships between natural gas prices and solar energy value based on historical observations suggest that for most ISOs, where solar penetration is still less than 1%–2%, solar's energy value likely will follow natural gas prices. The relationship between solar's energy value and natural gas prices is more ambiguous in CAISO, where pricing patterns are clearly shifted by solar, and in ISO-NE, where regional constraints tend to drive natural gas price changes in winter.

Based on historical observations of CASIO, ISO-NE is at a threshold where more obvious signs of bulk power impacts from solar may start to appear. Solar penetration in ISO-NE in 2019 (4.3%) was between the solar penetration of CAISO in 2013 (2.3%) and 2014 (5.3%). As solar penetration grew beyond the 2014 levels in CAISO, minimum net load levels were increasingly set by solar and ramp rates increased beyond the level without solar. Whether meeting lower minimum net load and higher net load ramp rates levels is challenging the ISO-NE system depends on the flexibility of ISO-NE resources and imports.

As described in Section 5.7, changing pricing patterns in CAISO increased incentives to invest in flexible generation. The attractiveness of storage is further aided by significant declines in the cost of lithium-ion batteries and by supportive policies such as the California storage mandate and a Clean Peak Standard in Massachusetts. Ongoing efforts to refine price formation at several ISOs, including the CAISO, are designed to ensure prices reflect actions that system operators take to maintain reliability and send the right investment signals for flexible resources.

Future refinements to this analysis will use historical dispatch of solar+storage plants to identify the incremental impact of adding storage to solar plants. The analysis will identify the incremental impacts to the contribution to reliability, market value, need for flexibility, and production during days with high risk of outages.

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Appendix A. Solar Generation Methods, Data, and Validation

The goal of this analysis is to create location-specific hourly solar generation profiles for all solar deployed in the seven organized wholesale markets along with a select set of non-ISO utilities. This section describes how the solar capacity is defined, the profiles are created, and the profiles are validated.

Solar Capacity Deployment Data

The universe of solar installations used in this analysis draws from two primary data sources: we use plant-level information detailed in EIA Form 860 to build our sample of utility-scale solar projects and state-level capacity data reported in EIA Form 861 to build our sample of residential and non-residential DPV installations. Both primary data samples are refined by either leveraging verified plant-level information from LBNL's utility-scale solar database (Bolinger, Seel, and Robson 2019) or by supplementing state-level DPV capacity data for years prior to 2014 (the year in which EIA Form 861 coverage begins) with information from the Solar Energy Industries Association (Wood Mackenzie and SEIA 2019) and the Interstate Renewable Energy Council (IREC, for annual installations prior to 2010).[32]

State-level solar capacity data are then allocated to the seven ISOs and non-ISO utilities based on plant-level attributes (provided by ABB for utility-scale solar projects) or via annual capacity coefficients derived from balancing authority data reported in EIA Form 861 net energy metering (NEM), for DPV. DPV capacity is further temporarily prorated to yield monthly cumulative region-specific capacity. Empirical geographic installation records from LBNL's Tracking the Sun database (Barbose and Darghouth 2019) are used to develop state-county DPV sectoral capacity ratios, which in turn are further refined based on census household data for those counties that span multiple Balancing Authorities.

Solar Generation Profiles

Solar generation profiles are intended to capture historical insolation and the characteristics of individual plants. We first use National Renewable Energy Laboratory's SAM[33] with historical hourly insolation data from the NSRDB[34] to simulate hourly solar generation from 2012 to 2019. SAM default assumptions are used for inverter efficiency, system losses, and ground coverage ratio, which are 96%, 14%, and 0.4, respectively. For utility-scale installations, plant-specific characteristics are used as much as possible (such as geographic coordinates, presence of tracking systems, tilt angle for fixed-tilt

[32] State-level DPV capacity data from IREC did not distinguish between residential and non-residential data; we used the first available sector-specific data for each state to backfill prorated sector capacity. Our aggregate national sample of solar capacity may not include off-grid installations or, for example, some military installations that are not reported via EIA Form 860. However, the 51 GW_{AC} of our sample compare favorably with the 62 GW_{DC} covered by SEIA at the end of 2018, assuming a 1.2 direct current (DC) to AC ratio for distributed capacity and 1.3 for utility-scale projects.

[33] https://sam.nrel.gov/

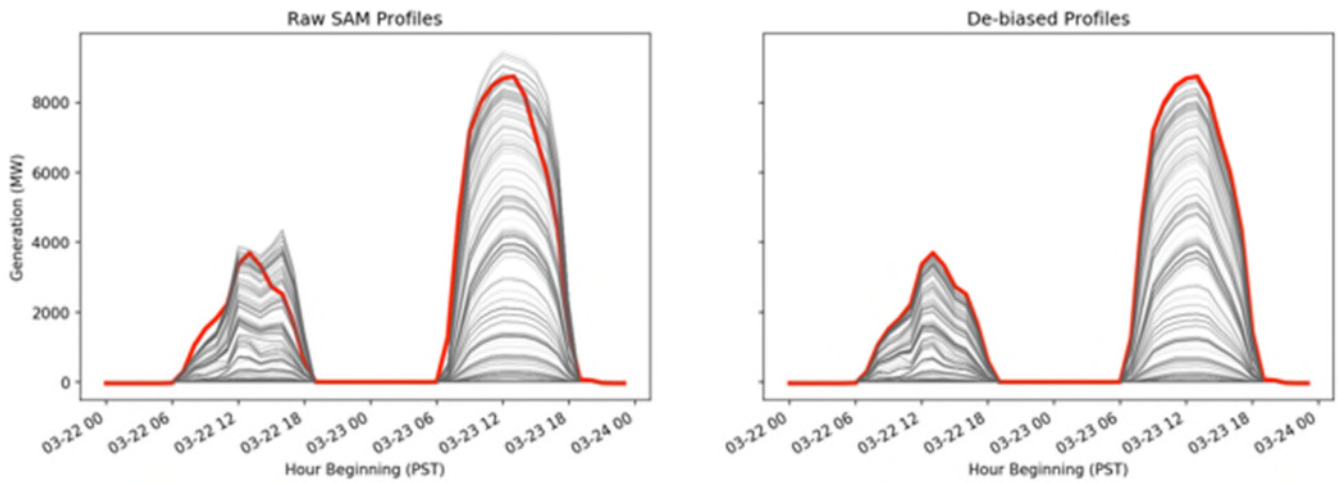
[34] https://nsrdb.nrel.gov/

installations, azimuth, and DC-AC ratios). For DPV installations, we model fixed-tilt systems augmented with regionally specific characteristics for the tilt derived from LBNL's Tracking the Sun Database (Barbose and Darghouth 2019). We use SAM defaults for the DC-AC ratio (1.2) and a blend of azimuths of 160, 180, and 200, weighted at 25%, 50%, and 25%, respectively, to approximate the distribution of azimuths found in the Tracking the Sun Database.

For UPV facilities, we next use any available solar generation data to refine our estimates of plant level solar profiles (and revert to the raw SAM profile when no additional data is available for refinement). We "de-bias" raw SAM profiles using individual plant generation data from EIA and, depending on data availability, aggregate balancing authority-level hourly generation profiles. The de-biasing process helps to adjust for factors not captured by SAM that impact real plants (e.g., curtailment, soiling, snow cover, etc.).

To de-bias the raw SAM profiles, we first adjust plants for curtailment where such data is available. We then use an iterative scaling process to force individual plant output to equal their reported monthly totals, and to force the regional sum of plant output to equal the reported total by region. Specifically, for each plant, the hourly time-series is summed to monthly totals and then linearly scaled so that the monthly total matches reported generation totals for that month (reported in EIA Form 923). Note that this scaling is applied equally to all hours in a month, unless it raises the generation above 100% capacity, in which case the output for that hour is limited to 100% capacity. Then, for each hour, we sum the generation of plants we assume are included in the reported hourly aggregate profiles at the balancing-authority level, and we scale the generation of all plants in that hour so the total equals the total reported by the balancing authority. Again, we limit output for any individual plant to less than or equal to 100%. These two steps are then repeated until the values converge (i.e., the values change minimally between each iteration). At this point, the generation from each plant matches the monthly total from EIA and the hourly total from each balancing authority.

We validate this debiasing technique in the following section, but first, Note: Individual profiles on the left use the raw SAM output while profiles on the right are de-biased. Individual PV plant profiles are gray and aggregate CAISO solar profiles are in red.
Figure A-1 provides an illustrative example of the effectiveness of this technique in CAISO for two days in 2018. The figure on the left shows the cumulative raw SAM profile compared to the actual aggregate CAISO hourly profile. The figure on the right shows that de-biasing the individual profiles (gray) better aligns solar production with the actual observed aggregate solar profile (red).



Note: Individual profiles on the left use the raw SAM output while profiles on the right are de-biased. Individual PV plant profiles are gray and aggregate CAISO solar profiles are in red.

Figure A-1. Illustration of the Effectiveness of De-biasing Individual PV Plant Profiles Using Aggregate CAISO Solar Profiles

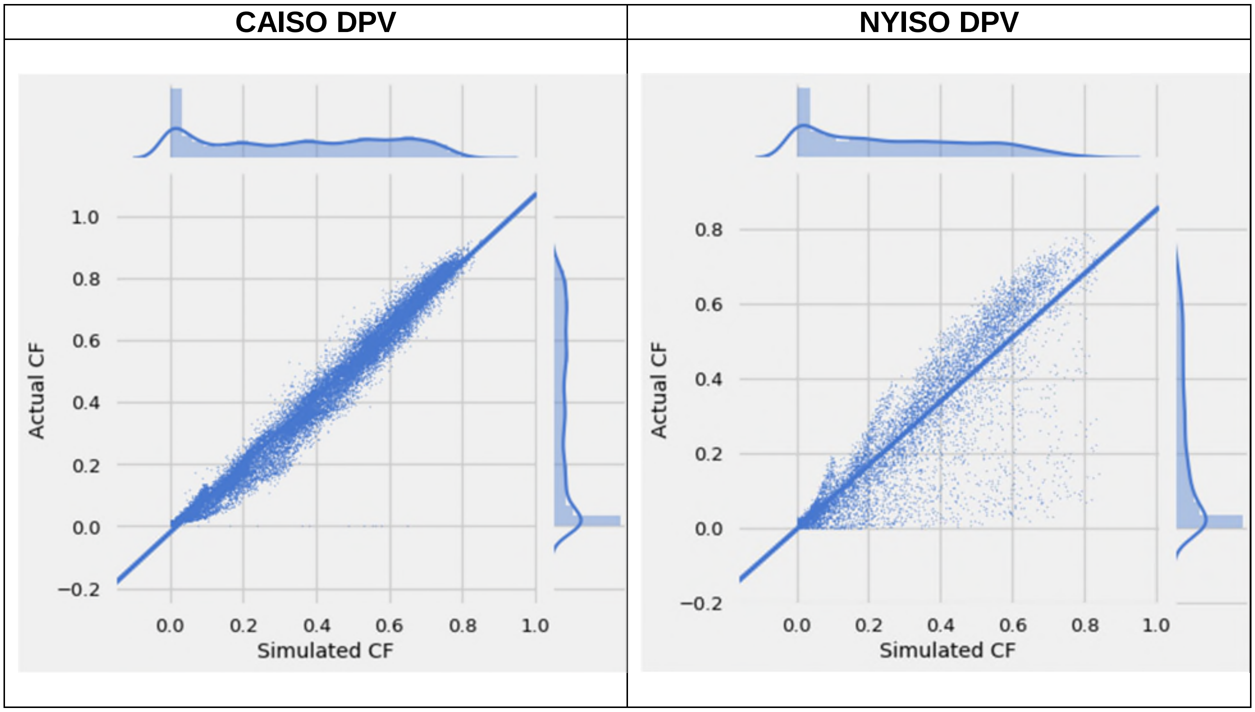
Plants not included in a balancing-authority aggregate hourly profile were only de-biased versus the EIA-reported monthly generation. Years 2012–2014 were de-biased versus annual, but not monthly, EIA-reported generation. The limitation to annual data for these years was due to errors in the monthly, but not annual, profile of generation.

Simulation Validation

We validated DPV and UPV solar profiles separately. First, we compare SAM-simulated DPV profiles with DPV profiles from other sources for two ISO market regions. Second, we compare plant-level hourly solar profiles provided by ERCOT to our de-biased simulated profiles for the same plants.

Simulated DPV generation is compared to generation records for the NEM capacity in the territory of the three major investor-owned utilities in California (California Solar Initiative)[35] and New York DPV generation data provided to us by the New York State Energy Research and Development Authority (NYSERDA). As seen in Note: CF is capacity factor.
Figure A-2, our CAISO DPV simulations achieve a very close fit. For NYISO DPV generation, however, we encounter many hours in which the simulated generation exceeds the reported DPV generation. Closer examination reveals that those hours occur primarily during the winter months, particularly after larger snow storms. It is our interpretation that actual DPV generation is reduced due to snow coverage on the panels, while SAM estimates high generation levels immediately after the sky clears. Similar mismatches that result in temporarily overestimated solar generation levels may be present for other raw SAM profiles.

35 https://www.californiadgstats.ca.gov/downloads/



Note: CF is capacity factor.

Figure A-2. Measured vs. Simulated Capacity Factor Data for DPV Capacity in CAISO and NYISO

To validate the UPV debiasing process we ran the process for utility-scale solar plants in the Electric Reliability Council of Texas (ERCOT) and compared the results to plant-level hourly generation provided by ERCOT. We tested two years, 2018 and 2016.

In 2018 there was significant curtailment, but in 2016 there was very little curtailment. Curtailment is accounted for in a step prior to the debiasing process. To adjust for curtailment we reduce modeled generation downwards to match recorded curtailment data during each hour. The curtailment data is recorded at the regional level (reported by CAISO and ERCOT), and we use a process that distributes regional curtailment down to plant-level based on local-nodal pricing (e.g., plants facing a price below $0/MWh are assumed to have greater curtailment than plants with positive prices).

We compare three modeled generation time series to hourly generation records for individual plants. The three time series are: (1) Raw modeled generation, (2) Modeled generation adjusted for curtailment, and (3) Modeled generation adjusted for curtailment and debiased. In 2016 we compare across 5 plants, in 2018 we compare records from 10 plants.

We see improvements to both biases and differences in hourly production levels (errors) with each adjustment to the modeled data. In other words, adjusting for curtailment reduces bias and error, but adjusting for curtailment and then employing the subsequent debiasing technique provides substantially greater reduction to bias, Figure A-3, and error, Figure A-4.

It was expected that the bias would be mostly removed after the debiasing process, but the size of the reduction to root mean square error (RSME) was unknown. The substantial reductions to RSME, in addition to the expected near elimination of bias, indicate that the debiasing process improves both the accuracy and the precision of the modeled plant-level generation time series.

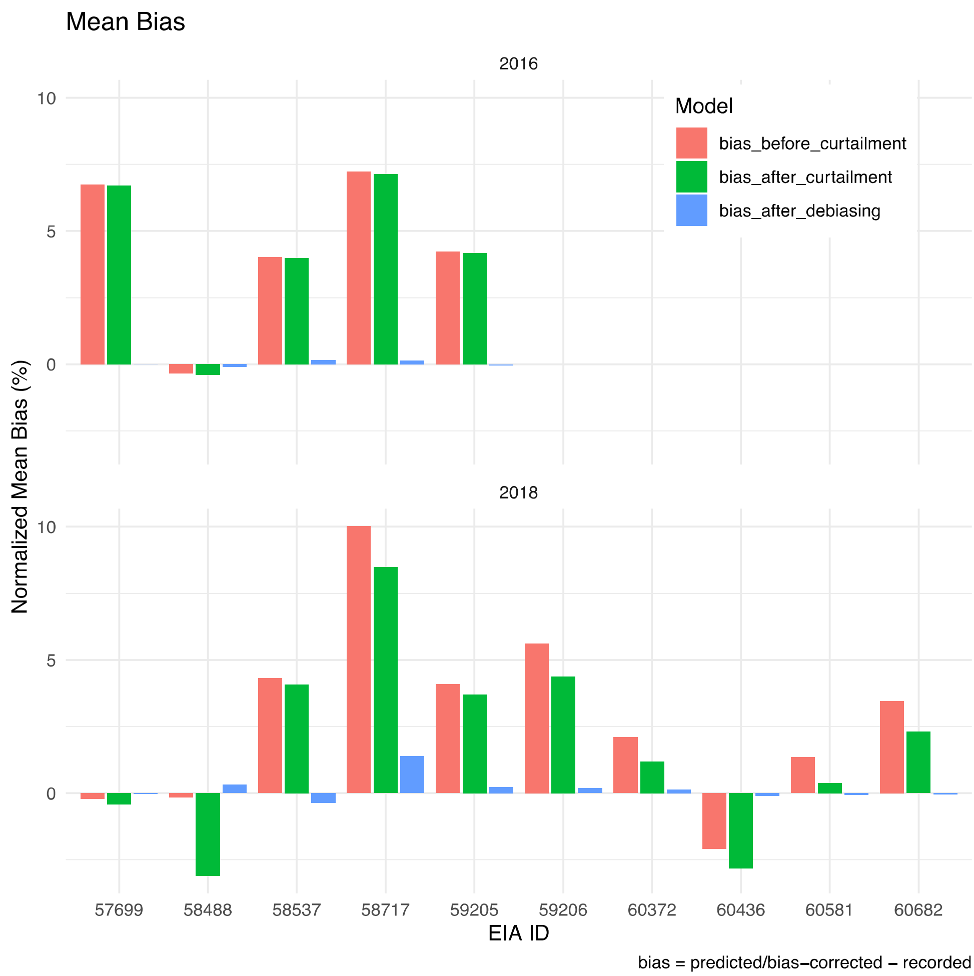


Figure A-3. De-biasing Process Brings Average Modeled PV Production Closer to Observed Average Production in ERCOT Plants

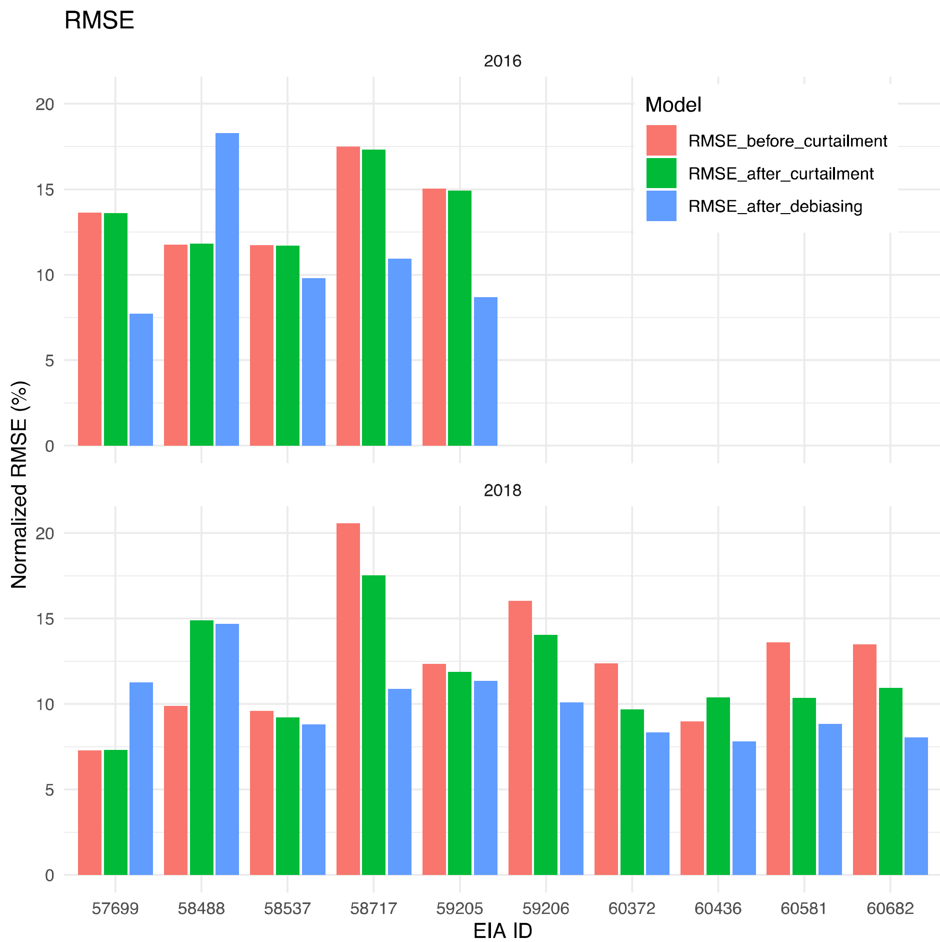


Figure A-4. De-biasing Moves Hourly Production Values Closer to Observed Hourly Plant Production in ERCOT

Appendix B. Capacity Credit Comparison to ISO/RTO Estimates

For SPP, MISO, PJM, NYISO, and ISO-NE, the ranges of various capacity credits from ISO documents are generally in line with the ranges of the capacity-weighted average capacity credit estimated using our hourly generation profile data (Figure B-1). The wide range of UPV values presented in SPP documents is driven by variation in capacity credit from one load-serving entity to another. Our UPV range is narrow because we use the SPP aggregate load profile, as opposed to individual load-serving entity profiles, to identify top load hours. PJM's wide range in values is primarily due to different solar technologies and estimation methods. The highest three estimates are based on PJM's assessment of average solar generation during peak times for three solar configurations: a ground-mounted tracking photovoltaic (PV) system (60%), a ground-mounted fixed-panel system (42%), and an "other than ground mounted" system (38%). The lowest individual estimate is based on PJM's estimated reduction in the forecasted peak load due to DPV systems (27%). In contrast to the relatively high capacity credit of UPV in ERCOT, one recent estimate by ERCOT staff of ERCOT's DPV capacity credit found it to be only 36% in summer and 8% in winter, because DPV's production decreases earlier in the evening owing to its more easterly location and lack of tracking (ERCOT 2019).

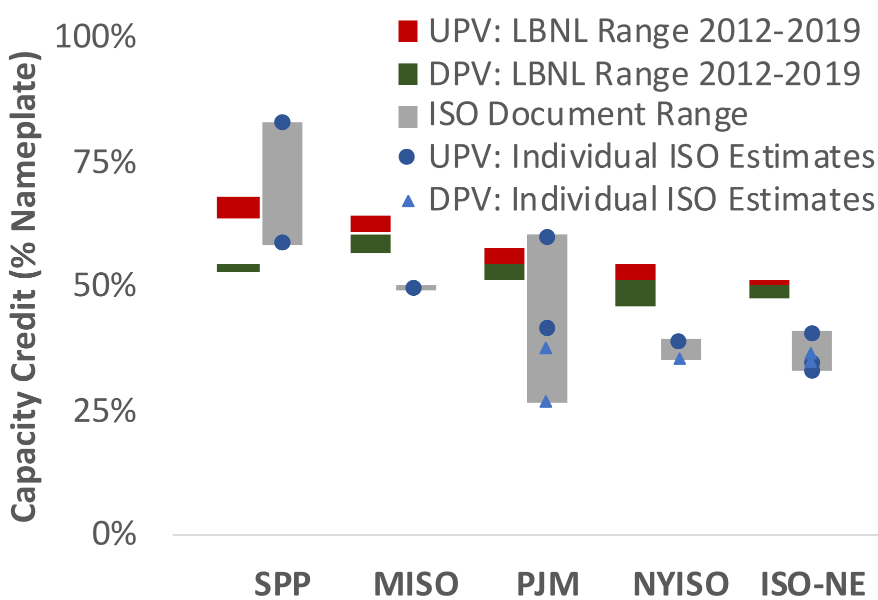


Figure B-1. Comparison of LBNL Estimated Capacity Credits to Levels Reported in ISO Documents

Appendix C. Solar Market Value Calculation Methods

The goal of the solar market value calculations is to estimate the marginal contribution of solar toward reliably balancing supply and demand at any point in time. To do this we use wholesale energy prices derived from security-constrained unit-commitment and economic dispatch and the production of solar to calculate the market revenue of solar, which we call its market value. Since wholesale prices vary across locations due to grid constraints, we pair individual solar plants with location-specific wholesale prices. The particular methods and assumptions differ between solar in organized wholesale markets and in non-ISO regions.

Our analysis focuses solely on the location-specific energy and capacity value of solar. We ignore the potential for additional revenue flowing from other sources, such as the sale of renewable energy credits or the provision of grid-support services via regulation and reserve markets. (Solar does not yet commonly participate in most formalized ancillary service markets). We also do not consider or include any other types of value that solar might provide, such as resilience, energy security, or any other environmental or social values that are not already internalized in wholesale energy and capacity markets (e.g., via permit prices for pollution allowances).

Organized Wholesale Markets

For each plant we calculate an energy value and a capacity value. Solar's energy value represents the product of real-time wholesale market energy prices and the coincident solar generation. Solar's capacity value represents solar's contribution to meeting resource adequacy requirements, and it is determined by the capacity credit (described in Section 3) and the coincident capacity prices. The energy and capacity values both represent the *marginal* system value of the last solar generator contributing to the market. For each plant, solar's total market value is simply the sum of its location-specific energy and capacity values, expressed on a pre-curtailment basis, according to the following formula (where the subscript h represents hours and T represents seasons or months, depending on the region):

$$Solar\ Value = \frac{\sum(Solar\ Postcurtailment\ Gen_h * Wholesale\ Energy\ Price_h) + \sum(Cap.Price_T * Cap.Credit_T * Nameplate\ Capacity)}{\sum Solar\ Precurtailment\ Gen_h}$$

The location-specific wholesale prices are based on matching a solar plant to an ISO wholesale pricing node.[36] We default to the node assigned to a UPV plant in ABB's Velocity Suite, if such an assignment exists. When no node is assigned, we substitute the nearest available node.

[36] We use real-time prices from more than 52,000 generator and load nodes: 7,561 in CAISO, 14,578 in ERCOT, 1,259 in ISO-NE, 2,768 in MISO, 571 in NYISO, 13,847 in PJM, 8,673 in SPP, and an additional 3,214 nodes for the non-ISO balancing authorities. Using nodal-level information captures pricing differences between central trading hubs and locations on the perimeter of each ISO that arise for example from transmission constraints.

The capacity value is based on the capacity price and the capacity credit. The capacity prices in the regions with organized capacity markets (MISO, PJM, NYISO, and ISO-NE) are based on the published forward capacity price for delivery in the year corresponding to solar production. Capacity prices in these markets vary with ISO zone. Two other ISO regions do not have organized capacity markets, but do require load serving entities to meet a resource adequacy obligation (CAISO and SPP). Capacity prices in CAISO are derived from annual reports summarizing bilateral capacity contract prices published by the California Public Utilities Commission (CPUC).[37] Capacity prices in SPP are estimated using short-term bilateral capacity contracts (monthly or annual) within the SPP region reported in FERC Electronic Quarterly Reports.

In addition to the energy and capacity value, we also estimate the incremental revenue that a solar plant could earn by participating in the day-ahead markets. Revenues when participating in day-ahead markets are based on day-ahead forecasts of solar and day-ahead prices with any imbalances settled at real-time prices. The difference between revenue when participating in the day-ahead market and only participating in the real-time market is called the “day-ahead premium”. We use historical solar forecasts from the North American Mesoscale Forecast System (NAM) for each individual solar plant. The day-ahead premium is calculated only for a subset of utility-scale solar plants with fully debiased data (624 plants in 2019). Results with the NAM forecast are bounded by a perfect forecast, where the day-ahead forecast exactly matches the actual production, and a naïve day-ahead persistence forecast, where the previous day’s observed solar is used as the forecast for the day-ahead forecast.

Non-ISO Utilities

Utilities outside of organized wholesale markets do not publish nodal electricity prices and market clearing prices for capacity. Because of differences in market structure, the process for estimating the historical value of solar in non-ISO regions differs from the approach used in the ISO-regions.

The first difference is that, except for utilities participating in the Western Energy Imbalance Market (EIM), we use only a single wholesale price for all PV within the utility to estimate energy value. When a utility is part of the EIM, we use prices from EIM node nearest to the UPV or DPV county aggregation. When the utility is not part of the EIM, we use wholesale prices from a nearby ISO-region (Table C-1). Comparison of the nearby wholesale market price to each utilities hourly marginal cost (or “system lambda”) reported in FERC Form 714 shows similar average annual levels. Because FPL is not near an ISO, we instead use FPL’s hourly system lambda, scaled on a daily basis by the average daily peak and off-peak index of bilateral trades in Florida.[38]

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[37] We use the 85th percentile monthly “System” capacity price reported by the CPUC.
[38] Daily peak and off-peak prices are reported in in the SNL Day-ahead Power Price index for the Florida Reliability Coordinating Council.

Table C-1. Energy Pricing Nodes Associated with Each Non-ISO Utility

Utility Name	Pricing Node (Market)
AZPS	PALOVRDE_5_N101 (CAISO)
NEVP	MEAD_5_N501(CAISO)
PACE	MONA_3_N501 (CAISO)
PNM	WILOWBCH_6_ND001 (CAISO)
PSCO	LAM345 (SPP)
TVA	TVA (MISO)
SOCO	SOCO (MISO)
DUK	SOUTHIMP (PJM)
CLPE	SOUTHIMP (PJM)
FPL	FPL system lambda scaled by peak and off-peak index of bilateral trades

Capacity value is calculated with the capacity credit for each balancing-authority and a capacity price based on recent bilateral capacity transactions reported in FERC EQRs. As described in Section 3, the capacity credit of solar in the non-ISO regions is the average solar production during the top 100 net load hours in the preceding three years. For 2014 and earlier we do not have the full three years of net load data from preceding years. In this case we limit our calculation to the average over the data that is available (e.g., the capacity credit in 2014 uses net load data from only 2012 and 2013). For the capacity price, we aggregate all transactions occurring in the utilities into three regions: non-California West (AZPS, NEVP, PACE, PNM, PSCO), Florida (FPL), and Southeast (TVA, SOCO, DUK, and CPLE). We aggregate across regions because of the relatively sparse number of capacity transactions specific to each individual utility. FERC EQR data is not available in 2012. Instead, we use SPP's estimate of the cost of new entry in 2012 for all regions. Capacity prices by year for each region are in Table C-2.

Table C-2. Bilateral Capacity Price Estimates for Each Region

Year	Non-CA West ($/kW-yr)	Southeast ($/kW-yr)	Florida ($/kW-yr)
2012	78	78	78
2013	63	47	101
2014	48	49	137
2015	52	66	137
2016	15	55	118
2017	15	61	95
2018	23	32	128
2019	45	46	107

Value of a Flat Block of Power

To estimate the value factor of solar, we divide the value of solar by the value of a flat block of power.

The value of a flat block of power includes both the energy value and the capacity value. In the ISO regions (and utilities participating in the Western EIM), the energy value of a flat block of power is the simple average of real-time prices across all hours of the year and all generator and load nodes within the ISO. The capacity value of a flat block of power at each node assumes a 100% capacity credit and, for the four organized forward capacity markets, uses the zonal capacity price associated with each node. We again use a simple average of capacity value across all nodes. In the non-ISO regions, there is no further geographic refinement, making the value of the flat block of power the average of the single energy price and the single capacity price.

Appendix D. Combustion Turbine Marginal Cost Assumptions

The marginal cost of a CT is calculated based on an assumed heat rate, CO_2 emission rate, natural gas price, and CO_2 emission price (Table D-1). Natural gas prices vary on a daily basis. Representative natural gas trading hubs were selected for each ISO based on ISO/RTO market monitor reports. A static natural gas price adder is added to the daily hub price to reflect transportation costs to generators. The gas price adder is calculated based on the differences between the average hub prices and the delivered cost of fuel to gas power plants within each ISO/RTO region, based on EIA data (accessed through the U.S. generator monthly production cost tables in ABB's Velocity Suite). Due to the recent changes in fuel data accessibility in ABB's Velocity Suite, the new set of price hubs are selected for the recent historical price data. The technological parameters, such as heat rate and emission rates, match assumptions made in the CAISO market monitor reports' net market revenue of new generation assets analysis section. The CO_2 emission prices for CAISO are from the California cap and trade program, as reported by the Climate Policy Initiative. For ISO-NE and NYISO, they are from the Regional Greenhouse Gas Initiative (RGGI) price.

Table D-1. Assumed Parameters for Calculating Marginal CT Cost

Market	Natural Gas Hub	Gas Price Adder ($/MMBtu)	CT Heat Rate (Btu/kWh)	CO_2 Emission Price	CO_2 Emission Rate (lb/MMBtu)
CAISO	SoCal CityGate and Border (2012 – 2017) ABB California North and South (2018 – 2019)	1.5	9,437	CA cap & trade	118
ERCOT	Houston Ship Channel (2012 – 2017) ABB Gulf Coast STX (2018 – 2019)	0.7	9,437	N/A	118
SPP	Panhandle (2012 – 2017) ABB TexOK (2018 – 2019)	0.7	9,437	N/A	118
MISO	Chicago Citygate (2012 – 2017) ABB Chicago Metro (2018 – 2019)	0.3	9,437	N/A	118
PJM	TETCO M3 (2012 – 2017) ABB Gulf Coast ETX (2018 – 2019)	0.7	9,437	N/A	118
ISO-NE	Algonquin Citygates	-0.3	9,437	RGGI	118

	(2012 – 2017) ABB New England (2018 – 2019)				
NYISO	Millennium and Iroquois Zone 2 (2012 – 2017) ABB New York Upstate, Long Island, and Niagara (2018 – 2019)	-1.0	9,437	RGGI	118

Appendix E. Illustrations of Solar Impact on Minimum Net Load and Maximum Ramp Rate

CAISO is the only market where the minimum net load is significantly lower than it would otherwise be without solar. Without solar, the minimum net load level in 2018 would occur in the middle of the night. With the addition of solar, however, the minimum net load shifts to the middle of the day and is much lower than the net load without solar (Figure E-1).

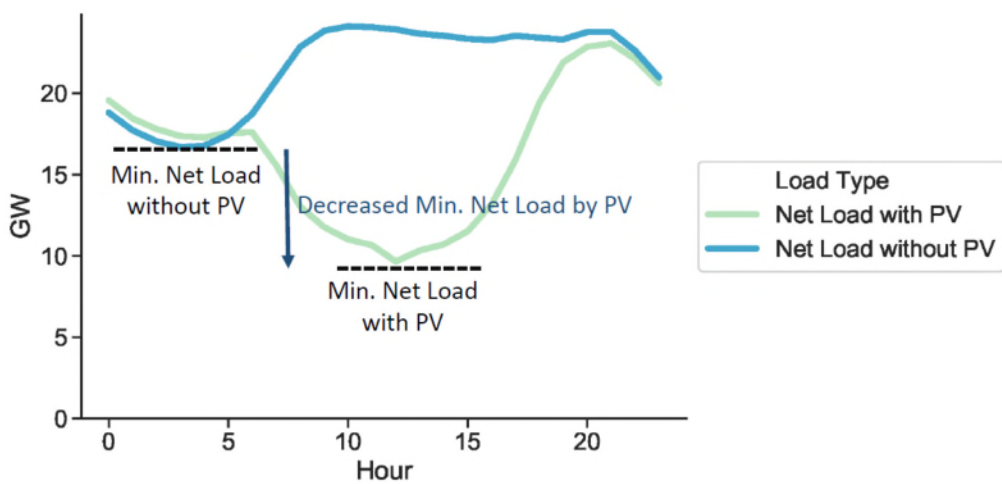


Figure E-1. Illustration of Minimum Net Load With and Without Solar in CAISO (2018)

In other markets, the growth in solar has decreased net load, but not enough to match the minimum net load level without solar. As a consequence, the level of minimum net load with or without solar continues to occur in the early morning hours at the same level. Growth of solar in ISO-NE is at the point where the minimum net load with solar during daytime is very close to the level of minimum net load in the early morning (Figure E-2).

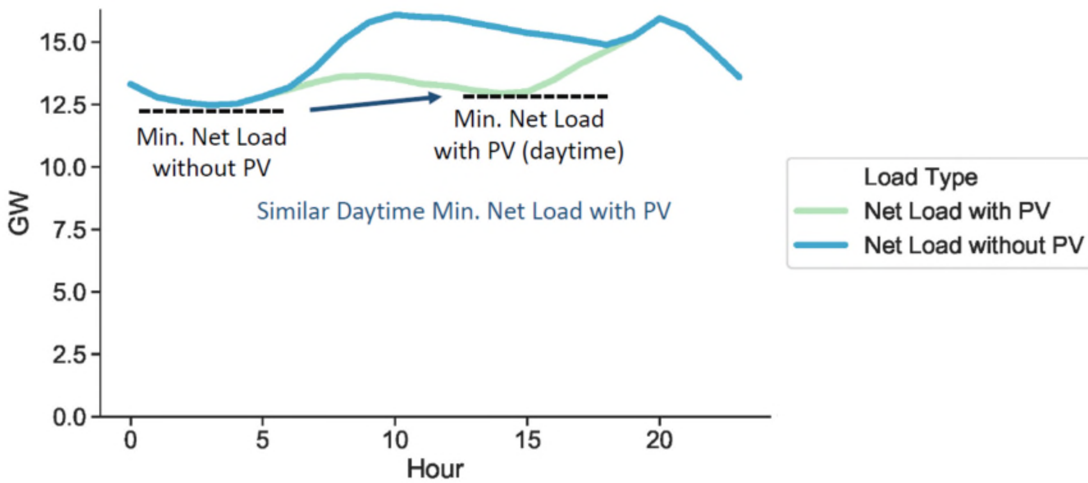


Figure E-2. Illustration of Minimum Net Load With and Without Solar in ISO-NE (2018)

For 2018, the maximum net load ramp rates in CAISO are greater with solar relative to the maximum net load ramp rates without solar (Figure E-3). Without solar, the maximum ramp rate would occur in the early morning hours during the early morning load pickup. With solar, however, the maximum ramp rate shifts to the late afternoon when the sun starts to set and load continues to be high.

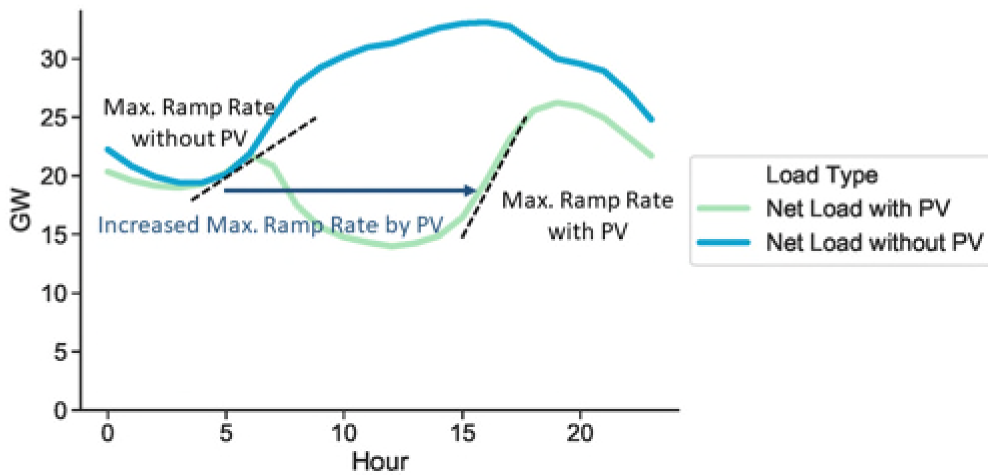


Figure E-3. Illustration of Maximum Ramp Rate With and Without Solar in CAISO (2018)

In contrast, the maximum net load ramp rates in ISO-NE occur in the early morning with and without solar (Figure E-4). In fact, the decrease in the morning net load due to solar means that the magnitude of the net load ramp rate with solar is slightly smaller than it is without solar.

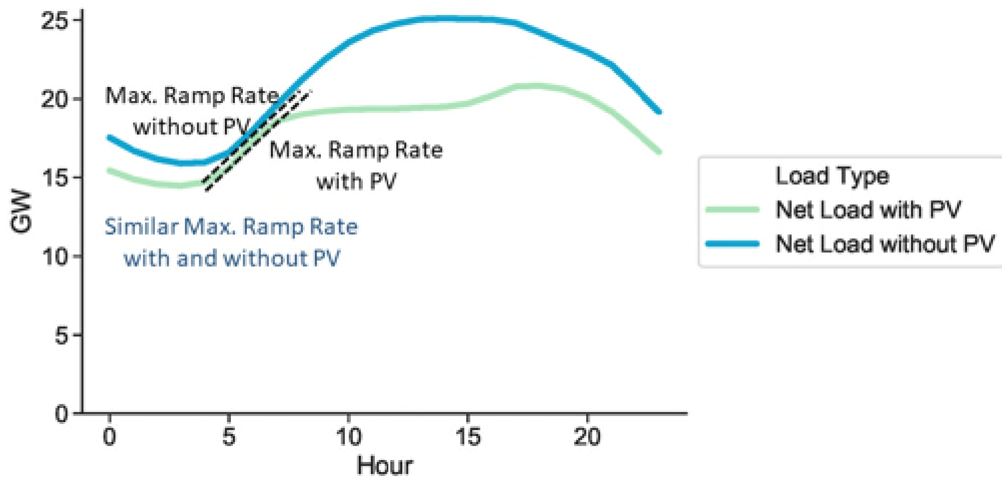


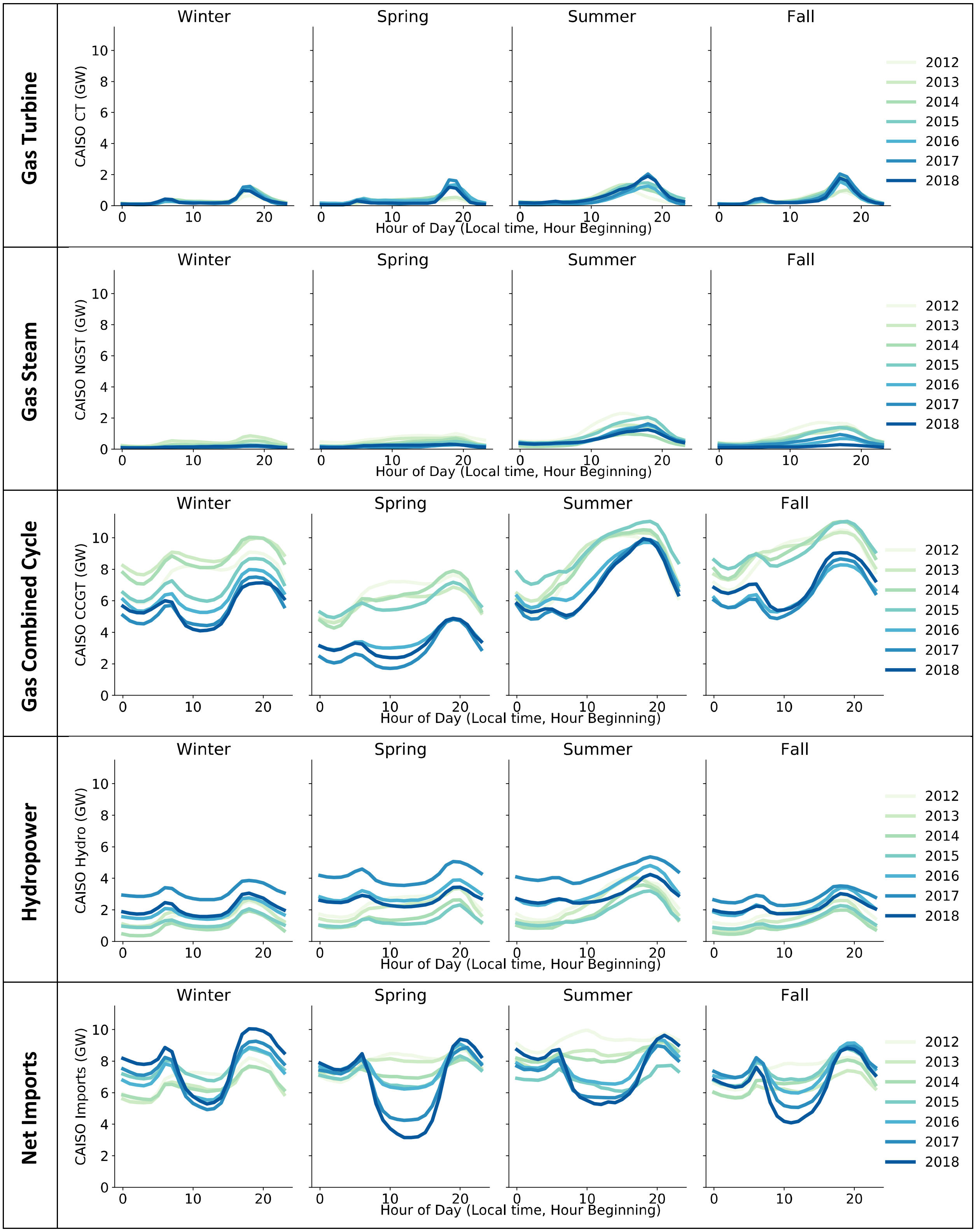
Figure E-4. Illustration of Maximum Ramp Rate With and Without Solar in ISO-NE (2018)

Appendix F. Solar Impact on Generation Patterns and Resources Providing Ramping in CAISO

As shown in Section 5, significant solar deployment leads to shifted net load patterns and increased ramping demands. In this appendix, we analyze how these two solar impacts affect the dispatch patterns of conventional generation in the form of CT, natural gas steam turbine (NGST), combined-cycle natural gas turbine (CCGT), nuclear, and hydropower generators as well as imports.[39] Consistent with other results from this section, we find that no region besides CAISO experienced significant changes in conventional generator dispatch patterns that appear related to solar between 2012 and 2018. In ISO-NE, while there was a slight drop in CCGT dispatch in the spring of 2018 that was outside of the historical range, the dispatch patterns were in line with historical patterns for all other seasons and generator types. ERCOT dispatch levels changed significantly over the 6 years, but those changes tracked most closely with load growth. For these reasons, the remainder of this subsection section focuses on CAISO dispatch patterns.

Figure F-1 plots changes in the dispatch profiles of different prime-mover technologies in the CAISO region. Over time, CTs operated more in the evening, while natural gas steam generation steadily decreased. The decreased steam generation was likely due to solar as explained below. Steam generation also shifted slightly from midday to evening, particularly in the summer. The CCGT dispatch pattern tracked changes in net load, moving toward the pronounced "duck curve" shape. The shift in total CCGT output is difficult to attribute to solar growth, because the downward shift in CCGT output inversely correlated with year-to-year changes in hydropower availability. As hydropower potential went up, CCGT output decreased, though the CCGT reductions were larger than the hydropower increases. Changes in hydropower dispatch patterns, especially in summer and fall, also followed changes in net load shape. Finally, the most obvious change in dispatch patterns occurred for net imports, which strongly correlated with changes in the net load curve. The composition of resources making up the imports in any hour is unknown, though imports increasingly have been from non-greenhouse-gas emitting resources (CARB 2019). Nuclear power dispatch patterns were stable and flat over time, likely owing to nuclear's relative ramping inflexibility and low marginal cost, compared to other generation resources.

[39] Hourly generation for the fossil fuel generators is from the U.S. Environmental Protection Agency's Continuous Emission Monitoring System. Hourly aggregate nuclear, imports, and hydropower profiles are from the respective market operators. While these were the base sources of data, we used the Velocity Suite data aggregator service from ABB to compile the data.



Gas Turbine
CAISO CT (GW)
Gas Steam
CAISO NGST (GW)
Gas Combined Cycle
CAISO CCGT (GW)
Hydropower
CAISO Hydro (GW)
Net Imports
CAISO Imports (GW)
Winter
Spring
Summer
Fall
Hour of Day (Local time, Hour Beginning)
2012
2013
2014
2015
2016
2017
2018

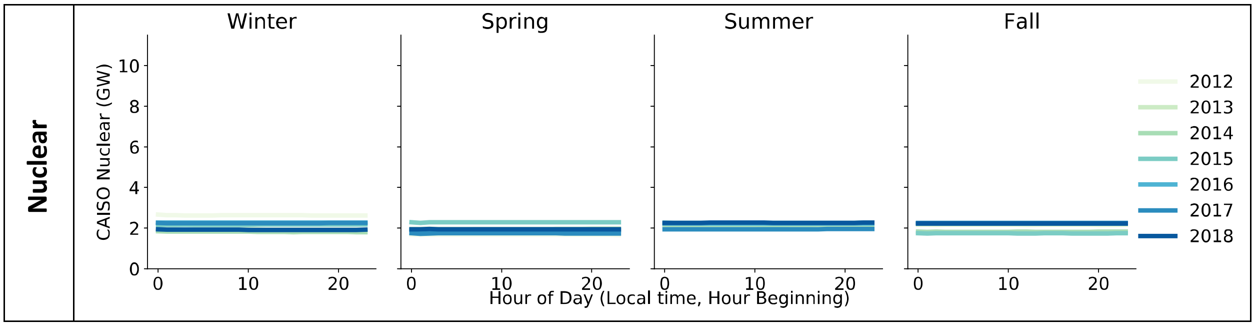


Figure F-1. Changing Dispatch Profiles of CAISO Generators

The above insights rely on visual inspection of changing dispatch patterns over a period marked by substantial solar growth in CAISO, but they do not control for other market parameters that could affect dispatch patterns. Building on the approach developed by Bushnell and Novan, we use an empirical regression model to estimate how much of the changes in dispatch patterns of various resources are due to solar growth (Bushnell and Novan 2018). As done in that paper, we control for natural gas prices, load levels, wind output, and a proxy for hydropower resource potential.[40]

The regression equation is presented below in Eq. 1. Our coefficient of interest is β_h, while all other variables are control parameters. Similar to Bushnell and Novan, we control for daily wind output, daily natural gas prices, hourly load levels, and a proxy for hydropower resource potential. We also include monthly fixed effects to control for seasonal shifts in supply that may be correlated with the seasonal patterns in wind and solar production.[41]

$$G_{h,t} = \alpha + \beta_{\mathrm{h}} Solar_d + \theta_{h,w} W_d + \theta_{h,ng} NG_d + \theta_{h,l} L_h + \theta_{h,Hy} Hy_m + \theta_{h,st} St_m + \gamma_m + \epsilon_t \text{ (Eq. 1)}$$

Where,

$G_{h,t}$ = hourly generation in MWh for a generator type, t

α = regression constant

β_{h} = average change in generator output due to a daily increase in solar output in MWh/GWh/day

$Solar_d$ = daily output of solar generation (including DPV and UPV) in GWh/day

W_d = daily output of wind generation in GWh/day

NG_d = daily natural gas spot price in \$/MMBtu

L_h = hourly load adjusted for DPV in MWh

[40] Natural gas prices are from ABB for the SoCal Citygate Hub. Load is adjusted to remove the impact of DPV in the same manner as discussed in Section 5.2. Hourly wind output is from CAISO. Finally, to calculate the hydropower proxy, we calculate a historical monthly moving average of precipitation in California with a 1-year window using data from the National Oceanic and Atmospheric Administration, accessed here: https://www.ncdc.noaa.gov/cag/statewide/time-series.

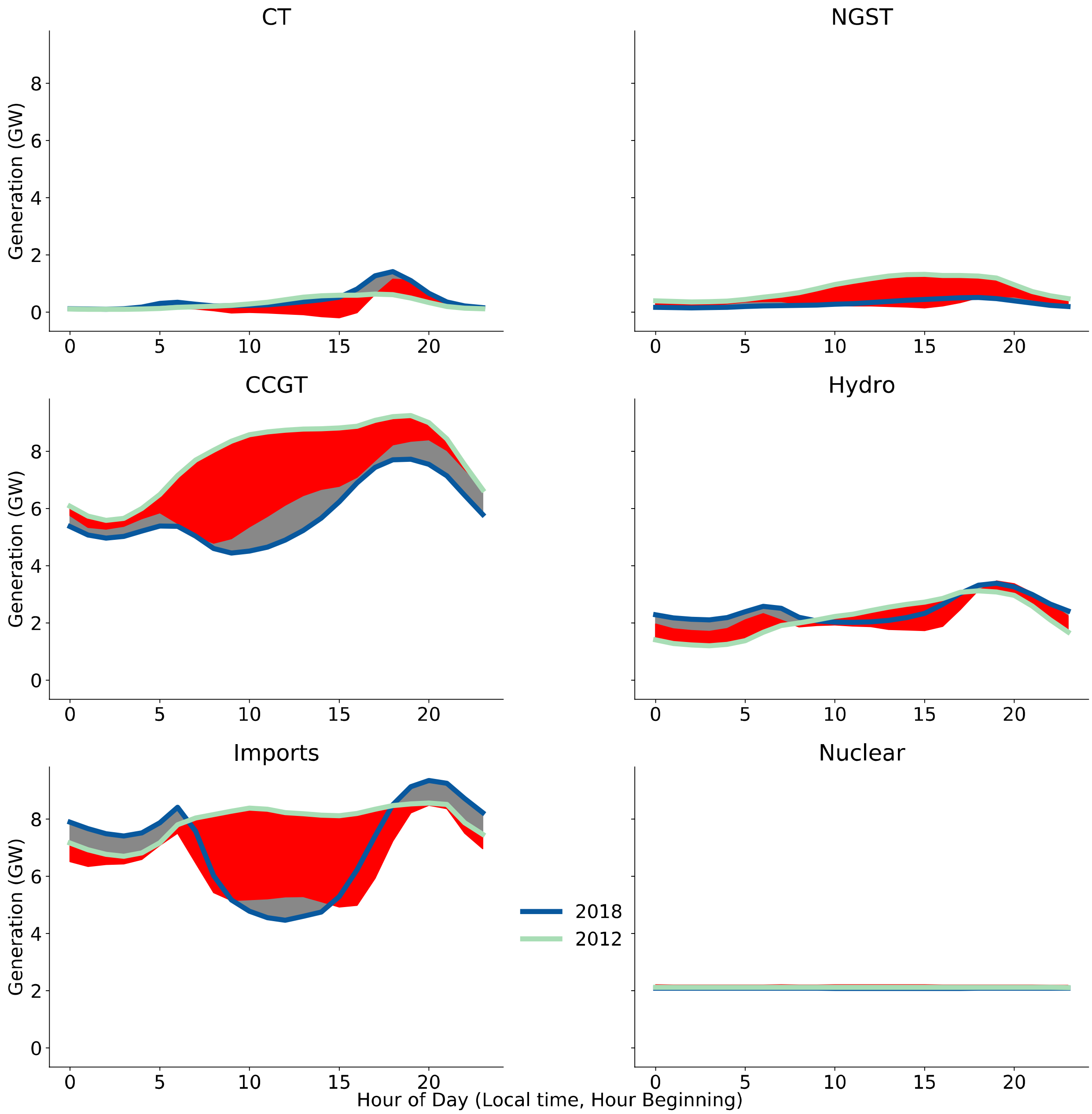
[41] Natural gas prices are from ABB for the SoCal Citygate Hub. Load is adjusted to remove the impact of DPV in the same manner as discussed in Section 5.2. Hourly wind output is from CAISO. Finally, to calculate the hydropower proxy, we calculate a historical monthly moving average of precipitation in California with a 1-year window using data from the National Oceanic and Atmospheric Administration, accessed here: https://www.ncdc.noaa.gov/cag/statewide/time-series.

Hy_m = monthly statewide precipitation proxy for hydropower potential in inches/month
St_m = monthly installed capacity of steam generators in MW
γ_m = monthly fixed effects
ϵ_h = random error for a given hour, h

We make two methodological changes from Bushnell and Novan, which we believe result in slight improvements on the empirical strategy. First, we incorporate DPV generation in our solar term to measure the impact of total solar deployment rather than just UPV deployment. Bushnell and Novan only have data on UPV generation. Second, due to concerns that NGST power plant retirements in California might have been the result of regulatory changes (e.g., once-through cooling rules), we additionally control for the installed generation capacity of NGSTs. This control ensures that our empirical model does not attribute the steam turbine retirements to growth in solar.[42]

Using this empirical estimation method, we identify the change in dispatch patterns between 2012 and 2018 due to solar, denoted as the red-shaded regions in Figure F-2. Because of all the changes that occurred between 2012 and 2018, the dispatch patterns shifted by the difference between the 2012 line and the 2018 line (gray-shaded areas). Had nothing changed between 2012 and 2018 except for the level of solar, the difference in the dispatch patterns would have instead been the red area. Overall, a significant portion of the overall changes in dispatch patterns is explained by solar growth, while only a small portion is explained by other factors controlled for in our empirical model, particularly for CCGTs and imports. Even after controlling for NGST retirements, increased solar still accounts for most of the decrease in NGST dispatch. Solar growth partially explains the increase in CT operation in the evening, while the remainder is likely explained by the decrease in NGST capacity.

[42] Over this same period, CT and CCGT capacity increased, though less than the reduction in NGST capacity. We tested inclusion of CT and CCGT capacity controls. We found that the results are not sensitive to the inclusion or exclusion of these controls, though the results are sensitive to the inclusion of the NGST capacity controls.



Note: The observed difference between 2012 and 2018 generation profiles is shaded in gray. The predicted change in generation profiles due to solar growth between 2012 and 2018 alone is shaded in red.

Figure F-2. Portion of Change in Observed Profiles Due to Solar Growth in CAISO, 2012–2018

We use a similar empirical analysis technique to assess how changes in net load ramps affect the dispatch patterns of conventional generators. The estimating equation to measure the effects of increased ramping on conventional dispatch is only slightly different from Eq. 1. Instead of the dependent variable representing the hourly output of conventional generation, the dependent variable represents the hourly ramp of conventional generators. Furthermore, the daily solar output variable turns into a control variable rather than the independent variable of interest. Our new independent variable of interest is the maximum hourly ramp in a given day. All of the other controls remain the same. See Eq. 2 for the mathematical representation of the model. With this approach, we measure which resources provide ramping capability in CAISO in response to the daily maximum net load ramp.

$$R_{h,t} = \alpha + \beta_{\mathrm{h}} Ramp_d + \theta_{h,s} S_d + \theta_{h,w} W_d + \theta_{h,ng} NG_d + \theta_{h,l} L_h + \theta_{h,Hy} Hy_m + \theta_{h,st} St_m + \gamma_m + \epsilon_t$$
(Eq. 2)

Where,
$R_{h,t}$ = hourly change in generation from previous hour in MWh for a generator type, t
α = regression constant
β_{h} = change in generator ramp due to an increase in the maximum hourly net load ramp in a day in MW/GW
$Ramp_d$ = maximum hourly ramping rate in a day in GWh
S_d = daily output of solar generation (including DPV and UPV) in GWh/day
W_d = daily output of wind generation in GWh/day
NG_d = daily natural gas spot price in \$/MMBtu
L_h = hourly load adjusted for DPV in MWh
Hy_m = monthly statewide precipitation proxy for hydropower potential in inches/month
St_m = monthly installed capacity of steam generators in MW
γ_m = monthly fixed effects
ϵ_h = random error for a given hour, h

In line with the results above, the greater the maximum ramp in a day, the more the imports respond by declining early in the day and then greatly increasing in the early evening at the time of the largest ramp up in the net load. The results are presented in Figure F-3. CCGTs also tend to ramp up more in the early evening hours in response to large ramp days, though the magnitude is less than it is for imports. Deployment of solar is clearly changing the dispatch patterns of CAISO generators and flexibility from imports plays a key role in managing the growing net load ramps. As mentioned in Section 5.3, the flexibility from imports has likely been enhanced by the Western Energy Imbalance Market. Growth in variable renewables across the utilities participating in the Western Energy Imbalance Market, however, may begin to limit the flexibility available from imports.

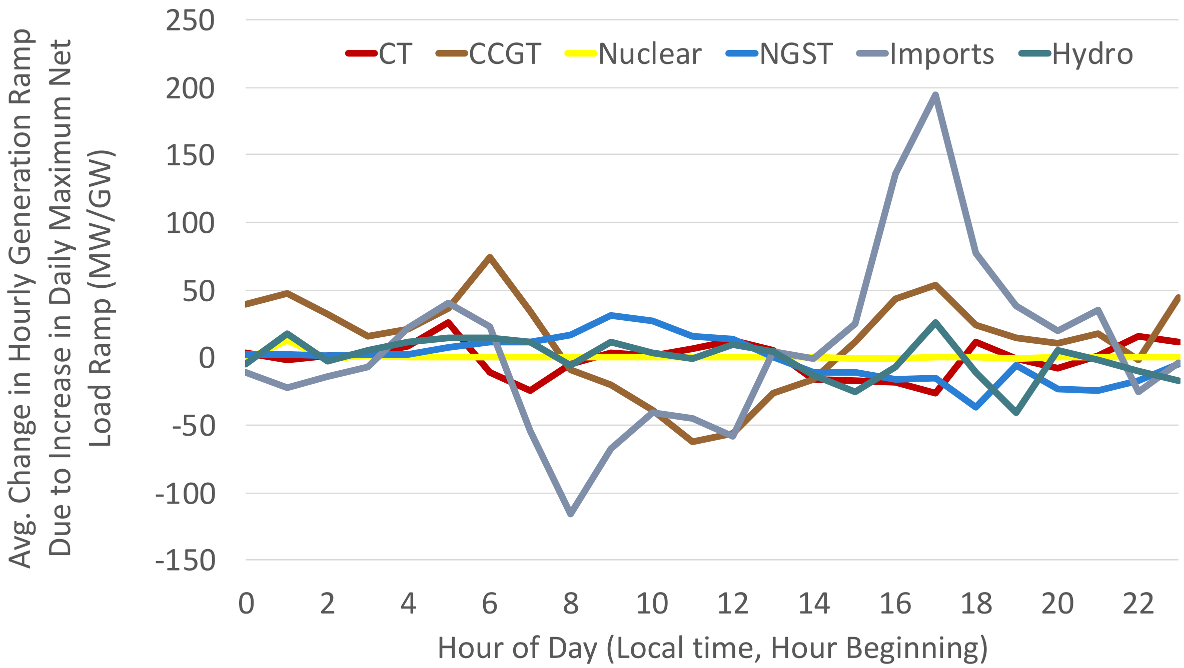


Figure F-3. Sensitivity of Generator Ramping to Maximum Daily Ramp in the Net Load in CAISO

Appendix G. Net Revenue Assumptions and Additional Results

Table G-1. Price Hub and Periods for Day-Ahead and Real-Time Prices

Market	Day-Ahead, Real-Time Locational Marginal Prices	Period
CAISO	SP15	2012–2019
ERCOT	North Hub	2012–2019
PJM	Western Hub	2012–2019
ISO-NE	Internal Hub	2012–2019

Table G-2. Conventional Generation Technology Parameters for Net Revenue Analysis

Technical Parameters	Unit	CT	CC	RICE	Coal	Nuclear
Minimum operating level	%	38	52	N/A	40	N/A
Capacity	MW	100	500	5	600	2,200
Heat rate	Btu/kWh	9,437	6,679	11,000	9,250	11,000
VO&M costs	$/MWh	0.25	1	0.15	4	3
CO_2 emission rate	lb/MMBtu	118	118	118	215	0
Startup cost	$/MW-start	20	40	N/A	60	N/A
Minimum up time	hours	2	4	N/A	8	N/A
Minimum down time	hours	1	1	N/A	1	N/A
Ramp rate	%/min	8	5	20	4	N/A

Table G-3. Storage Technology Parameters for Net Revenue Analysis

Technical Parameters	Unit	Value
Energy storage power	MW	8
Energy storage capacity	MWh	32
Maximum energy charge	MWh per hour	8
Maximum energy discharge	MWh per hour	8
Roundtrip efficiency	%	80
Regulation-up reserve capacity	% per hour	50
Regulation-down reserve capacity	% per hour	50

Table G-4. Demand Response Parameters for Net Revenue Analysis

Technical Parameters	Unit	Value
Minimum operating level	%	100
Capacity	MWh	100
VO&M costs	$/MWh	100

Max Up Time	hour	4
Max Starts/Year	unit	10

Table G-5. Ancillary Service Products Used in Net Revenue Analysis

Market	Ancillary Service
CAISO	Regulation up
	Regulation down
	Spinning
	Non-spinning
ISO-NE	Regulation
	Ten-minute synchronized
	Ten-minute non-synchronized
	Thirty-minute operating
ERCOT	Regulation up
	Regulation down
	Responsive
	Non-spinning
PJM	Regulation
	Synchronized
	Primary

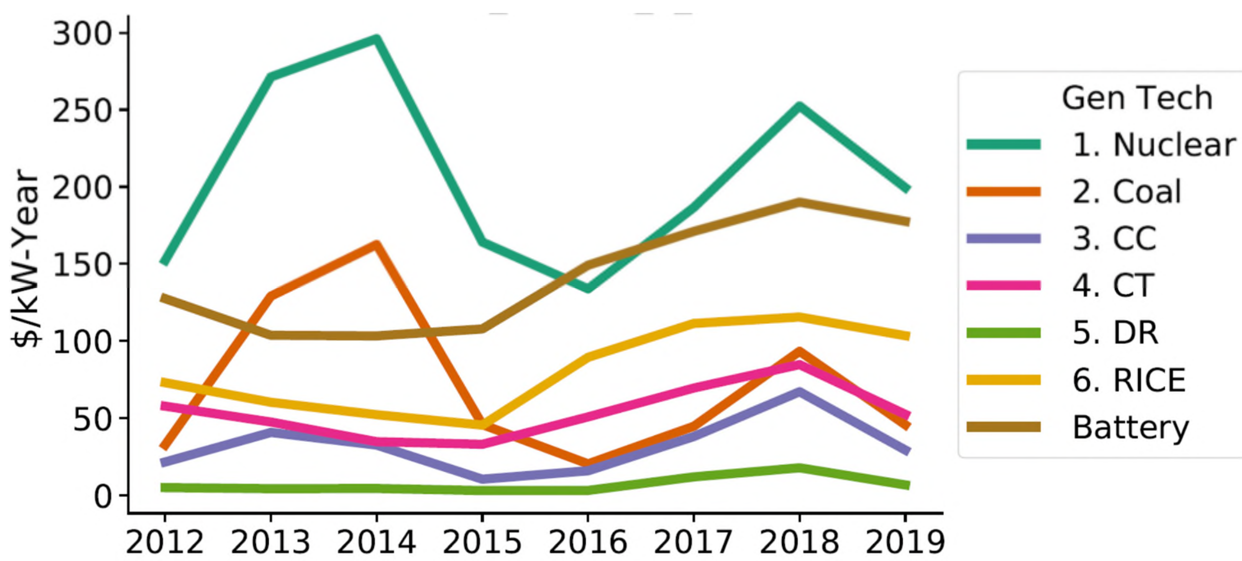


Figure G-1. Net Revenue from Energy and Ancillary Service Markets: CAISO

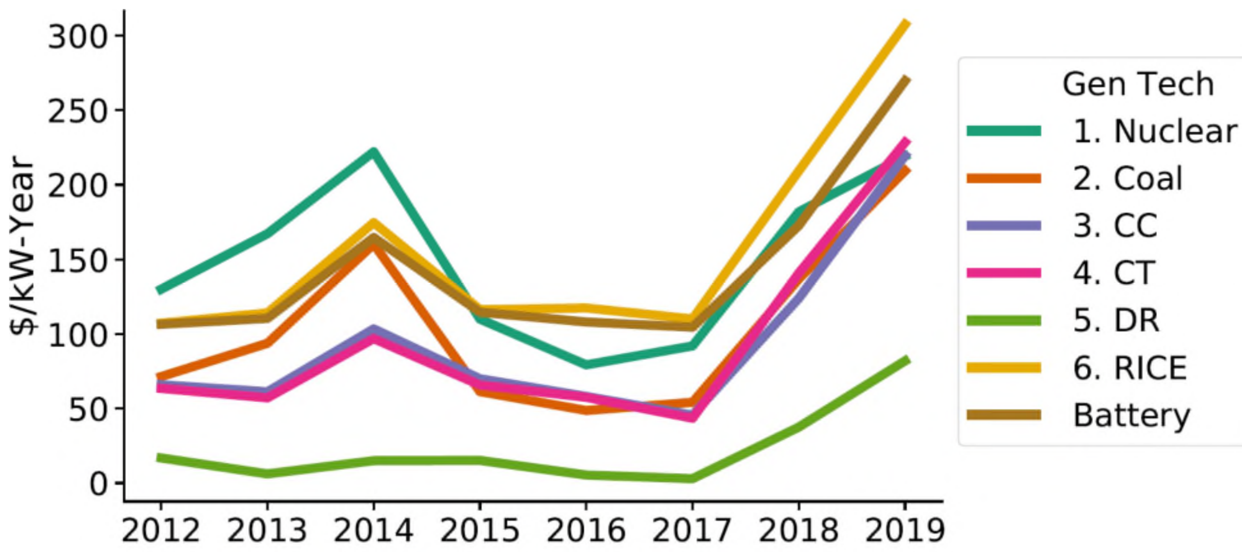


Figure G-2. Net Revenue from Energy and Ancillary Service Markets: ERCOT

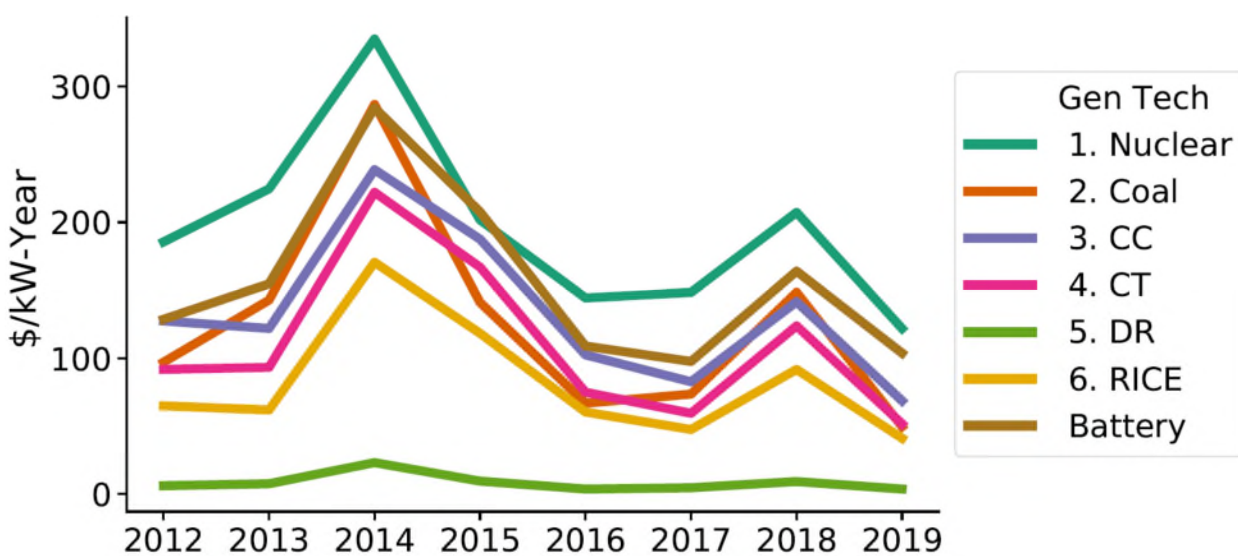


Figure G-3. Net Revenue from Energy and Ancillary Service Markets: PJM

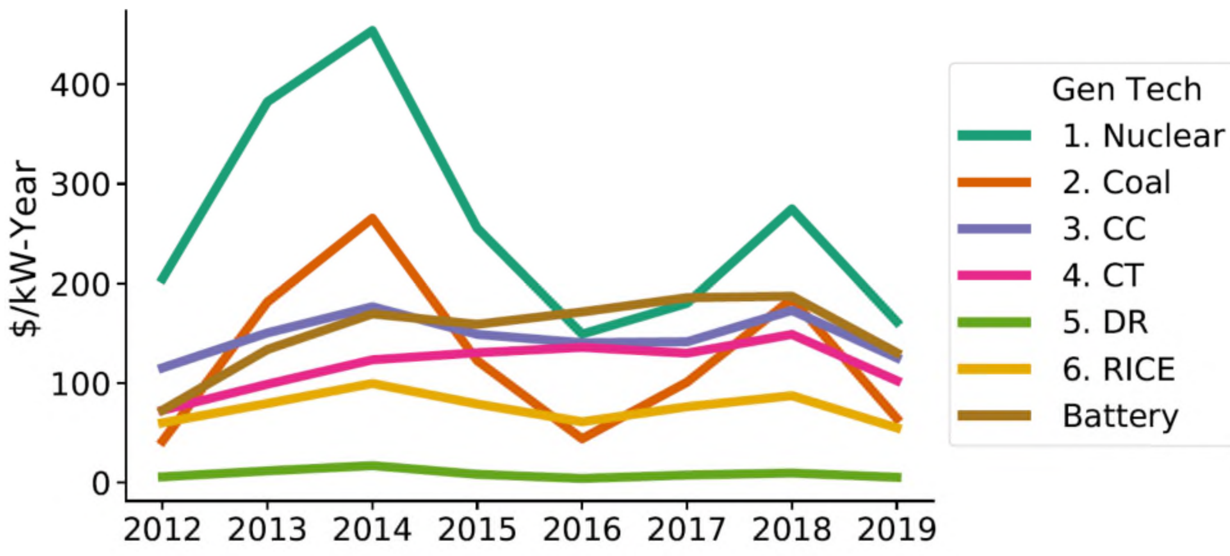


Figure G-4. Net Revenue from Energy and Ancillary Service Markets: ISO-NE