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Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California

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Environmental Energy Technologies Division

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Abstract

We estimate the long-run economic value of variable renewable generation with increasing penetration using a unique investment and dispatch model that captures long-run investment decisions while also incorporating detailed operational constraints and hourly time resolution over a full year. High time resolution and the incorporation of operational constraints are important for estimating the economic value of variable generation, as is the use of a modeling framework that accommodates new investment decisions. The model is herein applied with a case study that is loosely based on California in 2030. Increasing amounts of wind, photovoltaics (PV), and concentrating solar power (CSP) with and without thermal energy storage (TES) are added one at a time. The marginal economic value of these renewable energy sources is estimated and then decomposed into capacity value, energy value, day-ahead forecast error cost, and ancillary services. The marginal economic value, as defined here, is primarily based on the combination of avoided capital investment cost and avoided variable fuel and operations and maintenance costs from other power plants in the power system. Though the model only captures a subset of the benefits and costs of renewable energy, it nonetheless provides unique insights into how the value of that subset changes with technology and penetration level.

Specifically, in this case study implementation of the model, the marginal economic value of all three solar options is found to exceed the value of a flat-block of power (as well as wind energy) by $20–30/MWh at low penetration levels, largely due to the high capacity value of solar at low penetration. Because the value of CSP per unit of energy is found to be high with or without thermal energy storage at low penetration, we find little apparent incremental value to thermal storage at low solar penetration in the present case study analysis. The marginal economic value of PV and CSP without thermal storage is found to drop considerably (by more than $70/MWh) as the penetration of solar increases toward 30% on an energy basis. This is due primarily to a steep drop in capacity value followed by a decrease in energy value. In contrast, the value of CSP with thermal storage drops much less dramatically as penetration increases. As a result, at solar penetration levels above 10%, CSP with thermal storage is found to be considerably more valuable relative to PV and CSP without thermal storage. The marginal economic value of wind is found to be largely driven by energy value, and is lower than solar at low penetration. The marginal economic value of wind drops at a relatively slower rate with penetration, however. As a result, at high penetration, the value of wind can exceed the value of PV and CSP without thermal storage. Though some of these findings may be somewhat unique to the specific case study presented here, the results: (1) highlight the importance of an analysis framework that addresses long-term investment decisions as well as short-term dispatch and operational constraints, (2) can help inform long-term decisions about renewable energy procurement and supporting infrastructure, and (3) point to areas where further research is warranted.

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Acronyms

AS	Ancillary services
CAISO	California Independent System Operator
CCGT	Combined cycle gas turbine
CSP	Concentrating solar power
CT	Combustion turbine
DA	Day ahead
EUE	Expected Unserved Energy
LCOE	Levelized cost of energy
LOLP	Loss of load probability
LOLE	Loss of load expectation
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
O&M	Operations and maintence
PHS	Pumped hydro storage
PPA	Power purchase agreement
PTC	Production tax credit
PV	Photovoltaic
REC	Renewable energy credit
RPS	Renewables portfolio standard
RT	Real time
SAM	System Advisor Model
T&D	Transmission and distribution
TES	Thermal energy storage
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study
VG	Variable generation
VOLL	Value of lost load

1 Introduction

The variable and unpredictable nature of some renewable resources, in particular wind and solar, leads to challenges in making long-term decisions based on economics that differ from the challenges with the same for conventional generation. In order for decisions to be made on an economic basis, the costs of procuring variable renewables needs to be compared to the benefits of those renewables. The costs side of the equation considers metrics like the levelized cost of energy (LCOE) or the cost of a power purchase agreement (PPA) (Wiser and Bolinger, 2012; Barbose et al., 2012) and can also consider costs to expand transmission and distribution infrastructure (Holttinen et al., 2011; Mills et al., 2011, 2012). The benefits side, also called the "avoided costs" or the economic value, is just as important to consider since comparisons of generating technologies simply based on the relative generating cost of those technologies would be incomplete (Joskow, 2011; Borenstein, 2012). The benefits of variable renewables can include a wide range of factors including hedging against fossil fuel price fluctuation, reducing environmental impacts from other sources of electricity, and avoiding fuel, O&M and capital cost expenditures from operating other power plants. Renewable resources that are sited on the distribution system near electric loads have further potential benefits of reducing electrical losses and avoiding expenditures related to transmission and distribution (T&D) system infrastructure. The potential benefits depend on a wide range of factors including penetration level, generation profile, and network characteristics (Passey et al., 2011; Cossent et al., 2011).

To better understand the economic value of variable renewable generation (VG) and how it changes with increasing penetration, this paper only focuses on quantifying the benefits side of this equation and it further only focuses on a subset of the benefits. The subset of the benefits of VG considered here is based only on avoiding the capital investment cost and variable fuel and O&M costs from other power plants in a power system. These avoided costs are calculated while including operational constraints on conventional generators and the increased need for AS when adding VG to a power system. Furthermore, the economic value is the marginal economic value based on the change in benefits for a small change in the amount of VG at a particular penetration level (as opposed to the average economic value of all PV up to that penetration level). The analysis does not consider many other costs and impacts that may be important in some cases. The costs and impacts that are not considered in this analysis include environmental impacts, transmission and distribution costs or benefits, effects related to the lumpiness and irreversibility of investment decisions, and uncertainty in future fuel and investment capital costs. This paper presents a summary of a more detailed report that is available elsewhere (Mills and Wiser, 2012).

A growing body of literature provides significant insights into the long-run economic value of variable renewables considering long-term investment and retirement decisions with increasing penetration levels. This literature has varying levels of temporal and geographic resolution and is primarily focused on wind (Swider and Weber, 2007; De Jonghe et al., 2011). The Renewable Energy Deployment System (ReEDS) model developed by the National Renewable Energy Laboratory has been used to evaluate investments in scenarios with 20% wind energy (DOE, 2008) and 20% solar (Brinkman et al., 2011). ReEDS uses relatively low temporal resolution of 17 time-periods per year along with several statistical adjustments. Comparison of dispatch and investment results depending on the level of temporal resolution used in modeling high wind penetration scenarios indicates that temporal resolution can significantly impact estimates of the long-run economic value of wind (Nicolosi et al., 2010; Ludig et al., 2011).

Several recent studies highlight economic value of solar resources at low penetration (Borenstein, 2008; Lamont, 2008; Sioshansi and Denholm, 2010). Lamont (2008) also examines the value at high wind and PV penetration levels but does not consider the impact of detailed operational constraints on conventional power plants nor uncertainty in wind or PV generation forecasts.

2 Approach

This paper uses a long-run economic framework to evaluate the economic value of VG that accounts for changes in the mix of generation resources due to new generation investments and plant retirements for both technical reasons (i.e., when generators reach the end of an assumed technical service life) or for economic reasons (i.e., when generation is not profitable enough to cover its on-going fixed O&M costs). One VG technology at a time is added to the power system at various penetration levels and a new long-run equilibrium is found in the rest of the system for that given penetration of VG. The VG technologies include wind, PV, concentrating solar power without thermal storage (CSP_0) and CSP with six-hours of thermal energy storage (CSP_6). The new generation investment options include natural gas CCGTs and CTs, as well as coal, nuclear, and PHS. The investment framework is based largely on the idea that new investments in generation will occur up to the point that the short-run profits of that new generation (revenues less variable costs) are equal to the fixed investment and fixed O&M cost of that generation (Stoft, 2002). Because the system is in long-run equilibrium, the hourly market prices account for both the cost of energy and capacity, similar to actual "energy-only" power markets in the U.S. and elsewhere (Hogan, 2005).

Scarcity pricing is used in this model to signal periods where it is difficult to maintain balance between supply and demand. When insufficient generation is available to meet demand and AS targets the wholesale power prices in this model rise to predefined scarcity price levels. The scarcity price levels can be interpreted as the assumed loss of social welfare for missing AS targets and eventually for involuntary load shedding. In particular, the value of lost load is assumed to be \$10,000/MWh and the penalties for missing AS targets range from \$500/MWh for non-spinning reserves to \$2,000/MWh for regulation reserves.

A unique aspect of the long-run model used in this paper is that it incorporates significant detail important to power system operations and dispatch with variable renewables, including hourly generation and load profiles, unpredictability of variable renewables, AS requirements, and some of the important limitations of conventional thermal generators including part-load inefficiencies, minimum generation limits, ramp-rate limits, and start-up costs. The operational detail is simplified through committing and dispatching vintages of generation as a fleet rather than dispatching individual generation plants, an approach used elsewhere in the literature (Müsgens, 2006; Müsgens and Neuhoff, 2006). Day-ahead forecasts are used to make binding commitment decisions for all thermal generation except combustion turbines (CTs). The CTs are assumed to have short enough start-up times to be able to be committed in real-time. Day-ahead prices are generated using the day-ahead forecasts of VG while real-time prices are based on the actual VG. Day-ahead load forecast errors are ignored.

The investment decisions are similarly simplified by assuming that investments can occur in continuous amounts rather than discrete individual generation plants.

3 Case Study

This long-run model is applied to a case study that loosely matches characteristics of California in terms of generation profiles for VG, existing generation capacity, and the hourly load profile in 2030. Fossil-fuel fired generation parameters and constraints (e.g., variable O&M costs, the cost of fuel consumed just to have the plant online, the marginal variable fuel cost associated with producing energy, start-up costs, limits on how much generation can ramp from one hour to the next, and limits on the minimum generation limit when generation is online) are largely derived from observed operational characteristics of thermal generation in the WECC region, averaged over generators within the same vintage. Aside from fossil-fuel fired generation, the existing generation modeled in California includes geothermal, hydropower, and PHS. Fossil-fuel prices are based on the fuel prices in 2030 in the EIA's Annual Energy Outlook 2011 reference case forecast (EIA, 2011).

For each VG technology, the VG penetration is increased from a case with nearly no VG up to 30% or 40% penetration measured on an energy basis. The amount of VG included in each case is defined by the scenario and is not a result of an overall economic optimization. The actual generation profiles for the VG resources in each scenarios were selected from the resources identified in the Western Renewable Energy Zone

Initiative (WREZ) (Pletka and Finn, 2009). The resources were picked by ranking all of the WREZ resources by their relative economic attractiveness[1] to load zones in California and then selecting the most attractive resources of the type of VG being considered up to the desired penetration level. For comparison, similar cases were evaluated where the variable and imperfectly forecastable VG generation profile was replaced with the generation profile of an energy-equivalent flat block of power.

Hourly PV generation profiles were calculated using the NREL System Advisor Model (SAM) with solar insolation data from the National Solar Resource Database that is derived from historic satellite images. The PV data are based on single-axis tracking PV that is tilted at an angle of the PV site latitude. Hourly wind generation, day-ahead solar and wind forecasts are all from the dataset developed for the Western Wind and Solar Integration Study (WWSIS) (Piwko et al., 2010). For CSP the insolation data are converted into thermal heat generation in the solar field using SAM. The CSP plant is then dispatched within the dispatch model used in this analysis based on a method similar to (Sioshansi and Denholm, 2010).

Aside from the reference case, four sensitivity cases are evaluated to show the relative importance of major operational constraints, an increase in the cost of CO_2 emissions, reductions in the cost of resources that provide capacity (i.e., CTs), and assumptions about the retirement of existing thermal generation.

4 Results

The marginal economic value of wind, PV and CSP with increasing penetration of each variable energy resource in California is first explored by showing the total non-VG investment and the dispatch results for both VG and non-VG resources, including the implied capacity credit, changes in energy generation, emissions and curtailment. Variable generation profiles and the hourly prices for energy and ancillary services are then used to estimate the marginal economic value of variable generation. This marginal economic value is decomposed into capacity value, energy value, day-ahead forecast error, and ancillary service costs to show which factors contribute the most to changes in the marginal economic value with increasing penetration. Finally, sensitivity cases are used to explore how the marginal economic value would change for a system without flexibility constraints, with higher energy costs (by adding a carbon price), with lower capacity costs, and without retirement of currently existing generation. Future research will consider strategies to stem the decrease in the economic value of VG at high penetration such as price responsive demand, more flexible thermal generation, and lower-cost bulk-power storage (lower cost than the assumed cost of PHS in this paper).

4.1 Investment and Dispatch Impacts

4.1.1 Nameplate Capacity of Generation

Adding VG to a power system decreases the amount of new non-VG capacity that is economic to add in 2030 relative to a scenario with no VG capacity. The amount of non-VG capacity that is built in the present framework is based on economic considerations: new generation resources are only added if the

[1] Specifically, the resources were ranked by the adjusted delivered cost estimated in the WREZ Peer Analysis Tool (`http://www.westgov.org/rtep/220-wrez-transmission-model-page`). This metric includes the bus-bar cost of the resource, a pro-rata share of a new 500 kV transmission line between the resource hub and the load zone, and a simplified estimate of the market value of the power to the load zone.

Text Box 1. Comparison of variable generation to flat block of power

Irrespective of the generation profile, adding significant amounts of any type of new generation to a power system to some degree changes dispatch and investment decisions in the rest of the power system. A case was run using a resource that has a flat generation profile over the entire year in order to better highlight changes in the marginal economic value of variable generation that are due in part to factors like temporal generation profiles, variability, and uncertainty in contrast to changes that are associated with simply adding significant amounts of generation from a new resource. This resource is referred to as a flat block throughout the Results section. The flat block is only meant to provide an idealized comparison; it is not meant to characterize any particular alternative resource.

The total nameplate capacity and the total annual energy production from the resources in the power market with increasing penetration of a flat block are shown in Figure 1. From 0% to 30% penetration adding a unit of nameplate capacity from the flat block offsets the need to build new combined cycle natural gas plants. At 40% penetration of a flat block, however, no new combined cycle plants need to be built and none of the existing thermal generation finds it economically attractive to retire for economic reasons. At this penetration, then, the total nameplate capacity slightly exceeds the total nameplate capacity between 0% to 30% penetration of the flat block.

Increasing penetration of the flat block offsets energy generated by combined cycle natural gas plants. Even at high penetration adding power from a flat block does not displace any generation from the small amount of incumbent coal in this market in 2030.

Additional results based on increasing the penetration of a flat block are included throughout the Results section along with comparable results for the four variable generation technologies.

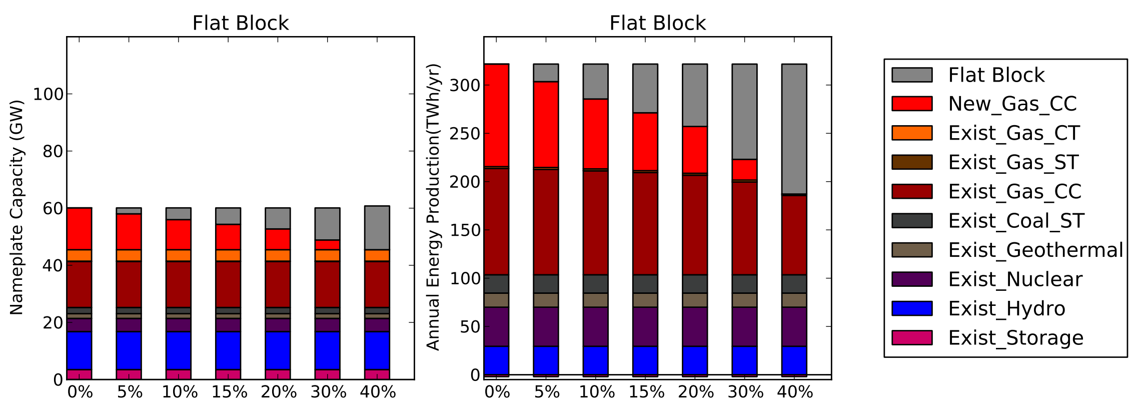


Figure 1: Total nameplate capacity and total energy generation from different resources with increasing penetration of a flat block of power.

short-run profits earned by the resource can cover the annualized investment cost and fixed O&M cost. The resulting investments, however, are coupled with indicators of the reliability of the system. Across all of the penetration scenarios and VG technologies, for example, the percentage of time with wholesale power prices that equal or exceed \$500/MWh[2] is always below 1% of the year, Table 1.[3] If too little generation were built to cover peak demand and AS in cases with high penetration of VG then the percentage of time with price spikes would increase and the short-run profits of conventional generation would increase. The fact that the amount of time with price spikes stays relatively constant with increasing VG, suggests that just as sufficient generation capacity is being added in the case without VG as is being added in the cases with increasing VG penetration. Interestingly, the frequency of price spikes decreases with very high penetrations of CSP_6 presumably because the overall system shifts towards being energy constrained rather than capacity constrained as is explained throughout the Results section.

Table 1: Percentage of the year with energy prices that equal or exceed \$500/MWh with increasing penetration of VG.

	Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	0.8%	n/a	0.8%	0.8%	0.8%	0.8%	0.8%	0.7%
Wind	0.8%	n/a	0.7%	0.7%	0.7%	0.8%	0.8%	0.8%
PV	0.8%	0.8%	0.8%	0.8%	0.8%	0.7%	0.7%	n/a
CSP0	0.8%	0.8%	0.8%	0.8%	0.7%	0.6%	0.6%	n/a
CSP6	0.8%	0.8%	0.7%	0.6%	0.6%	0.3%	0.0%	n/a

Additionally, the amount of involuntary load shedding as a percentage of the total load remains below 0.01% with increasing penetration of VG, Table 2. If too little generation were built or if the system did not have sufficient flexibility to manage higher penetrations of VG then the amount of involuntary load shedding would substantially increase. That the amount of involuntary load shedding remains below 0.01% even with high VG penetration also demonstrates that sufficient generation is being built by the model and that the system has sufficient flexibility to manage VG. The amount that the involuntary load shedding does increase in cases with high VG penetration, particularly high wind, can be explained in part due to the steeper net-load duration curve at the very high net-load levels with high VG penetration relative to the steepness of the load duration curve at very high load levels without VG. When the cost of new capacity is roughly \$200/kW-yr and the value of lost load is assumed to be \$10,000/MWh, it is more economic to involuntarily shed load for any net-load level that occurs less than roughly 20 hours per year than it is to build new capacity just to meet those very infrequent high net-load events. Because the net-load duration curve is slightly steeper more of the net-load occurs for less than 20 hours per year than the amount of load that occurs for less than 20 hours per year without VG.[4]

[2]\$500/MWh is the lowest scarcity price level that indicates that AS targets are not being met.

[3]The percentage of time that wholesale prices equal or exceed \$500/MWh is based on load and generation data from only one year. In a reliability focused planning study where it is important to ensure an absolute level of reliability (rather than maintaining a relative level of reliability in this study) it would be important to include more years of data with different load and generation shapes. In addition, factors like scheduled maintenance and forced outage rates would need to be considered. These issues are less important for this study since the results are driven primarily by maintaining a relative level of reliability rather than reaching an absolute reliability target.

[4]Whereas the number of hours of the year with price spikes in Table 1 is a proxy for the loss of load expectation (LOLE) that would be estimated in a reliability analysis, the percentage of unmet load in Table 2 is a proxy for the expected unserved

Table 2: Percentage of the total annual load that is not met during periods with prices that exceed the value of lost load ($10,000/MWh).

	Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	0.004%	n/a	0.004%	0.004%	0.004%	0.004%	0.004%	0.002%
Wind	0.004%	n/a	0.005%	0.004%	0.005%	0.006%	0.008%	0.009%
PV	0.004%	0.002%	0.003%	0.004%	0.006%	0.007%	0.006%	n/a
CSP_0	0.004%	0.002%	0.003%	0.005%	0.006%	0.006%	0.006%	n/a
CSP_6	0.004%	0.004%	0.003%	0.002%	0.001%	0.000%	0.000%	n/a

At 40% penetration of a flat block the amount of involuntary load shedding falls because new capacity no longer needs to be built and therefore the periods with prices high enough to trigger involuntary load shedding are not needed to induce new investments. Instead, the prices only need to rise high enough to ensure that incumbent generation does not retire for economic reasons. As with the frequency of high prices, the amount of involuntary load shedding decreases with high CSP_6 penetration as the overall system shifts towards being energy constrained rather than capacity constrained.

The resulting amount of new conventional generation that is built, the amount of incumbent conventional capacity, and the nameplate capacity of VG are shown for each penetration level in Figure 2.

In all cases (excluding the sensitivity cases explored later) the only new non-VG investments are in new CCGT resources under the assumptions used in this study. While the short-run profit of new CCGT resources was approximately equal to the investment cost of new CCGTs, the short-run profits of new coal, new nuclear, and new PHS resources were far below their annualized investment cost, Table 3. Major changes to fuel costs or investment costs would likely be needed to increase investments in these other technologies.

Similarly, no new CTs were built in addition to the existing incumbent CTs. The short-run profit of the CTs however, was commonly close to or above 90% of the annualized fixed investment cost of new CTs, or only $20/kW-yr or less below the assumed annualized investment cost of CTs. Even though the CCGTs were assumed to have fixed investment and O&M costs that were $10/kW-yr more than that of the CTs, the CCGTs were slightly more economically attractive because the CCGTs earned greater short-run profit in non-scarcity hours due to their relatively high efficiency in comparison to the CTs (they both earned roughly the same amount during scarcity hours). That being said, CTs become increasingly more attractive with increasing penetration of VG (except in the case of increasing CSP_6) due to the decreased amount of energy needed from CCGTs and the increased value of CT flexibility. Relatively modest reductions in the assumed investment cost of CTs relative to CCGTs would therefore lead to new CTs substituting for a portion of the CCGTs that are built, as is found in the sensitivity studies in Section 4.4. Similarly, consideration of factors such as the shorter lead time for construction and smaller size of individual units, factors not considered in this analysis, would tend to favor new CTs instead of new CCGTs. Furthermore, the relatively high amount of flexibility from the incumbent CTs, hydro, and pumped hydro storage in California all contribute significant flexibility to the system that would otherwise require new CTs in regions that lack substantial flexibility in the incumbent generation. Given the relatively small difference in the gap between the short-run

energy (EUE), a different reliability metric. As a result, these results suggest that even if the LOLE calculated in a reliability study were expected to remain constant across these scenarios, the EUE calculated in a reliability study would be expected to slightly increase with increasing penetration of variable generation.

profit and fixed cost of CTs relative to the gap for CCGTs it is important that CTs are considered in more detail in studies that would guide actual procurement processes.

Table 3: Short-run profit of investment options as a percentage of annualized fixed cost with and without 20% penetration of VG in 2030.

Investment Option	CCGT	CT	Coal	Nuclear	PHS
Fixed Cost ($/kW-r)	203	194	494	950	706
VG Technology	Short-run Profit as Percentage of Fixed Cost (%)				
0% VG	100%	88%	76%	51%	28%
20% Flat Block	100%	88%	76%	51%	28%
20% Wind	100%	94%	76%	51%	31%
20% PV	100%	95%	76%	51%	34%
20% CSP_0	100%	98%	74%	49%	36%
20% CSP_6	99%	68%	75%	51%	8%

As VG penetration increases, the total nameplate capacity of the combintation non-VG and VG resources increases above the nameplate capacity of non-VG resources alone in the 0% VG case. The increase in total nameplate capacity of the combintation of non-VG and VG resources is particularly evident in the cases with wind, PV, and CSP_0. This reflects the relatively low capacity factor of these resources and their relatively low ability to offset new investments in non-VG capacity especially at high penetration levels. Despite the increase in the combination of VG and non-VG nameplate capacity, in all cases the amount of non-VG capacity alone actually decreases with increasing VG penetration due to reductions in the amount of new CCGTs that are built. No penetration levels showed an increase in the nameplate capacity of non-VG capacity relative to the 0% VG case, indicating that VG at all penetration levels had some ability to offset new investments in non-VG capacity. In addition, all incumbent capacity in 2030 that was not retired for technical reasons found it to be economically attractive to stay in the power market in 2030. In other words, the short-run profit of incumbent generation always exceeded the assumed fixed O&M cost required to continue to operate the incumbent resources.

The effectiveness of VG in reducing the amount of non-VG capacity that is needed with increasing penetration differed between technologies. PV and CSP_0 were more effective at reducing the non-VG capacity at low penetration, but lost effectiveness at higher penetration levels. Wind only slightly reduces the amount of non-VG capacity that is built, but wind continues to displace a small amount of non-VG capacity even at higher wind penetrations. CSP_6 was very effective at reducing non-VG capacity at both high and low penetration levels.

The effectiveness of VG in reducing the amount of new non-VG nameplate capacity that is built can be more easily observed through calculating the implied marginal capacity credit of VG. The implied marginal capacity credit (hereafter called the capacity credit) is calculated as the incremental reduction in non-VG nameplate capacity per unit of additional VG nameplate capacity added between two different penetration levels. The capacity credit between two low penetration cases (0% and 5% penetration) and between two high penetration cases (15% and 20% penetration) is shown in Table 4. The increase in total (VG and

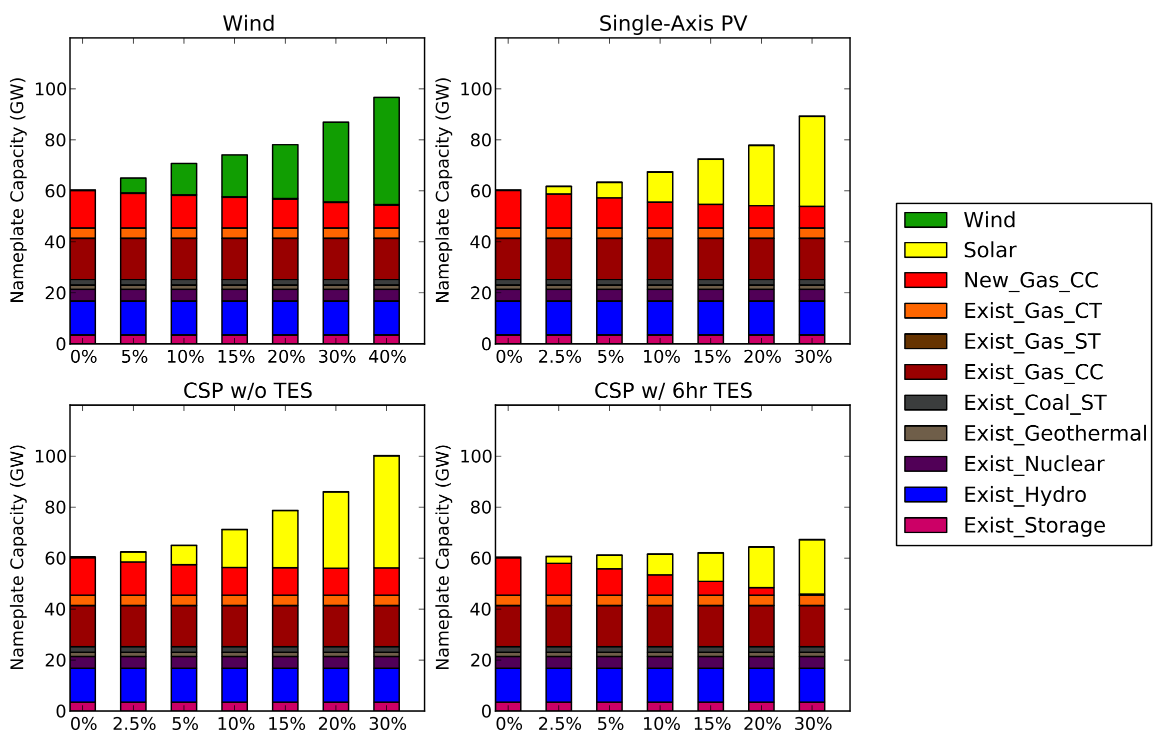


Figure 2: Total nameplate capacity of generation with increasing penetration of variable generation.

non-VG) nameplate capacity with increasing penetration for each VG technology shown in Figure 2 can be explained by the fact that the capacity credit of the VG resources is in most cases far below 100% of the nameplate capacity and is therefore also far below the capacity credit of new CCGT resources or of a flat block of power. Since the capacity credit of VG is less than the capacity credit of new CCGT resources that are used to meet system needs in the 0% VG case, the total nameplate capacity of all generation increases.

There are also important differences between the various VG technologies in terms of their capacity credit. At low penetration, the capacity credit of the solar technologies is highest. This high capacity credit is due to the coincidence of solar production and scarcity prices, which at low penetration occur during times with peak demand. The capacity credit of PV and CSP_0 calculated in this model is within a similar range estimated for low penetrations of solar using more detailed probabilistic methods (Shiu et al., 2006; Pelland and Abboud, 2008; Madaeni et al., 2012). The ability of TES to shift production from mid-day into the later afternoon hours results in a significantly higher capacity credit for CSP_6 relative to CSP_0 and PV. The coincidence of wind production and scarcity prices is lower, which leads to a lower capacity credit for wind.

At high penetration, the capacity credit of PV and CSP_0 drop by a considerable amount while the capacity credit of wind only decreases by a small amount from its already low level. In fact, the marginal capacity credit of wind at high penetration is slightly greater than the capacity credit of PV and CSP_0 at high penetration. The steep decline in the capacity credit of PV and CSP_0 indicates that the addition of more PV or CSP_0 when the penetration of those technologies is already high does not offset as much conventional capacity as they did at low penetration levels. Intuitively, this is because with high PV and CSP_0 penetration the net load peaks during early evening hours, and no increase in PV or CSP_0 capacity can help meet demand during that time. More specifically, as will be described in Section 4.2, the decreasing capacity credit of these solar technologies is a result of prices decreasing during times with higher solar production (i.e. scarcity prices stop occurring in the afternoon on summer days) and scarcity prices shifting to early evening hours in the summer when there is little or no solar production from PV and CSP_0 yet demand is still high. The decreased capacity credit for PV or CSP_0 with increasing penetration has been noted before (Kahn, 1979; Perez et al., 2008).

With thermal storage, however, the TES is dispatched such that a CSP_6 resource continues to produce power into the early evening and even later evening hours until the normal diurnal demand is considerably lower. The capacity credit of CSP_6 is therefore relatively high both at low penetration and high penetration.

4.1.2 Energy Production

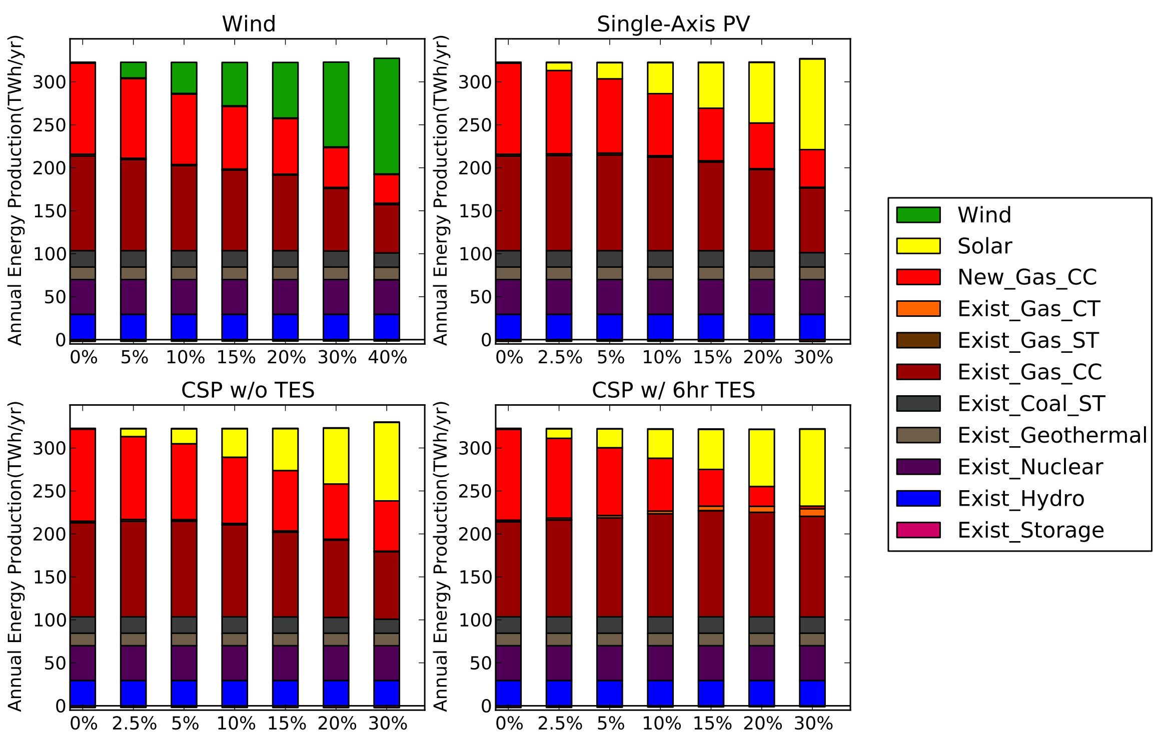
Irrespective of the ability of VG to reduce the amount of conventional capacity that is built in future years, it is clear that all VG resources reduce the amount of electricity that is generated by conventional generation. Similar to the impact of adding a flat block of power, generation from natural gas fired CCGTs is found to be particularly affected with increasing penetration of VG as shown in Figure 3. The slight increase in total energy production with increasing VG penetration in Figure 3, as opposed to constant energy production across all scenarios, is due to the energy that is available from VG but is curtailed. Curtailment is examined in more detail later in this section.

The amount of energy from incumbent CT resources remains a small fraction of total generation. Only in the high penetration cases with CSP_6 does the generation from CT resources increase a noticeable amount.

Further investigation shows that the increase in energy from CT resources in high CSP_6 penetration

Table 4: Effective incremental capacity credit of VG at low and high penetration levels.

Technology	Low Penetration of VG 0% → 5%			High Penetration of VG 15% → 20%		
	Incremental Reduction in Non-VG Capacity (GW)	Incremental Increase in VG Capacity (GW)	Effective Marginal Capacity Credit	Incremental Reduction in Non-VG Capacity (GW)	Incremental Increase in VG Capacity (GW)	Effective Marginal Capacity Credit
Flat Block	2.1	2.1	100%	1.6	1.6	100%
Wind	1.0	5.7	18%	0.7	4.7	15%
PV	2.8	5.8	48%	0.4	5.9	7%
CSP_0	2.7	7.3	37%	0.2	7.4	2%
CSP_6	4.3	5.1	84%	2.5	4.8	52%



Note: Energy for existing storage (Exist_Storage) is a negative value that represents the net energy consumed by pumped hydro storage.

Figure 3: Total energy generation from different resources with increasing penetration of variable generation in 2030.

scenarios is due to a lack of sufficient energy generation in winter months. One interesting trend noted earlier in Table 1 is that power prices are less likely to rise to high levels in the cases with increasing penetration of CSP_6. This lack of high price periods coupled with new generation investment in CCGT resources and an increase in CT production indicates that the system is increasingly "energy-constrained" rather than "capacity-constrained" in these scenarios. In these high CSP_6 cases, new CCGT resources are built, in part, to provide energy in winter months. In December, in particular, sufficient capacity is available to meet demand between the capacity of the thermal plants, hydropower generation, storage, and CSP_6 resources. However, in order to meet demand, during this month the capacity factor of CT resources rises to 98% when in a case with no VG the CTs would normally be off for the entire month. While the thermal generation is dispatched near to its maximum capacity for the month of December, the amount of energy that can be produced over the month by hydropower and the amount of energy that can be produced by CSP_6 resources is limited due to resource constraints (limited water supply for the hydro resources and extended cloudy periods for the CSP_6). The addition of new CCGT plants provides additional energy in December in addition to capacity in other high load months.

The incumbent PHS is represented as a net consumer of energy on the system in Figure 3 because storage consumes more electricity during the storage cycle than it can discharge during the generation cycle. The net energy consumption of storage is very small, usually less than 2 TWh/yr, and does not change noticeably between the high and low penetration cases for most VG technologies. With high penetrations of CSP_6 the net energy consumption of PHS decreases. The decrease indicates that incumbent PHS is used less frequently in the high CSP_6 cases than it is used in cases without VG. This is presumably because the system has access to considerable amounts of TES and arbitrage opportunities between low and high price periods are less prevalent.

At high penetration levels a small amount of incumbent coal generation is also displaced by VG. Since the variable cost of coal is much lower than the variable cost of CCGT resources, natural gas plants will generally be dispatched to their lower limits before coal plants are dispatched down. The slight reduction in energy generation from incumbent coal plants indicates that coal plants will be the marginal plant more often in cases with high VG than in cases without VG. In regions of the country with more incumbent coal than California the displacement of coal is expected to occur at a lower penetration of VG than observed in this case study.

Even before displacing energy from coal plants, however, cases with VG increasingly decrease the energy production from natural gas CCGTs. The ratio of the energy produced by incumbent natural gas CCGTs to the energy that could be produced if the CCGT were at full output all year, also known as the CCGT capacity factor, decreases with increasing penetration of VG, Table 5. Even increasing the penetration of a flat block of power, however, causes incumbent CCGTs to have a lower capacity factor. The increased energy available from the flat block of power effectively pushes the supply curve out, increasing the frequency by which incumbent CCGTs are marginal generation resources, at minimum generation, or offline.[5] Relative to the impact of a flat block, adding wind, PV, or CSP_0 further decreases the capacity factor of incumbent CCGTs with increasing penetration. The capacity factor of incumbent CCGTs increases with increasing CSP_6 relative to the same amount of energy with a flat block of power.

[5]This reduction in capacity factors for incumbent resources with increasing penetration of a flat block of power is similar to the observation by Milligan et al. (2011) that increasing penetrations of a flat block could lead to increased cycling of incumbent coal plants.

Table 5: Capacity factor of mid-size incumbent CCGT resources with increasing penetration of VG in 2030.

	Capacity Factor (%) Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	81%	n/a	80%	79%	77%	75%	69%	58%
Wind	81%	n/a	78%	72%	68%	63%	52%	40%
PV	81%	82%	82%	80%	76%	70%	59%	n/a
CSP0	80%	82%	82%	79%	74%	68%	61%	n/a
CSP6	81%	83%	85%	89%	91%	89%	85%	n/a

Though the capacity factor of incumbent CCGTs decreases substantially with increasing penetration of most VG technologies, the load factor of the CCGTs does not necessarily decrease at the same rate with increasing VG penetration. The load factor for a CCGT vintage is the energy-weighted average of the ratio of the actual generation from the CCGT vintage relative to the amount of the CCGT vintage that was on-line. The load factor in a particular hour where the new CCGT vintage was generating at 800 MW when 1000 MW of the new CCGT vintage was online would be 80%. Since CCGT plants are most efficient when operated at their full capacity, the most efficient dispatch, assuming there were no AS requirements, no forecast errors and no start-up costs, would always ensure that the amount of on-line generation exactly matched the amount of energy that would be needed from the generation vintage in each hour. The new CCGT vintage would therefore only have 800 MW online when it was generating at 800 MW, such that the load factor was 100% (i.e., at full-load).

Constantly matching the amount of power generated by the vintage to the amount of the vintage that is online would require frequent start-ups and shutdowns of the generation resources. The dispatch model used in this paper is formulated to account for AS requirements, DA forecast errors and start-up costs which means the load factor can and will be less than 100% (i.e., part-loaded) in any hour. The load factor of a vintage is less than 100% in some hours due to some combination of (1) contributions toward meeting the AS targets, (2) redispatch to manage forecast errors between the DA and RT and (3) avoiding start-up costs associated with bringing CCGT capacity on-line. The latter factor can also decrease the load factor of CCGTs in a case with an increasing penetration of a flat block of power. Hence, cases with high VG penetration and even the case with high penetrations of a flat block of power increasingly require natural gas CCGTs to be operated at part-load. Increased operation at part-load will decrease the overall efficiency of CCGT plants.

The decrease in efficiency at part-load means that the actual reduction in fuel consumption and emissions measured by the dispatch model is less than the reduction that would be expected if the efficiency of CCGTs remained at the full-load efficiency level even while part-loaded. The increase in part-loading of CCGT plants is quantified by examining the load factor of CCGT resources with increasing penetration in Table 6.

The results in Table 6 indicate that mid-size incumbent CCGT resources operate at part-load (a load factor less than 100%) more frequently with high penetration of a flat block, but even more so with high VG penetration, except with CSP_6 where the TES helps the mid-size incumbent CCGT be dispatched more efficiently. Even with high VG penetration, however, the load factor remains above 90%. A mitigating factor

Table 6: Energy-weighted average load factor of mid-size incumbent CCGT resources with increasing penetration of VG in 2030.

	Load Factor (%) Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	97%	n/a	96%	96%	96%	95%	94%	93%
Wind	97%	n/a	96%	95%	94%	93%	92%	91%
PV	97%	97%	98%	97%	94%	91%	91%	n/a
CSP_0	96%	97%	98%	97%	94%	93%	92%	n/a
CSP_6	97%	98%	98%	99%	99%	99%	98%	n/a

Table 7: Average heat rate of mid-size incumbent CCGT resources with increasing penetration of VG in 2030.

	Average Heat Rate (MMBTU/MWh) Penetration of VG							
VG Technology	0%	2.5%	5%	10%	15%	20%	30%	40%
Flat Block	7.2	n/a	7.2	7.2	7.2	7.2	7.3	7.3
Wind	7.2	n/a	7.2	7.2	7.3	7.3	7.3	7.4
PV	7.2	7.2	7.2	7.2	7.3	7.4	7.6	n/a
CSP_0	7.2	7.2	7.2	7.2	7.3	7.4	7.5	n/a
CSP_6	7.2	7.2	7.2	7.2	7.2	7.2	7.2	n/a

that helps keep the load factor from dropping too low with VG penetration, even though the capacity factor of the same vintage drops at a much faster rate, is the ability to shut-down CCGT resources during low load or high VG generation periods rather than always part-loading the resource. The tradeoff is the increase in start-up costs to bring the generation offline and then back online at a later point.

Increased part-load operation, more frequent start ups, and increased provision of reserves from on-line resources will reduce the overall average efficiency of thermal plants in converting fuel into electricity. The reduction in efficiency can be observed through an increase in the ratio of annual fuel consumption to annual energy production, or the average heat rate of a resource. The average heat rate of a particular vintage of thermal generation, incumbent mid sized CCGT resources, is shown to slightly increase with increasing penetration of a flat block and increase even more with increasing penetration of VG in Table 7, with CSP_6 again being an exception due to the thermal energy storage. For the other VG technologies, this reduction in efficiency of thermal generation also leads to a reduction in the avoided emissions from adding VG than otherwise would be the case were efficiency degradation not to occur.

4.1.3 Avoided Emissions

A byproduct of the investment and dispatch decisions is the pollution emissions from the thermal generation with increasing penetration of VG.[6] Since the addition of VG is found to primarily displace electricity

[6] We do not include any existing emissions related policies that would impact the cost and quantity of power plant emissions in California, such as a SO_2 cap-and-trade program. Actual emissions will be impacted by technology characteristics (which are modeled in this paper) as well as regulations (which are not considered here). Moreover, NO_x and SO_2 are regional pollutants

generated by incumbent and new natural gas fired CCGT plants in the cases evaluated here, the reduction in emissions relative to a case without VG are also primarily from avoiding emissions from CCGT resources. The avoided CO_2 emissions are proportional to the avoided fuel combustion in thermal resources. The avoided NO_x and SO_2 emissions, however, are not proportional to fuel consumption due to emissions during start-up and part-load that are greater than would be expected based on the fuel burned during those times. NO_x emissions during start-up and part-load operation are reported to be particularly high (Denny and O'Malley, 2006; Katzenstein and Apt, 2009; Suess et al., 2009).

The formulation of the dispatch model accounts for the increase in emissions during start-up and due to part loading of thermal plants, though the same caveats regarding the simplification of the commitment and dispatch based on vintages applies equally to estimating the avoided emissions. The total emissions of CO_2, NO_x, and SO_2 all decrease with increasing VG penetration relative to the case with 0% VG penetration. The CO_2 emissions with increasing VG penetration are shown in Figure 4. The decrease in emissions with increasing penetration of all VG indicates that the start-up and part-load emission impacts are secondary to the overall reduction in electricity production from thermal generation, the main driver of the decrease in emissions. CO_2 emissions are found to decline with increasing VG penetration to a greater degree in percentage terms than NO_x and SO_2. This difference is because NO_x and SO_2 are found to be dominated by the relatively small amount of incumbent coal resources that are not, until very high penetration, displaced by VG.

Another way to examine the avoided emissions from adding VG is to show the ratio of the incremental reduction in emissions between two cases and the incremental increase in VG generation between those two cases. This incremental avoided emissions rate is shown for CO_2 in Table 8. The avoided emissions rate is similar to the rate of emissions of a fully-loaded CCGT plant at high and low penetration levels (385 kg CO_2/MWh for a mid-sized incumbent CCGT), except when VG starts displacing generation from coal resources. The reduction in efficiency due to part-loading and start-up of thermal generation ends up leading to a small reduction in the overall incremental avoided CO_2 emissions rate at high penetration relative to the incremental avoided CO_2 emissions rate at low penetration, as shown in Table 8, particularly for PV and CSP_0. The somewhat greater degradation in CO_2 emissions benefits for PV and CSP_0 are presumably caused by the relatively higher part loading and start up required to manage these resources relative to wind and CSP_6.

These avoided emissions results are dependent on the particular mix of generation and assumptions regarding retirement. In particular, regions with more incumbent coal than California would have emissions from coal plants displaced by VG at lower penetration levels than found in this case study. Nonetheless, the main conclusion from these results is that adding VG avoids emissions, even when part-load and start up emissions are accounted for. The magnitude of avoided emissions depends on the mix of generation (including retirements), the type of generation that will be built in future years, and the generation profile of VG.

where the damage of the pollutant depends on factors including where pollution is emitted from, when the pollutant is emitted, and prevailing weather conditions, not just the quantity of pollutant emitted. These factors are not considered in this analysis.

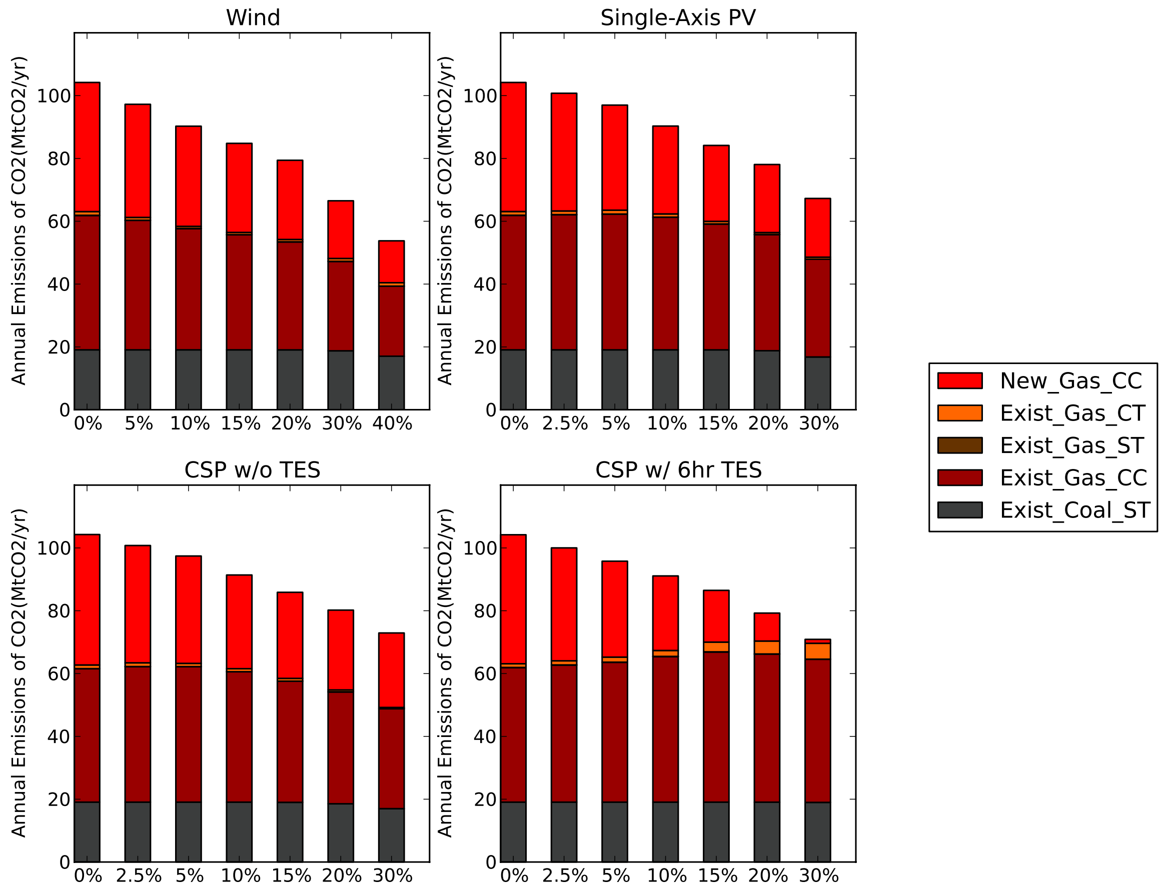


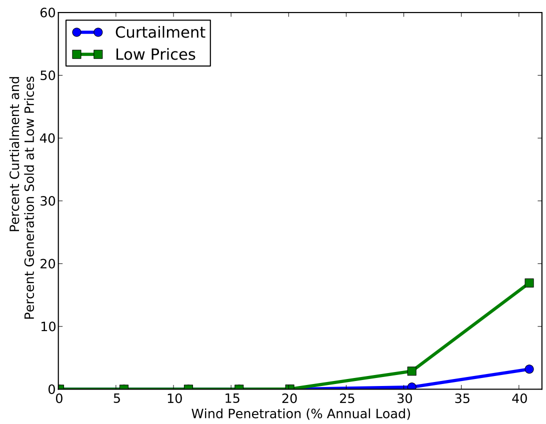
Figure 4: Total CO_2 emissions from different resources with increasing penetration of variable generation in 2030.

Table 8: Incremental avoided CO_2 emissions rate of VG at low and high penetration level in 2030.

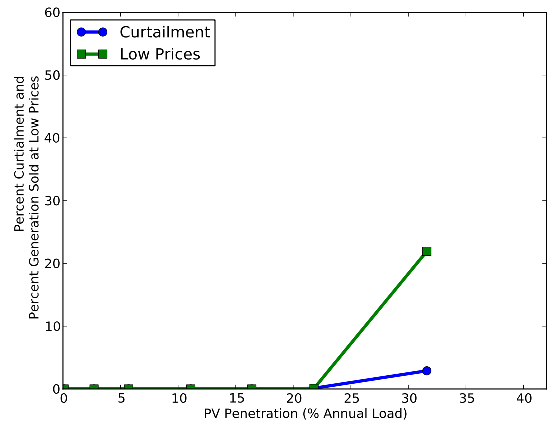
Technology	Low Penetration of VG 0% → 5%			High Penetration of VG 15% → 20%		
	Incremental Reduction in CO_2 Emissions (10^9 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (kg/MWh)	Incremental Reduction in CO_2 Emissions (10^9 kg/yr)	Incremental Increase in VG Generation (TWh/yr)	Marginal Rate of Avoided Emissions (kg/MWh)
Flat Block	7.0	18	390	5.5	14	390
Wind	7.0	18	390	5.4	14	380
PV	7.2	18	400	6.1	17	350
CSP_0	6.8	17	410	5.7	16	350
CSP_6	8.4	21	400	7.2	20	370

4.1.4 Curtailment

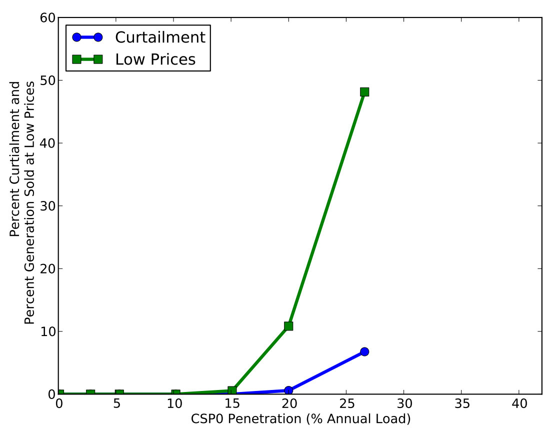
At higher penetration levels, VG will sometimes produce power when the system has limited flexibility to manage the additional VG (i.e., the system has limited ability to reduce the output of other generation). During these hours the wholesale price for electricity will decrease to very low levels (approaching $0/MWh) which may make VG indifferent to curtailing (and earning no revenue) or generating (and earning almost no revenue). When even more VG is available during these constrained times curtailment of VG will be required. In contrast to VG, curtailment did not occur for increasing penetrations of the flat block of power.



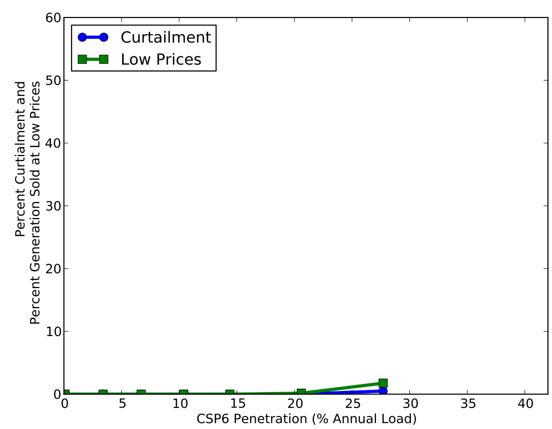
(a) Wind



(b) PV



(c) CSP_0



(d) CSP_6

Figure 5: Curtailment of variable generation and percentage of variable generation that is sold during periods where wholesale power prices are very low (<$1/MWh) in 2030.

The challenges of accommodating higher penetrations of VG can therefore be illustrated in two ways: (1) by examining the amount of VG that is sold at low prices and (2) by examining the amount of VG that has to be curtailed, Figure 5. The amount of energy that is sold at low prices is based on summing the amount of

VG scheduled in the DA that occurs when the DA price is below \$1/MWh with the amount of RT deviations from the DA schedule that is sold when the RT price is below \$1/MWh. The amount of curtailment is based on the difference between the amount of energy that is used in the market relative to what could have been used if there were no curtailment. Note that CSP resources have solar fields that are sized larger than the power block (i.e., a solar field multiplier that is greater than 1) in this model. The curtailment that is due to this oversizing was excluded from the curtailment reported here by only focusing on curtailment of CSP that occurs during periods with very low prices (<\$1/MWh). This curtailment reflects power system flexibility constraints rather than factors related to the design of CSP plant for cost minimization.

The amount of energy that is sold at low prices increases at a much faster rate with increasing penetration than the amount of VG curtailment. The reason is that when curtailment occurs, only the fraction of the VG generation that exceeds what the system can economically accommodate is curtailed whereas all of the DA scheduled energy is sold at low prices when the DA prices are low. For example, if in a particular hour the DA forecast of VG was 1000 MW but the system could only economically accommodate 950 MW of VG in the DA scheduling process, then 50 MW of VG generation would be curtailed but the remaining 950 MW of generation would be sold at a price of \$0/MWh.

Changes in curtailment and the amount of energy sold at low prices with increasing penetration differ substantially across VG technologies. For wind and CSP_6, the amount of energy that is curtailed in the 30% penetration case is less than 1% of the annual available energy. At 40% penetration of wind, curtailment is around 2.5%. At 30% and 40% penetration of wind the amount of energy that is sold at low prices is around 3% and 18% of the annual available wind, respectively. For CSP_6, thermal energy storage helps reduce the amount of energy sold at low prices, less than 2% at 30% penetration. PV and CSP_0 experience substantially greater curtailment and amount of energy sold during low price periods than do CSP_6 and wind, especially at penetrations above 15–20%. The curtailment and amount of energy sold at low prices for CSP_0 at 30% penetration, for example, is 7% and 48%, respectively, more than double the curtailment and amount of energy sold at low prices for wind at 40% penetration. The curtailment and amount of energy sold at low prices for PV follows a similar path as CSP_0. Though not shown here, incremental curtailment rates (incremental curtailment per unit of incremental VG energy) when increasing penetration from 20% penetration to 30% penetration are much higher than average curtailment rates (total curtailment per unit of total VG energy). In the case of CSP_0 the incremental curtailment rate between 20% and 30% penetration is approximately 22%.

The curtailment and amount of energy sold at low prices has an impact on the marginal economic value of VG at high penetration, impacting PV and CSP_0 to a greater extent than wind and CSP_6 (see Sections 4.2 and 4.3). Curtailment was highlighted by Denholm and Margolis (2007) as a potential limit to PV penetration. This paper adds further insight by highlighting the portion of VG that is sold at low prices. The curtailment of VG is relatively low compared to other studies and the current curtailment that is observed for wind at relatively low penetration rates for three reasons. First, California is a relatively flexible system with significant hydro resources and substantial gas-fired generation. Analysis of curtailment with increasing PV penetration by Denholm and Margolis (2007) highlighted the important role of the overall system flexibility in mitigating PV curtailment at increasing penetration levels. Second, in long-run equilibrium in 2030 no plants with high fixed costs and low variable costs, such as nuclear generation, are found to be built. If these plants were built the total amount of inflexible baseload generation would increase and curtailment of variable generation would similarly increase. Third, this analysis does not consider curtailment due to insufficient transmission capacity. Curtailment due to insufficient transmission capacity between generation and loads is one of the largest contributors to wind curtailment that is currently occurring in the U.S.

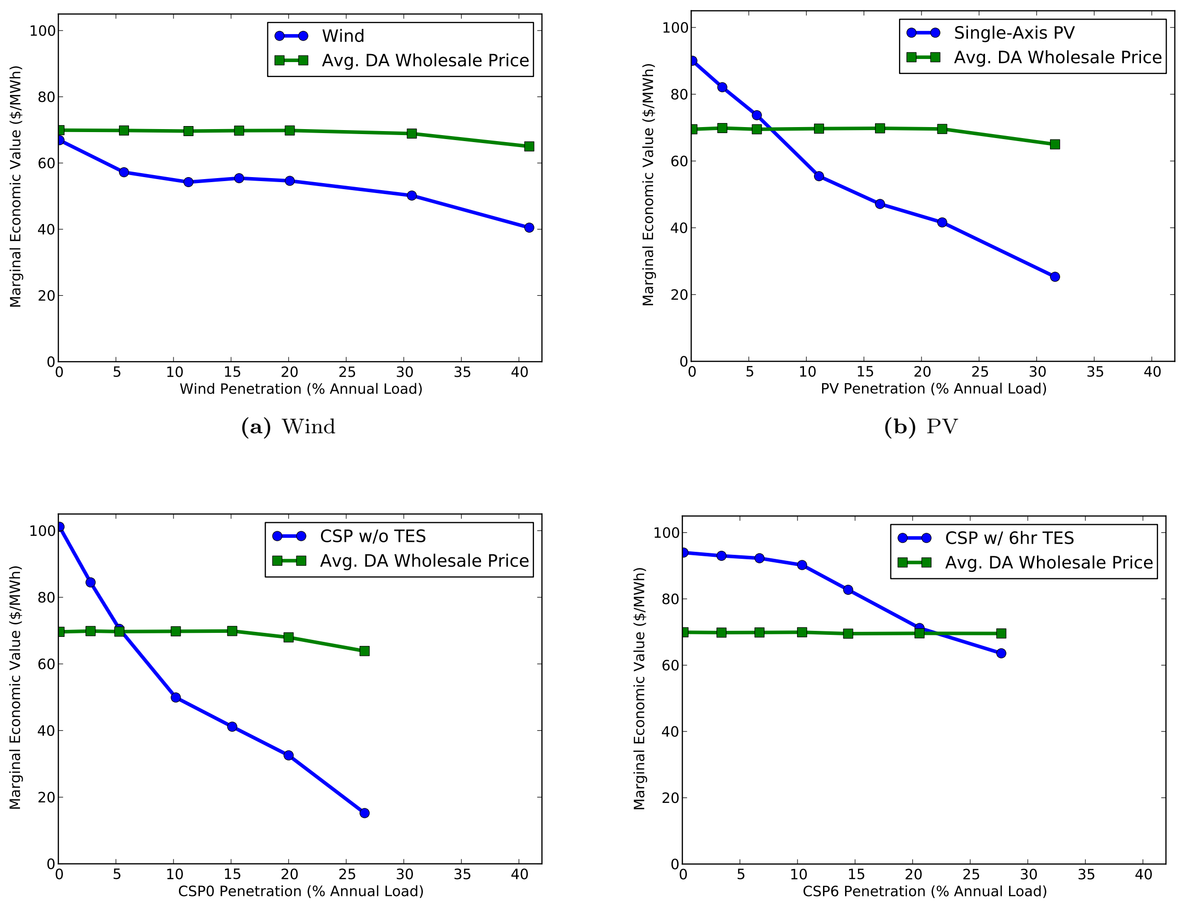
4.2 Marginal Economic Value

The preceding dispatch and investment results point to a number of important differences between VG technologies and highlight the impact of increasing VG penetration. At low penetration, solar has a much greater capacity credit than wind. Both wind and solar primarily displace electricity, fuel, and emissions from natural gas CCGT resources at low penetration, under the assumptions used in this paper. At high penetration, the marginal capacity credit of wind declines but neither the capacity credit nor the resources that are being displaced by wind generation change dramatically. For solar at high penetration, however, the marginal capacity credit of PV and CSP_0 decrease substantially from the capacity credit at low penetration and these resources begin to displace energy from coal plants. At high penetration more curtailment and energy sales at low energy prices is expected for PV and CSP_0 than for wind. Due to thermal energy storage, CSP_6 maintains a higher marginal capacity credit even at high penetration and avoids substantial curtailment and energy sales during times with low energy prices.

This section explores the impact of these trends on the relative differences in the marginal economic value of wind and solar and how the marginal economic value changes with increased penetration. The marginal economic value is calculated as the short-run profit earned by VG from selling power into a DA and RT power market that is in long-run equilibrium for the given VG penetration. The total revenue is calculated as the sum of the revenue earned for selling forecasted generation into the DA market at the DA price and the revenue earned for selling any deviations from the DA forecast in the RT market at the RT price. Wind, PV, and CSP_0 generation can sell the AS of regulation-down, but they are also charged for an assumed increase in the hourly AS requirements equivalent to 5% of the hourly DA forecast of the VG due to increased short-term variability and uncertainty. The increase in AS requirements due to VG is informed by the rules-of-thumb developed in the WWSIS and previous analysis of high-time resolution, geographically diverse solar irradiance data (Mills and Wiser, 2010). CSP_6 on the other hand is assumed to be able to sell AS both in the up and down direction due to the thermal storage. No additional AS are assumed due to the addition of CSP_6.

The calculated marginal economic value of wind, PV, CSP_0, and CSP_6 with increasing penetration of each VG technology is shown in Figure 6. For comparison purposes, the time-weighted average wholesale DA price in each case is also shown. The average wholesale price is relatively constant with increasing penetration of VG until high VG penetration levels. This relatively constant wholesale price with increasing VG is largely a result of the assumption that the rest of the non-VG system remains in long-run equilibrium. In particular, this assumption of long-run equilibrium requires prices to rise high enough and frequently enough to cover the fixed cost of any new non-VG investment. Since all cases require some new non-VG capacity to be built the prices must be sufficiently high to cover the fixed cost of that new non-VG generation. Only at very high penetration levels (>20% energy penetration) does the time-weighted average wholesale price begin to decrease, though the non-VG system remains in long-run equilibrium.

The marginal economic value of wind is found to be similar to (but slightly lower than) the average wholesale price at low penetration levels. As the penetration of wind increases to 20%, the marginal value of



(a) Wind

(b) PV

(c) CSP_0

(d) CSP_6

Figure 6: Marginal economic value of variable generation and an annual flat-block of power with increasing penetration of variable generation in 2030.

adding additional wind decreases by approximately \$12/MWh relative to the case without wind even though the average wholesale price does not change. At very high penetrations of 30% and 40% the marginal value of wind decreases further. At 40% wind penetration the time-weighted average wholesale price also begins to decrease.

The marginal economic value of wind can be used to indicate the "grid-parity" cost where the economic value of the wind plant would equal the fixed cost of the wind plant. If the annualized fixed cost of wind is above the marginal economic value of wind, then no additional wind would be built based only on this comparison (of course more might be built based on other non-market factors including an RPS requirement or because of other factors not modeled here). If, on the other hand, the annualized fixed cost of wind were less than the marginal economic value of wind then it would be economically attractive to add more wind assuming again that no other factors are at play. The declining marginal economic value of wind with increasing penetration indicates that the cost of wind needs to be continuously driven lower to justify adding more wind strictly on economic grounds, particularly for adding additional wind beyond 20% penetration. Related, the value to a utility of adding more wind decreases when there is already significant wind penetration.

As shown in Figure 6, the marginal economic value of solar exceeds the time-weighted average wholesale DA price of power as well as the marginal value of wind at low penetration levels. The high value of solar, \$20–30/MWh higher than the average wholesale power price and the marginal economic value of wind, is due largely to the high degree of coincidence of solar generation and times of peak load and scarcity prices when using a demand profile based on California loads. This high degree of coincidence is also what led to the high capacity credit estimated earlier in Section 4.1. The high marginal economic value of solar resources at low penetration has been highlighted in several recent studies (e.g., Borenstein, 2008; Lamont, 2008; Sioshansi and Denholm, 2010). Of course, when comparing wind and solar resources in procurement decisions the higher marginal economic value of solar at low penetration must also be weighed against the relative levelized cost of wind and solar supply.

One particularly interesting result at low penetration levels is that the marginal economic value of PV, CSP_0, and CSP_6 are all relatively similar on a \$/MWh basis. This shows that there is not a strong economic signal at low penetration levels that would indicate that CSP with TES would be more valuable than a plant without TES on a per unit of energy basis. It might be possible to justify the addition of TES to a CSP plant based on the fact that TES can increase the capacity factor of a CSP power block. Depending on the cost of TES and the cost of increasing the solar field size, adding TES may actually decrease the levelized cost of a CSP plant (Herrmann et al., 2004; Turchi et al., 2010). At low penetration, the cost reduction benefits would need to be the primary motivation for adding TES since there is not a clear increase in the value of CSP with TES relative to the value of CSP without TES. This finding supports the relatively sparse market interest in CSP with TES in markets that currently have low solar penetration.

As the penetration of solar is increased to 10% the marginal value of adding additional PV and CSP_0 drops significantly relative to the marginal economic value of adding additional CSP_6. At 10% penetration, the marginal economic value of adding additional CSP_6 is about \$4/MWh less than the value at 0% penetration. For solar without TES, in contrast, the marginal economic value of adding more solar at 10% penetration is \$35/MWh and \$50/MWh less than the value of adding solar at 0% penetration for PV and CSP_0, respectively.

Also at about 10% penetration, the marginal economic value of PV and CSP_0 reach and then drop below the economic value of wind. The marginal economic value of CSP_6, on the other hand, remains above that of wind at all penetration levels considered here.

This relative difference in value at high penetration indicates that solar resources with TES can be substantially more valuable than resources without TES. Of course, the decision to procure CSP with TES relative to other solar technologies would also need to consider the relative cost of these options. If the recent rapid decrease in the price of PV is sustained and the cost of CSP with TES does not follow the same trajectory, then PV could still be a more attractive option for increasing solar penetration even with 10% PV penetration and despite the lower marginal economic value.

At higher penetrations of VG, the marginal economic value of adding additional PV or CSP_0 is below the marginal economic value of wind. While the economic value of wind starts lower than the value of the three solar technologies at low penetration, its value does not drop as fast as the marginal economic value of PV and CSP_0. In this particular case, the wind resources that are procured at high penetration levels increasingly come from diverse wind regions that are out-of-state. The diversity in the wind generation patterns and forecast errors are part of the reason for the slower decline in the value of wind with high penetration. Solar generation profiles, on the other hand, are largely dictated by the position of the sun. Geographic diversity can help mitigate short term variability issues due to clouds, but it does not impact the overall daily solar generation profile.

4.3 Decomposition of Marginal Economic Value

The marginal economic value of VG and the flat block of power can be decomposed into several components in order to better pinpoint the causes of the high economic value of solar at low penetration, the relatively slow decline in the value of wind with increasing penetration, the drivers for the steeper decrease in the value of PV and CSP_0 with higher penetration, and the reasons for the substantially higher value of CSP_6 relative to the other VG at high penetrations. Without this decomposition step it is not clear if these trends are due to changes in capacity credit, changes in thermal generation that is being displaced, imperfect forecastability, or AS impacts.

In this section the marginal economic value of VG is decomposed into capacity value, energy value, DA forecast error, and AS impacts. All of these components are presented in terms of \$/MWh-of-VG such that the values can be easily compared.

- Capacity Value (\$/MWh): The portion of short-run profit earned during hours with scarcity prices (defined to be greater than \$500/MWh).
- Energy Value (\$/MWh): The portion of short-run profit earned in hours without scarcity prices, assuming the DA forecast exactly matches the RT generation.
- Day-ahead Forecast Error (\$/MWh): The net earnings from RT deviations from the DA schedule.
- Ancillary Services (\$/MWh): The net earnings from selling AS in the market from PV and paying for increased AS due to increased short-term variability and uncertainty from PV.

Decomposing the marginal economic value in this way helps to understand the causes for changes in the value of VG and, perhaps more importantly, can help identify promising strategies for mitigating decreases in the marginal economic value of VG with increasing penetration. The results of the decomposition are shown in Table 9. For comparison, the marginal economic value of a flat block of power that is assumed to have no variable fuel or O&M cost is equivalent to the time-averaged wholesale DA price of power, which at low penetration levels is about $70/MWh. The capacity value of a flat block between 0% to 30% penetration is found to be about $20/MWh (or about $170–180/kW-yr) and the energy value is about $50/MWh.[7] Only at 40% penetration does the energy value and capacity value of the flat block of power begin to decrease.

Up to 30% penetration the decomposition for wind shows that the marginal economic value of wind is less than the marginal value of a flat block due primarily to the lower capacity value of wind. As the penetration of wind increases from 0% to 20% penetration, for example, the marginal capacity value of wind decreases by $8/MWh. The energy value of wind at 0% penetration is found to be similar to the energy value of a flat block of power. Moreover, the energy value only drops by $2.5/MWh when the penetration of wind increases from 0% to 20%. At still higher penetration levels the capacity value of wind is relatively stable while the energy value begins to fall more noticeably between 30% and 40% penetration.

DA forecast error costs are found to be meaningful, though these costs do not impact the marginal economic value of wind as much as the declining capacity value and energy value in this particular region. In addition, while the absolute $/year cost of forecast errors steadily increases with increasing wind penetration, the changes in the DA forecast error cost per unit of wind energy are somewhat ambiguous with increasing penetration. At first, as wind penetration grows from 0% to 10% the DA forecast error cost increases up to $4/MWh. Between 10% to 20%, however, the DA forecast error cost declines to $2/MWh and then begins to increase again at 30% penetration up to a cost of $6/MWh at 40% penetration. There are three primary factors of the DA forecast error cost that can contribute to the variation: (1) the difficulty associated with managing DA forecast errors (measured by the standard deviation of the difference between the DA and RT price), (2) the relative magnitude of the DA forecast errors (measured by the standard deviation of the difference between the RT generation and the DA forecast for wind normalized by the annual wind generation), and (3) the correlation between DA and RT differences in prices and wind generation.

Each of these factors are examined in turn to better understand the causes of the variation in the DA forecast error cost. With increasing penetration of wind the relative magnitude of wind forecast errors decreases between 0% and 30% penetration due to increasing geographic diversity in wind sites and only slightly increases between 30% and 40% wind penetration. The correlation between DA and RT wind deviations and price deviations steadily increases with increasing penetration. The remaining factor, the difficulty with managing DA forecast errors, is therefore the main contributor to the variability of the DA forecast error cost with increasing penetration. Between 0% and 10% penetration the difficulty with managing DA wind forecast errors steadily increases. Between 10% and 20% penetration, however, the spread of differences between DA and RT prices decreases. This indicates that the cost of "purchasing" power in RT to make up for a generation shortfall between DA and RT or the discount for "selling" power in RT that exceeds the DA scheduled generation are lower between 10% to 20% penetration than between 0% to 10% penetration. Beyond 20% penetration the cost of purchasing power in RT or the discount for selling power in RT increases to levels beyond those at 10% penetration resulting in an overall increase in the DA forecast error cost at 40% penetration.

[7]The capacity value of a flat block is similar to the cost of capacity in this market, which corresponds to the fixed cost of new CCGT resources ($200/kW-yr = $23/MW-h). The energy value of a flat block is similar to the fuel and variable O&M cost of a fully loaded CCGT ($46–52/MWh in the model used here, depending on the vintage).

Table 9: Decomposition of the marginal economic value of variable generation in 2030 with increasing penetration.

Component	Penetration of a Flat Block						
($/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(170) 20	(180) 20	(170) 20	(180) 20	(180) 20	(180) 20	(140) 16
Energy Value	50	50	50	50	50	50	49
DA Forecast Error	0	0	0	0	0	0	0
Ancillary Services	0	0	0	0	0	0	0
Marginal Economic Value	70	70	70	70	70	70	65

Component	Penetration of Wind						
($/MWh)	0%	5%	10%	15%	20%	30%	40%
Capacity Value[a]	(69) 17	(37) 12	(30) 10	(30) 10	(28) 9	(25) 8	(25) 8
Energy Value	50	49	48	48	48	46	39
DA Forecast Error	-0.2	-3	-4	-2	-2	-3	-6
Ancillary Services	-0.4	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Marginal Economic Value	67	57	54	55	54	50	40

Component	Penetration of PV						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(120) 37	(110) 34	(82) 27	(39) 13	(24) 8	(11) 4	(4) 1
Energy Value	54	53	52	49	45	41	27
DA Forecast Error	-0.2	-5	-4	-6	-5	-4	-3
Ancillary Services	-0.9	-0.8	-0.7	-0.4	-0.2	-0.1	-0.0
Marginal Economic Value	89	81	73	55	47	41	25

Component	Penetration of CSP_0						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(110) 47	(84) 36	(54) 24	(22) 10	(11) 5	(6) 3	(5) 2
Energy Value	56	54	52	46	41	33	16
DA Forecast Error	-2	-5	-5	-6	-5	-4	-4
Ancillary Services	-1.1	-0.8	-0.5	-0.2	-0.1	-0.1	-0.1
Marginal Economic Value	100	84	70	50	41	32	14

Component	Penetration of CSP_6						
($/MWh)	0%	2.5%	5%	10%	15%	20%	30%
Capacity Value[a]	(150) 37	(160) 37	(150) 37	(150) 35	(100) 24	(85) 20	(61) 15
Energy Value	55	55	55	55	58	53	52
DA Forecast Error	-0.1	-1	-1	-1	-1	-2	-3
Ancillary Services	1.4	1.4	1.3	1.2	1.0	0.7	0.1
Marginal Economic Value	94	93	92	90	83	71	64

a - Capacity value in parentheses is reported in $/kW-yr terms and reported to two significant digits.

The ancillary service costs for wind are found to be low, less than \$1/MWh, and do not increase with increasing penetration. The large amount of hydropower in California helps to maintain low AS costs even with increasing AS targets. In all cases the time-weighted average price for regulation up remains in the range of \$8–10/MW-h. Hydropower does not entirely drive the AS costs, however, since similarly low AS costs and AS prices were observed during prior analysis by the authors of a region with significantly less hydropower (namely the Rocky Mountain Power Area) using the same model and similar assumptions. In addition, this price range for regulation up reserves is similar to the prices for regulation in recent years for several centralized markets in the U.S. (CAISO, MISO, and ISO-NE) but lower than regulation prices in other markets. Regulation prices in ERCOT, NYISO, and the CAISO prior to the recent market technology upgrade and redesign have been in the range of \$20–60/MW-h (Milligan and Kirby, 2010). Increases in the prices for ancillary services would potentially lead to higher costs for ancillary services for wind.

Interestingly, rather than AS costs increasing with increasing wind penetration, the AS costs actually slightly decrease with increasing penetration per unit of wind energy. The modeling assumptions in this analysis lead to AS targets increasing in proportion to the increase in energy generated by wind. As a result, if the AS prices (and their correlation with wind generation) did not change with increasing wind penetration then the cost of AS for wind would remain relatively constant with increasing wind production. In fact, the slight decrease in the cost of AS for wind with increasing penetrations shown in Table 9 and the relatively stable time-averaged AS prices indicates two potential changes that may occur as the penetration of wind increases. First, the AS prices could become lower specifically during times when wind power is generating and higher at other times as the penetration of wind increases from 0%. Second, wind could be selling more AS in the form of regulation down with increasing penetration. Examination of regulation down from wind shows that it does increase with increasing wind penetration, but the impact is negligible (less than \$0.003/MWh at 40% penetration). Thus the price of AS must decrease during hours with high wind penetration. Previous analysis of modeled regulation prices with increasing wind production in ERCOT noticed a similar trend. In a previous study by GE, regulation prices were found to decrease with increasing wind penetration even though the total regulation requirement increased (GE Energy, 2008).[8]

Though the findings are specific to the cases analyzed, overall, the decomposition of the value of wind shows that:

- The primary value of wind is the energy value. The energy value of wind at low penetration is similar to the variable cost of energy from a fully loaded CCGT. At high penetration, the energy value starts to decline as wind displaces energy from incumbent coal plants.
- The capacity value of wind is slightly less than the capacity value of a flat block of power at zero penetration. The capacity value of wind drops as penetration increases, but is relatively stable at a low value at medium to high penetration.
- The cost of day-ahead forecast errors is impacted by the degree of the wind site diversity, but remains

[8]This is explained by GE as follows: "In general, with increasing wind generation capacity, the unit price per MWh of spinning reserve decreases due to several factors. First, the balance of generation is provided by units with lower variable costs as wind generation capacity is increased. Second, because of the daily variability of wind generation, thermal units with long start-up times and minimum-run times tend to be scheduled for hours where their dispatch levels are reduced by wind output. This provides regulating range with virtually no opportunity cost for these high-wind hours. Third, the accuracy of wind forecasting used in the day-ahead unit scheduling plays a role. If wind generation forecasts are not considered at all, or are heavily discounted, the balance of generation will tend to be over-committed"(GE Energy, 2008).

below \$5/MWh except at very high penetration.

- Ancillary service costs are modest, less than \$1/MWh, and do not significantly increase at high penetration levels at least for the cases analyzed here.

These conclusions are broadly consistent with findings of the many detailed operational and valuation studies that have explored the impacts of higher levels of wind penetration. In particular, the ancillary service cost and day-ahead forecast error cost for wind are within the range, though on the lower end, of "integration costs" found in various operational integration studies of wind (DeCesaro et al., 2009). It should be recognized that there is some controversy regarding how these costs should be calculated and interpreted (Milligan et al., 2011).

The decomposition of the value of the three solar technologies shows that at low penetration, the primary reason that the value is greater than that of a flat block and of wind is due to the substantially greater capacity value. At 0% penetration, the capacity value of solar is \$17–27/MWh greater than the capacity value of a flat block (and more so when compared to wind).

Based on the earlier finding that the effective capacity credit of CSP_6 at low penetration was greater than the capacity credit of the other solar technologies, it is somewhat counter-intuitive that the capacity value of CSP_6 is not greater in dollars per unit of energy (\$/MWh) terms, though it is greater in dollars per unit of nameplate capacity (\$/kW-yr) terms. The reason is that the CSP_6 technology produces more energy per unit of nameplate capacity than the other solar technologies. As an illustration, consider two different 100 MW power plants that both earn the same \$8 million/yr revenue during hours with scarcity prices (or \$80/kW-yr), but one plant generates 200 GWh/yr and the other generates 400 GWh/yr. The plant that produces more energy over the year will have a lower capacity value of \$20/MWh while the plant that produces less energy over the year will have a higher capacity value of \$40/MWh. Along the same lines, consider the same two 100 MW plants but the plant that generates 400 GWh/yr earns the full \$8 million/yr revenue during hours with scarcity prices whereas the generation profile of the plant that generates 200 GWh/yr is such that it earns only \$4 million/yr during hours with scarcity prices (or \$40/kW-yr). The capacity value of both plants would be equal to \$20/MWh, notwithstanding the high capacity credit and the high capacity value in \$/kW-yr terms associated with the former.

Similarly, even though the CSP_6 technology is more likely to be producing power during scarcity hours and has a higher capacity value in \$/kW-yr terms it produces more energy per unit of capacity and therefore has a similar capacity value, in \$/MWh terms, to the other solar technologies. This also explains how the capacity value of CSP_0 can be greater than the capacity value of PV at zero penetration level in \$/MWh terms even though the capacity value in \$/kW-yr terms of CSP_0 is slightly lower than the capacity value of PV in \$/kW-yr terms. The difference between the capacity value of PV and CSP_0 in \$/MWh terms is due to the lower amount of energy per unit of nameplate capacity for CSP_0 relative to PV.

The energy value of solar at 0% penetration is found to be \$4–6/MWh greater than the energy value of a flat block because it displaces relatively less efficient, and therefore higher cost, gas plants during periods of high demand in summer. At 0% penetration the energy value of solar is similarly \$4–6/MWh greater than the energy value of wind.

The AS and DA forecast error cost for PV and CSP_0 are small in magnitude relative to the energy value and capacity value, and are also similar in magnitude to the AS and DA forecast error cost for wind.

Variations in AS and DA forecast error costs for PV and CSP_0 with increasing penetration are driven by similar factors as for wind, discussed earlier. Similar to what was found for wind, the DA forecast error cost increases in absolute $/year terms with increasing penetration, but the marginal DA forecast error cost per unit of solar energy does not monotonically increase with increasing penetration. Detailed analysis of the factors driving the DA forecast error cost similarly shows that the relative magnitude of forecast errors decreases with increasing penetration and that variations in the DA forecast error cost are primarily related to variations in the difficulty of managing DA forecast errors at different penetration levels.

One important difference with wind, however, is that further examination of the AS costs for PV and CSP_0 at high penetration levels shows that the sales of regulation down begin to become relatively more important in keeping the cost of ancillary services at the very low level at high penetration. At 0% penetration, for example, the cost of purchasing AS for CSP_0 is about $1.1/MWh and the revenues from selling regulation down from CSP_0 is zero, leading to a net cost of AS for CSP_0 at 0% penetration of about $1.1/MWh, as reported in Table 9. At 30% penetration, on the other hand, the cost of purchasing AS for CSP_0 is about $1.5/MWh and the revenues from selling regulation down from CSP_0 increases to about $1.4/MWh, leading to the reported net cost of AS of only $0.1/MWh. Revenues from the sale of regulation down only begins to exceed $0.05/MWh for CSP_0 penetration levels above 10%, indicating that provision of regulation down by CSP_0 plants is only found to be useful at higher penetration levels. Similar behavior is observed for the sale of regulation down by PV at high penetration levels.

The net AS portion is positive for CSP_6 indicating that CSP_6 resources are earning revenue from selling AS whereas the other VG technologies are net buyers of AS at all penetration levels. Regardless, because AS prices are found to be low (in the range of $8–10/MW-h for regulation up), the AS revenue earned by CSP_6 is found to be relatively low, under $2/MWh. As mentioned earlier in this section, if the AS prices were to be higher (as they are in some organized markets within the U.S.) the AS revenue for CSP_6 could potentially be higher. Though AS costs are relatively small, the provision of regulation down by PV and CSP_0 at high penetration levels and provision of AS by CSP_6 appears to be an area where further research and demonstration of technical capabilities might be of interest. Similar research is being conducted for wind (e.g., Kirby et al., 2010). Additional research specifically on the impact of ancillary service revenues for CSP with TES based on historical energy and AS prices is available from Sioshansi and Denholm (2010).

In all penetration levels the DA forecast error costs are found to be substantially larger than AS costs. Although DA forecast errors caused a decrease in the value of CSP_0 of up to $6/MWh, the same type of DA forecast errors were managed by the CSP_6 resource at a cost of at most $2/MWh. This may represent an upper bound to the value of TES in managing DA forecast errors, however, since perfect foresight is assumed in RT for the management of DA forecast errors.

The most dramatic change in the marginal value of VG resources is the decrease in capacity value of PV and CSP_0 with increasing penetration levels. By the time the penetration reaches 10% on an energy basis, the marginal capacity value decreases by $24/MWh and $37/MWh from the marginal capacity value at 0% penetration for PV and CSP_0, respectively. While at low penetration the marginal capacity value of PV and CSP_0 are considerably greater than the capacity value of wind and of a flat block of power, at 10% penetration the marginal capacity value from adding additional PV or CSP_0 is comparable to the marginal capacity value from adding additional wind. Beyond 10% penetration the capacity value of PV and CSP_0 continues to drop steeply relative to that for wind.

The change in capacity value with increasing penetration of PV and CSP_0 is explained in Figure 7. The figure shows the historical hourly load shape scaled up to 2030 and the net load (historical load less hourly solar generation) on three days of the year where high load leads to scarcity pricing. The net load is shown for increasing penetrations of PV. The log of the hourly wholesale price is also shown in the figure to illustrate the coincidence of times of high system need with times of solar generation. PV generates significant amounts of power during the scarcity period at low penetration levels, but as the penetration of PV increases, times with high net load and high prices shift towards the early evening, when PV production has dropped off. As similarly found in Section 4.1, PV generation clearly reduces the need for new capacity at low penetration, but with increasing penetration PV is less effective at reducing that need.

A similar net-load curve and pricing is shown with increasing levels of CSP_6 on the same three days, Figure 8. The addition of TES allows solar generation during the day to be shifted into the early evening and reduce the peak net load at higher penetration levels. As a result, the times with scarcity prices do not shift as much as in the PV case and solar generation remains high during times with scarcity prices. The end result is that the capacity value of CSP_6 remains relatively high over all penetration levels considered and only begins to meaningfully decline above 10% penetration.

In contrast to the steeply declining capacity value of PV and CSP_0 at high penetration levels, the capacity value of wind is relatively stable with increasing penetration for two reasons: first, the low capacity credit of wind means that even as wind is added, the times with the peak loads and scarcity prices largely remain the same times even as penetration increases. Second, while wind is not producing a significant amount during times with peak loads and scarcity prices, many wind sites are producing a small amount. Adding more wind sites that have a small probability of producing power during these times keeps lowering the total peak net load slightly with increasing penetration. As a result the small capacity credit of wind is maintained even with high wind penetrations.

The marginal energy value of PV and CSP_0 also decline at a faster rate than the marginal energy value of wind. As a result, at 15% penetration, the energy value of PV and CSP_0 is less than the energy value of wind. The lower energy value for PV and CSP_0 at 15% penetration can be explained in part by the fact that in some hours of the year (<2% of the hours in a year) incumbent coal resources are dispatched to less than their nameplate capacity, while incumbent coal is found to be always at its full capacity with 15% wind. In particular, as PV and CSP_0 increases, incumbent coal tends to be dispatched down in winter and spring months during early morning hours on weekends when solar generation increases faster than the morning load picks up. The displacement of coal increases further with higher PV and CSP_0 penetration, and coal begins to be dispatched down with wind at 20% penetration. By 30% penetration, the incumbent coal is found to be dispatched below their nameplate capacity 5% of the year with wind and over 25% of the year with PV and CSP_0. The energy value of VG decreases when coal is displaced due to the lower full load variable cost of energy from coal ($27/MWh) relative to the full load variable cost of energy from CCGT resources ($46–52/MWh).

The energy value of CSP_6 on the other hand, remains greater than or equal to the fully loaded cost of energy from a CCGT resource even at 30% penetration. The decrease in the total marginal value of CSP_6 with increasing penetration is due to the declining capacity value after a penetration of 10%. As described earlier in Section 4.1, increasing penetrations of CSP_6 begin to reduce price spikes and involuntary

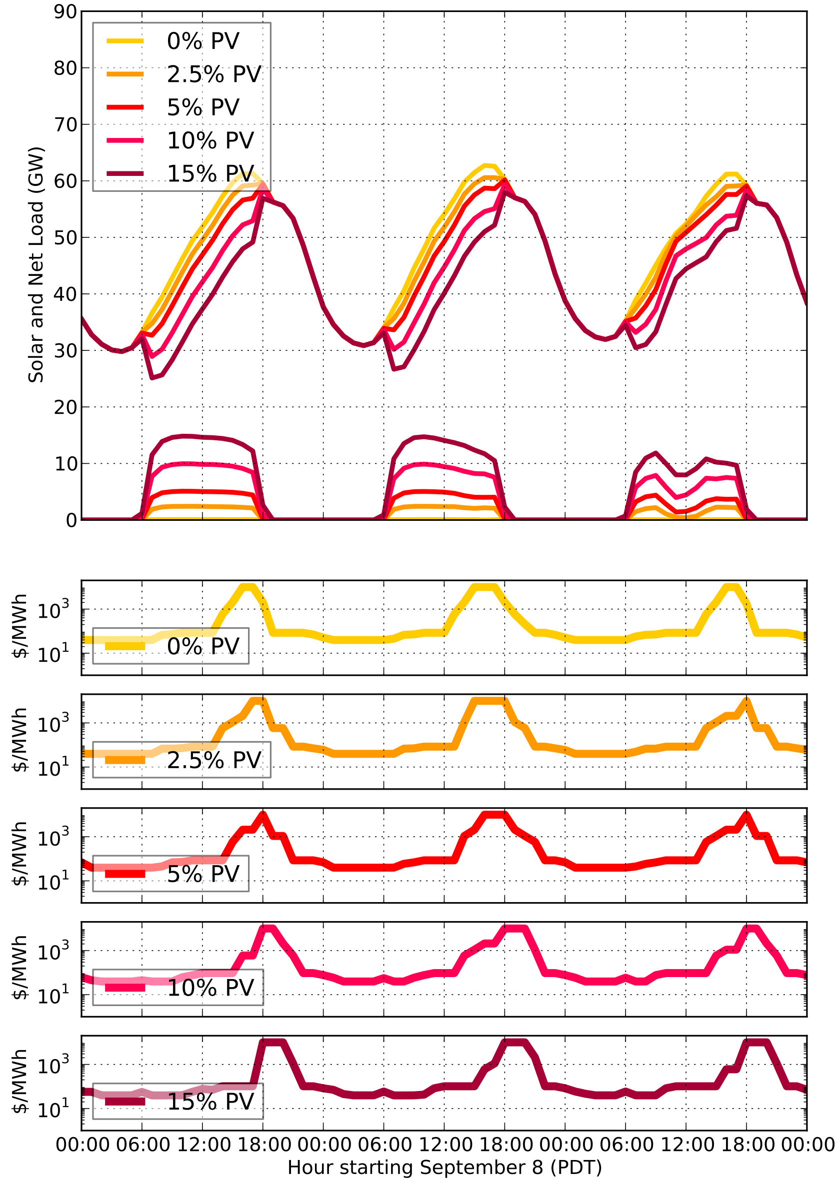


Figure 7: Historical load less the generation from PV and hourly energy prices on three peak load days with increasing PV penetration.

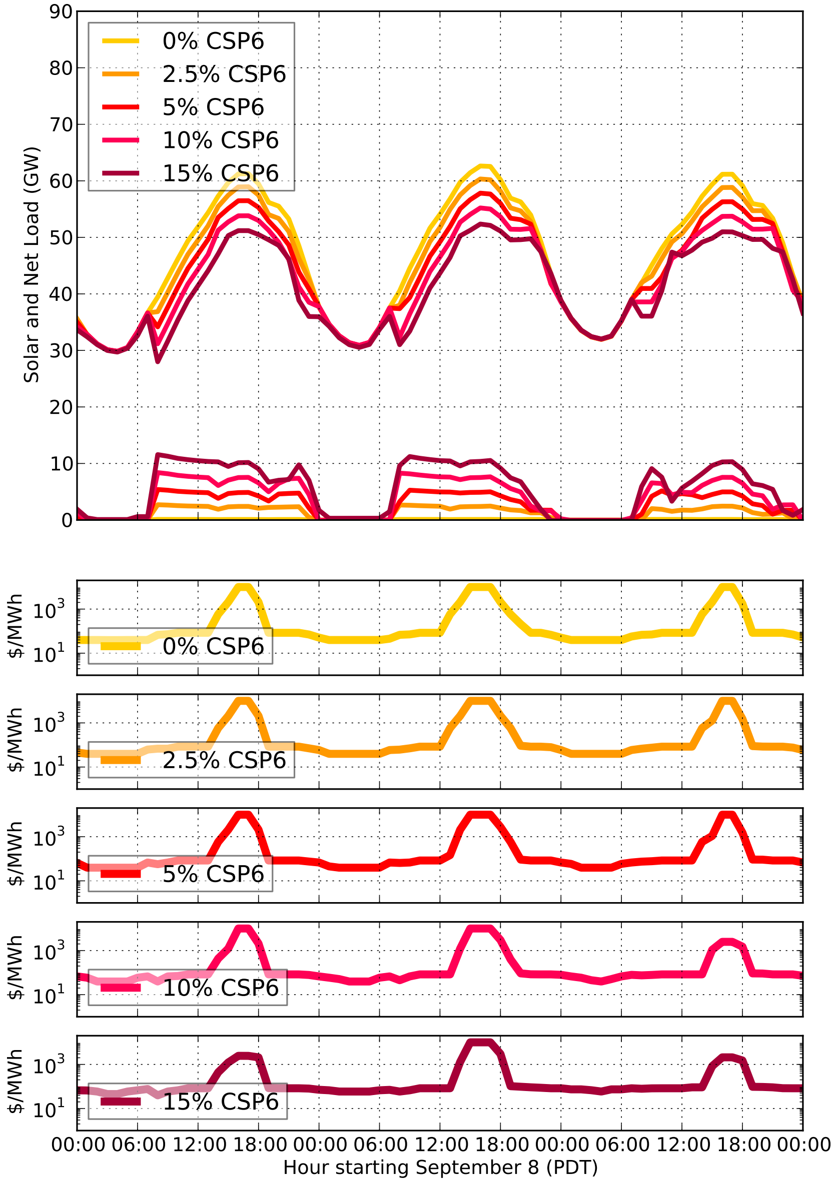


Figure 8: Historical load less the generation from CSP_6 and hourly energy prices on three peak load days with increasing CSP_6 penetration.

load shedding as the penetration increases above 10%. This decreases the need to build new conventional capacity to meet peak loads in the summer. At the same time, reducing the amount of new generation capacity that is built starts to lead to a situation where the lower conventional capacity and the lower solar production in the winter months becomes the most constrained time for the power market. The constraints are not due to insufficient generation capacity but due to insufficient energy. Either way new conventional capacity is needed to balance the available generation and demand. This particular result depends on how much energy is available from hydropower and the CSP_6 in winter months, factors that would not normally be considered in reliability based studies that focus primarily on periods with peak loads. As the penetration of CSP_6 increases, the shift from a capacity-constrained to an energy-constrained system causes the capacity value to begin to decrease at these high penetration levels.[9] Eventually the value of CSP_6 is found to be lower than the average DA wholesale price.[10] Even at 30% penetration, however, the marginal economic value of CSP_6 is found to be well above that of wind (+$14/MWh) and of PV and CSP_0 (+$45/MWh and +$50/MWh).

In sum, the main contributor to the decline in the marginal economic value of wind, PV, and CSP_0 are changes in the capacity value for penetrations between 0% and 10% and changes in the energy value with greater penetration. The change in capacity value at low penetration can lead to a decrease on the order of $24–37/MWh in the value of PV and CSP_0 and a decrease on the order of $7/MWh for wind. The change in the energy value between 10% penetration and 20% penetration can decrease the value of PV and CSP_0 by $8–13/MWh, while the change in the energy value between 10% and 40% can decrease the value of wind by $8/MWh. The cost of DA forecast errors do not dramatically increase with increasing penetration, but they are not negligible at $2–6/MWh. The cost of ancillary services, given the assumed AS procurement rule, are consistently less than $2/MWh for wind, PV, and CSP_0. Because of TES, CSP_6 is able to avoid—to some degree—many of these factors that otherwise drive down the marginal economic value of VG. As a result, especially at high penetration, the marginal economic value of CSP_6 is considerably higher than for the other resources considered.

4.4 Sensitivity Cases

To explore the sensitivity of these results to a small subset of important parameters, four sensitivity cases were developed:

- **No operational constraints:** Relax major operational constraints in the dispatch model to quantify the impact of operational constraints on the marginal economic value of PV.

- **Carbon cost:** Increase the cost of energy through a price on carbon to illustrate the sensitivity of the marginal value of PV to inclusion of one type of externality.

[9] The changing dispatch of the incumbent generation capacity, including the increasing capacity factor of CTs in the winter months described in Section 4.1.2, may in part explain the slight increase in the energy value of CSP_6 at 15% penetration.

[10] We tested whether there is notable value in increasing the size of the thermal storage at higher penetration levels. We found that increasing the thermal storage from 6 hours to 10 hours of thermal storage with the same sized solar field as used in the CSP_6 cases (a solar field multiplier of 2.5) only increased the value by $1–2/MWh relative to CSP_6 at 20% penetration. In contrast, increasing the thermal storage to 10 hours and simultaneously increasing the solar field size (a solar field multiplier of 3) increased the value by about $8/MWh relative to CSP_6 at 20% penetration. The increase in value was due to an increase in capacity value and energy value and a small decrease in the DA forecast error cost. Additional research on how the optimal thermal storage and solar field multiplier change depending on penetration (and deployment of other VG resources) is an area where additional research should be conducted.

- **Cost of capacity:** Reduce the cost of capacity from conventional resources to demonstrate the impact of lower capital costs for CTs and the shifting of new investments toward CTs instead of CCGTs.
- **No retirements:** Assume that plants do not have a technical life and therefore that no plants that exist today will retire by 2030 for technical reasons. This tests the sensitivity of the marginal economic value to the assumption about the technical life of incumbent plants.

4.4.1 No Operational Constraints

The dispatch without operational constraints resembled a pure-merit order dispatch because power plants were assumed to be able to startup and shutdown without cost, ramp between zero output and full generation at any rate, and not experience part-load efficiency penalties related to low output levels. Furthermore any unit was assumed capable of providing each type of reserves. Hydropower was assumed to no longer be restricted by a minimum flow constraint.

Though this unconstrained case is not a realistic representation of the power system, the difference in the marginal economic value of VG between the un-constrained sensitivity case and the reference case with the operational constraints indicates the importance of modeling such constraints.

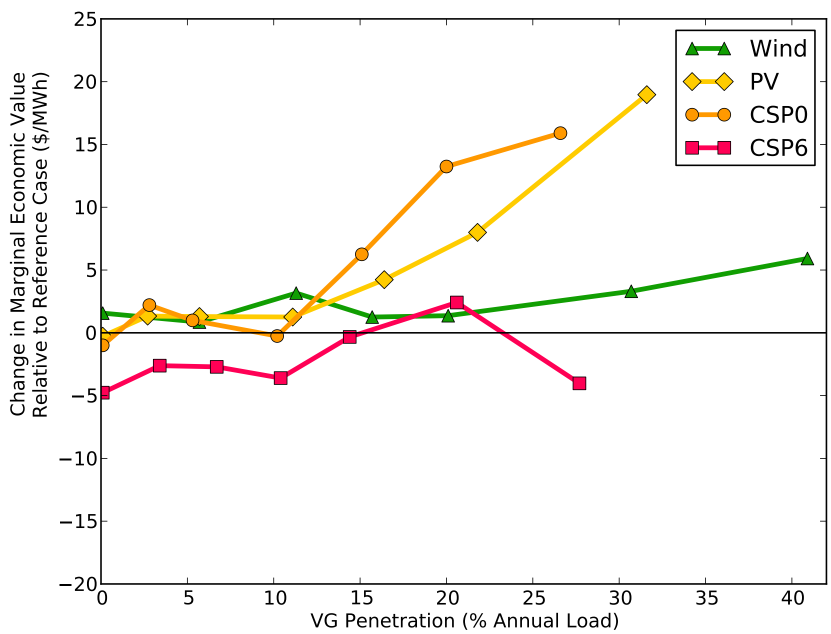


Figure 9: Difference in marginal economic value of variable generation between a case where the operational constraints for thermal and hydropower generation are ignored and the reference case.

At low penetration levels, the no constraints case only modestly increases the value of PV at low penetration. The initial decrease in the marginal value of PV and CSP_0 shown in Figure 6 would still occur even if the system were perfectly flexible.

On the other hand, at high penetration levels the relative difference in the marginal economic value for PV and CSP_0 between the no constraint and reference case is large and far exceeds the cost of the DA forecast errors. This suggests that operational constraints that might impact energy value, such as the thermal generator ramp rate limits and minimum generation constraints, are important for understanding the decline in the value of PV and CSP_0 at very high penetration levels (>20% penetration or so).

4.4.2 Carbon Cost

Adding a $32/tonne CO_2 carbon cost in the model increases the variable cost of thermal generation and therefore increases the energy value of VG. The only noticeable change in the value of PV in the carbon cost case comes in the form of an increase in the energy value of about $13/MWh at low penetration and $9–$11/MWh at higher penetrations. The increase in energy value is similar to the increase that would be expected based on the avoided emission rates reported in Table 8.

4.4.3 Cost of Capacity

The cost of capacity is an important driver of the capacity value of solar. Reducing the cost of new gas-fired CTs from $194/kW-yr in the reference case (based on the capital cost used in WECC studies) to $139/kW-yr in the sensitivity case (based on the lower cost from recent capacity market auctions in PJM) results in a change in investments from only CCGTs to mixture of new CTs and new CCGTs in this sensitivity case. Reducing the cost of CTs also results in shorter periods with scarcity prices and therefore a lower capacity value for all VG technologies, though it impacts solar the most. The capacity value of a flat block decreases from $20/MWh in the reference case to $16/MWh in the case with the lower cost of capacity. The capacity value of PV at 0% penetration decreases by $7/MWh.

Nevertheless, the impact of the lower cost of capacity on the total marginal economic value of VG is somewhat ambiguous: even though the lower cost of capacity decreases the capacity value of VG, the overall change in the marginal economic value is small due to an opposing increase in the energy value. CTs have a worse heat rate than CCGTs, which leads to higher energy costs during the increasing times when CTs are dispatched. The increase in the dispatch of less efficient generation increases the energy value of VG by $4–$6/MWh at low penetration.

4.4.4 No Retirements

Without retirements of existing generation due to plants reaching the end of their technical life, significantly more incumbent natural gas steam turbines along with additional older CTs and CCGTs are available in 2030 than in the reference case. At 0% VG penetration in the no retirements case a portion of this incumbent natural gas steam turbine capacity was found by the model to retire for economic reasons because the short-run profits of these incumbent generators were insufficient to cover their assumed fixed O&M cost; in the reference case, no economic retirements were found to occur. In this sensitivity case the cost of capacity effectively becomes the assumed fixed O&M cost of natural gas steam turbines that retire for economic reasons (about $66/kW-yr) which is much lower than in the reference case where the cost of capacity is similar to the cost of new CCGTs (about $200/kW-yr).

As a result, at low penetration levels, the capacity value of VG is lower in the no retirements case than it is in the reference case. The energy value, on the other hand, is somewhat higher since VG generation displaces energy from less efficient plants. How these two opposing trends impacts the total value of VG depends on the VG penetration level and technology, Figure 10.

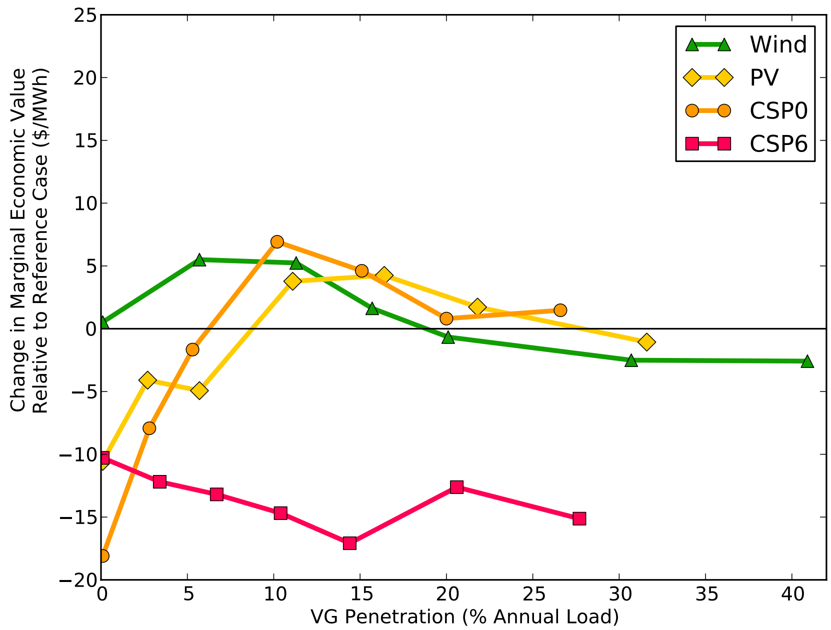


Figure 10: Difference in marginal economic value of variable generation between a case without retirements of existing generation and the reference case where generation is retired after a technical life.

At low penetration levels for solar, the net result is that the value of solar in the no retirements case is lower than it is in the reference case, Figure 10. At 10% and 15% penetration, however, the higher energy value of PV and CSP_0 leads to a net greater value than the reference case. At 20% and 30% penetration the value of PV and CSP_0 in the no retirements case is about the same as the value in the reference case. The value of CSP_6 in the no retirements case remains below the value in the reference case at all penetration levels. The reason is that although the energy value of CSP_6 increases relative to the reference scenario, the capacity value of CSP_6 decreases by a larger amount across all penetration levels. The value of wind is greater in the no retirements case for penetration levels of 15% and below but becomes slightly less valuable at higher penetration levels. Overall, these results suggest that the value of VG can be relatively sensitive to assumptions about retirements.

5 Conclusions

Understanding the economic value of variable generation is important for making long-term decisions about renewable procurement and supporting infrastructure. This paper uses a unique modeling framework that captures both long-run investment decisions as well as dispatch and operational constraints in order to understand the long-run marginal economic value of wind, PV, and CSP with and without thermal energy storage and how that value changes with increasing penetration levels. Though the model only captures a subset of the benefits and costs of renewable energy, it provides unique insight into how the value of that subset changes with technology and penetration level. Pollution emissions were not the focus of this analysis, and as such we did not include the impact of many emissions related policies, though emissions were estimated as a byproduct of the investment and dispatch decisions. The decrease in emissions of CO_2, NO_x, and SO_2 with increasing penetration of variable generation illustrates that there are additional benefits of variable generation that were not monetized in this analysis.

The results from this case study implementation of the model demonstrate that the narrowly-defined economic value and changes in economic value with increasing penetration differ among variable renewable technologies. Not only does the economic value vary by renewable energy technology and penetration but the ordering of renewable energy technologies based on marginal economic value also change with penetration. The magnitude of these variations suggests that investors, resource planners, and policy makers should carefully consider the economic value and relative differences in the economic value among renewable energy technologies when conducting broader analyses of the costs and benefits of renewable energy. Nor should these evaluations be static—as renewable energy penetration increases new analysis will be needed. Also important is identifying ways to minimize the decline in value of variable renewable energy with penetration. Though that has not been the focus of the present work, by decomposing changes in economic value into capacity value, energy value, day-ahead forecast error and AS costs the present work can inform future analysis of these mitigation options. This analysis can also inform the design of simplified renewable procurement and transmission planning tools by illustrating the relative importance of changes in the economic value of VG with increasing penetration to other factors that would be included in the simplified tools. The change in the value of PV and CSP_0 with increasing penetration should be given particular attention in such tools. More specifically, the key conclusions from this case study assessment of California include the following:

- *Solar has high value at low penetration:*

  The marginal economic value of solar at low penetration levels is high in California. This high value at low penetration is largely due to the ability of solar resources to reduce the amount of new non-VG capacity that is built, leading to a high capacity value. The magnitude of the capacity value of solar resources depends on the coincidence of solar generation with times of high system need, the cost of generation resources that would otherwise be built, and decisions regarding retirement of older, less efficient conventional generation.

- *There is little apparent value to thermal storage at low solar penetration:*

  At low penetration levels in California, we find that there is no strong increase in value per unit of electricity associated with adding TES to CSP plants. TES may be justified for minimizing the levelized cost of CSP plants, but there is no clear evidence in the present analysis that it is required to maximize economic value at low solar penetration.

- *The value of PV and CSP without thermal storage drop considerably with high penetration:*

  Without any mitigation strategies to stem the decline in the value of solar, the value of PV and CSP_0

drop considerably with increasing penetration. For penetrations of 0% to 10% the primary driver of the decline is the decrease in capacity value with increasing solar generation. Additional PV and CSP_0 are less effective at avoiding new non-VG capacity at high penetration than at low penetration. For penetrations of 10% and higher the primary driver of the decline is the decrease in the energy value. At these higher penetration levels additional PV and CSP_0 start to displace generation with lower variable costs. The operational constraints of thermal generation and hydropower contribute to the declining energy value of PV and CSP_0 at high penetration levels. At 20% solar penetration and above, there are increasingly hours where the price for power drops to very low levels, reducing the economic incentive for adding additional PV or CSP_0, and eventually there is curtailment of a portion of the energy generated by those solar technologies. The decline in the value is not driven by the cost of increasing AS requirements and is not strongly linked to changes in the cost of DA forecast errors.

- *At medium to high penetration CSP with thermal storage is considerably more valuable relative to PV and CSP without thermal storage:.*

  The value of CSP_6 also decreases at higher penetration levels but not to the extent that the value of PV and CSP_0 decline. As a result, at higher penetration levels the value of CSP with thermal storage is considerably greater than the value of PV or CSP_0 at the same high penetration level. The capacity value of CSP_6 remains high up to penetration levels of 15% and beyond because the thermal energy storage is able to reduce the peak net load even at higher CSP_6 penetration levels. Power system operational constraints are less severe for high penetrations of CSP_6 due to the ability to use thermal energy storage, as modeled in this analysis, to avoid pushing against any such constraints.

- *The value of wind is largely driven by energy value and is lower than solar at low penetration:*

  The value of wind is found to be significantly lower than solar at low penetration due to the lack of correlation or slightly negative correlation between wind and demand or wind and high prices. This lower value of wind is largely due to the lower capacity value of wind and at least for low to medium penetrations of wind the decline in the total marginal economic value of wind with increasing penetration is found to be largely a result of further reductions in capacity value. The energy value of wind is found to be roughly similar to the energy value of a flat block of power (and similar to the fuel and variable O&M cost of natural gas CCGT resources operating at full load). Only at very high penetration levels does the energy value of wind start to drop in the California case study presented here. Operational constraints cause some of the decline in the value of wind, but a large part of the decline in the value of wind is due to the merit-order impact of wind. The DA forecast error costs have little influence on the value of wind at low penetration and remain fairly manageable, on average less than $7/MWh, even at high penetration levels. AS costs are not found to have a large impact on the economic value of wind as modeled in this analysis.

- *At high penetration, the value of wind can exceed the value of PV and CSP without thermal storage:*

  While the marginal economic value of solar exceeds the value of wind at low penetration, at around 10% penetration the capacity value of PV and CSP_0 is found to be substantially reduced leading to the total marginal economic value of PV and CSP_0 being similar to the value of wind. At still higher penetrations, the energy value of PV and CSP_0 fall faster than the energy value of wind leading wind to have a higher marginal economic value than PV and CSP_0. CSP_6 on the other hand, is found to have a considerably higher value than wind at all penetration levels.

These results may, to a degree, be influenced by the fact that the analysis has loosely focused on California. In California, a region characterized by considerable natural gas fired generation, substantial hydropower generation, and diversity in potential wind resource sites, the dominant factors in understanding the economic value of wind and solar with increasing penetration levels are changes in the energy and capacity value of these sources. Analysis tools and methods for understanding economic value must therefore be able to adequately represent factors affecting resource adequacy and the merit-order stack of resources. Analysis, especially at high penetration, should also characterize conventional plant operational constraints like ramp-rates and start up costs. In regions outside of California that lack as much flexible gas and hydropower, consideration of operational constraints will be even more important.

Characterizing the impact of DA forecast errors and ancillary service requirements adds significant complexity to the analysis. Though the model used in this analysis relied on several simplifications, including commitment and dispatch decisions based on vintages rather than individual units and perfect foresight in the RT, the overall results indicate that the economic impact of DA forecast errors and AS requirements do not change as dramatically with increasing penetration and are a second order cost in the case of AS. That said, the actual amount of AS and the amount of flexibility required to manage DA forecast errors do increase with increasing VG penetration. Even though the economic impact may not be very large per unit of renewable energy, managing DA forecast errors and procuring adequate AS are both extremely important for ensuring system reliability and should continue to receive significant attention in studies of the steps necessary to ensure the technical feasibility of increasing variable generation penetrations.

One of the most important results from this work is the high capacity value of solar at low penetration and the decline in that capacity value (with the exception of CSP_6) with penetration levels around 10% on an energy basis. Given the importance of capacity value to the value of solar, areas of research that should be explored further include the ability of solar to contribute to resource adequacy, how that contribution changes with increasing penetration, and the economic implications of the decreasing contribution with increasing penetration. The capacity credit of PV and CSP_0 at increasing penetration levels should be investigated in more detail using detailed LOLP models to complement the less detailed, economic-focused analysis used here. In addition, as flexibility of generation resources becomes more important with increasing penetration of variable generation, methods to incorporate measures of flexibility into adequacy studies may also need to be developed. The capacity credit for CSP_6 should also be investigated further at high penetration levels. Based on the results presented here, however, energy constraints appear to impact the ability of CSP_6 to reduce the need for new generation capacity suggesting that methods used to evaluate the capacity credit of CSP_6 should be based on those suited to evaluating the capacity credit of resources in energy-constrained systems (e.g., methods used to evaluate resource adequacy in a system dominated by hydropower).

Another important finding of the present work is that the long-term value of adding TES to CSP is only obvious at higher penetration levels where the energy and capacity value of CSP_0 and PV fall off much faster than the value of CSP_6. Based on these results, TES should be especially considered by resource planners, solar manufacturers, and project developers for regions where the penetration of solar is expected to become substantial. Additional research is needed to assess whether this finding holds for power systems that differ from the one studied here. Research to explore the value of thermal storage in helping to manage

DA forecast errors and AS increases caused by other VG technologies is also warranted.

Though this study focused on California and just one variable generation technology at a time, the same framework can be used to understand the economic value of variable generation in other regions and with different combinations of renewable energy. In a future paper, the same framework will be used to evaluate how changes in the power system, like price responsive demand, more flexible thermal generation, and lower cost bulk power storage, might impact the value of variable generation. Each of these "mitigation strategies" might help slow the decline in the marginal economic value of variable generation found in this paper. Ultimately, it is not possible to precisely know the long-run value of variable generation due to numerous sources of uncertainty, including future regulatory policies, future fuel prices, and future investment costs of conventional technologies. Analysis models like the one presented in this paper, however, can help identify promising routes forward and inform decisions.

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