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Technical Report
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November 2013

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Foreword

This report is one of a series stemming from the U.S. Department of Energy (DOE) Demand Response and Energy Storage Integration Study. This study is a multi-national-laboratory effort to assess the potential value of demand response and energy storage to electricity systems with different penetration levels of variable renewable resources and to improve our understanding of associated markets and institutions. This study was originated, sponsored, and managed jointly by the DOE Office of Energy Efficiency and Renewable Energy and the DOE Office of Electricity Delivery and Energy Reliability.

Grid modernization and technological advances are enabling resources, such as demand response and energy storage, to support a wider array of electric power system operations. Historically, thermal generators and hydropower in combination with transmission and distribution assets have been adequate to serve customer loads reliably and with sufficient power quality, even as variable renewable generation, such as wind and solar power, have become a larger part of the national energy supply. While demand response and energy storage can serve as alternatives or complements to traditional power system assets in some applications, their values are not entirely clear. This study seeks to address the extent to which demand response and energy storage can provide cost-effective benefits to the grid and to highlight institutions and market rules that facilitate their use.

The project was initiated and informed by the results of two DOE workshops: one on energy storage and the other on demand response. The workshops were attended by members of the electric power industry, researchers, and policymakers, and the study design and goals reflect their contributions to the collective thinking of the project team. Additional information and the full series of reports can be found at www.eere.energy.gov/analysis.

Acknowledgments

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List of Acronyms

AC	alternating current
CAISO	California Independent System Operator
CC	combined-cycle gas turbine
CO_2	carbon dioxide
CSP	concentrating solar power
DOE	U.S. Department of Energy
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GW	gigawatt
GWh	gigawatt-hour, energy
GW-h	gigawatt-hour, reserves
MISO	Midwest Independent System Operator
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour, energy
MW-h	megawatt-hour, reserves
NREL	National Renewable Energy Laboratory
PV	photovoltaic
TEPPC	Transmission Expansion Planning Policy Committee
TW	terawatt
TWh	terawatt-hour, energy
VOM	variable operations and maintenance
WECC	Western Electricity Coordinating Council

Abstract

Electricity storage technologies can potentially act as an enabling technology for increased penetration for variable generation (VG) sources, such as solar and wind. However, storage technologies ultimately have to be justified in terms of their economic benefits compared to their costs. One of the challenges faced by storage developers is quantifying the value of energy storage, especially considering changes in the generation mix, including additional VG deployment.

This analysis used a commercial grid simulation tool to evaluate several operational benefits of electricity storage, including load-leveling, spinning contingency reserves, and regulation reserves. A series of VG energy penetration scenarios from 16% to 55% were generated for a utility system in the western United States. This operational value of storage (measured by its ability to reduce system production costs) was estimated in each VG scenario, considering provision of different services and with several sensitivities to fuel price and generation mix. Overall, the results found that the presence of VG increases the value of energy storage by lowering off-peak energy prices more than on-peak prices, leading to a greater opportunity to arbitrage this price difference. However, significant charging from renewables, and consequently a net reduction in carbon emissions, did not occur until VG penetration was in the range of 40%–50%. Increased penetration of VG also increases the potential value of storage when providing reserves, mainly by increasing the amount of reserves required by the system.

Despite this increase in value, storage may face challenges in capturing the full benefits it provides. Due to suppression of on-/off-peak price differentials, reserve prices, and incomplete capture of certain system benefits (such as the cost of power plant starts), the revenue obtained by storage in a market setting appears to be substantially less than the net benefit (reduction in production costs) provided to the system. Furthermore, it is unclear how storage will actually incentivize large-scale deployment of renewables needed to substantially increase VG penetration. This demonstrates some of the additional challenges for storage deployed in restructured energy markets.

Further analysis is required to evaluate both the value and potential revenue of energy storage in evolving market structures. In addition, there are several additional sources of value that have not been quantified in detail, such as the benefits of siting storage on distribution networks and additional payments that might be received for storage providing fast-response regulation services or other new services that may accompany large-scale deployment of renewable energy.

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1 Introduction

A key driver behind large-scale deployment of energy storage may be the increased use of renewable energy sources, such as solar and wind energy. Solar and wind energy are both variable and uncertain resources, whose supply of energy has limited coincidence with normal demand for electricity. Increased use of these variable generation (VG) resources could potentially increase the economic value of energy storage.

This study is an extension of a previous analysis of storage in a simulated grid system (Denholm et al. 2013). This previous analysis simulated a grid largely dominated by conventional fossil resources. It evaluated the value of energy storage by comparing the annual production cost with and without storage, with the difference attributed to the added storage device. It evaluated the use of storage for both energy arbitrage/load leveling and provision of operating reserves.

The previous study found four major conclusions:

1. The value of energy arbitrage is relatively low and by itself is unlikely to yield a positive cost-benefit ratio for most existing storage technologies.
2. Operating reserves, such as regulation and contingency reserves, provide a higher value and require devices with much lower energy storage capacities,[1] yielding more favorable economics. However, the overall market size for these services is relatively small, and under a market setting the price for reserves can be collapsed with a relatively small amount of storage.
3. The ability of storage to replace or defer investment in traditional generation, transmission, or distribution assets is an important source of benefits that is not captured when considering only its operational value.
4. In market settings, the revenue storage devices can earn may be lower than the overall operational savings they provide to the power system.

The purpose of this further analysis is to examine how the value proposition for energy storage changes as a function of VG penetration. It uses the same grid modeling approach as was used in the previous study, comparing the operational costs of an electric power system both with and without added storage. It creates a series of scenarios with increasing VG penetration and examines how the value of storage changes. It also explores the mechanisms behind this change in value, including the change in on-peak and off-peak price differentials and the cost of operating reserves created by increased penetration of wind and solar energy.

[1] Specifically, a device providing operating reserves can potentially need 1 hour or less of continuous discharge capacity while a device providing energy arbitrage may need several hours of capacity (Akhil et al. 2013).

2 The Potential Impact of Renewable Energy on Energy Storage Value

There are a number of mechanisms by which the addition of VG potentially increases the value of energy storage. For the purposes of this study, we consider two general categories of storage benefits: energy shifting and reserves provision.

Energy shifting represents the ability of storage to levelize the net load[2] on the system, charging during periods of lower demand using lower-cost baseload resources (potentially including renewable energy sources) and discharging during periods of higher demand to avoid the operation of higher-cost units. It also includes the ability to avoid startup and shutdown of thermal generators. The ability of energy storage to shift timing of generation and increase economic efficiency of the grid is a well-understood source of value. The value of energy storage in this application is largely dependent on the cost difference between units that generate during off-peak and on-peak periods. The potential impact of VG resources is to decrease off-peak prices more than it decreases on-peak prices, increasing the price spread able to be arbitraged by energy storage. With sufficient penetration of VG, the limits of grid flexibility can result in curtailed energy, creating significant opportunities to store this zero-fuel-cost resource (Denholm and Hand 2011). Furthermore, the increase in variability of net load due to VG can increase the frequency (and cost) of power plant starts.

A second potential impact of VG on the value of storage is the change in operating reserves requirement. Operating reserves requires power plants to rapidly vary output in response to system contingencies or other short-term variation in net load. The addition of VG increases the total reserves requirements, which could increase the cost of total reserves and the overall size of the market for reserves.

Analysis of the value of energy storage providing both load-leveling/arbitrage and reserves is often performed using historic market data.[3] However, it is difficult to use historic data to evaluate the impact of renewables because the introduction of VG would fundamentally affect market prices and system operations. Understanding the changes in operation due to renewables typically requires simulations using detailed grid models. These models simulate the dispatch of the power plant fleet in a given area and how this dispatch would change when adding VG. The simulations determine which plants would be available and used for charging energy storage during off-peak periods or displaced by energy storage discharge during peak periods. The simulations can also determine the storage dispatch strategy that would minimize overall generation cost, including the ability to avoid power plant starts.

Zucker et al. (2013) provides a comprehensive literature review of storage value studies, including several that analyze the impact of VG on the storage using production cost models. Examples of previous analysis that found an increase in storage value as a function of wind penetration includes Sioshansi (2011) who used a supply function equilibrium model to examine

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[2] We use the term net load to refer to the normal demand for electricity minus the contribution from usable solar and wind. The net load becomes the load met by utilities or system operators using conventional generation assets.

[3] A literature review of U.S. studies using market data is provided by Denholm et al. (2013), and a more comprehensive review of international studies is provided by Zucker et al. (2013).

the impact of wind on energy prices and energy storage value. Tuohy and O'Malley (2011) used a stochastic unit commitment/economic dispatch model to examine several scenarios of increased wind penetration on the benefits and economic value of storage in the Irish grid system. The study demonstrates an increase in value of storage as a function of penetration, although significant economic benefits (and carbon reductions) do not occur until very high penetration of wind (greater than 40%) is achieved. EPRI (2013) performs a detailed simulation of the value of pumped hydro in the Western U.S., using the UPLAN production cost model. It demonstrates increased value associated with plant upgrades to improve their flexibility, including the value of providing additional reserves services in response to greater VG penetration.

There are other sources of storage value, such as the ability to replace or defer generation, transmission, distribution investment (which we describe in this document as "capacity benefits"). The value of these applications may also be impacted by the deployment of VG resources, such as the case where additional transmission is needed to access remote wind resources, and storage could potentially increase the utilization of these new resources (Denholm and Sioshansi 2009). These sources of value are not evaluated in this report, and additional analysis is needed to evaluate the benefits of these and other services, including the ability of storage to address forecast errors and the increased deployment of operating reserves that may occur under high VG penetration scenarios.[4]

[4] Further discussion of some of these issues is provided by Tuohy and O'Malley (2011) who use stochastic unit commitment model to examine the value of energy storage in addressing wind forecast errors.

3 Case Study

To evaluate the impact of VG on the value of energy storage, we developed a test case composed of two balancing areas largely in the State of Colorado and described previously (Hummon et al. 2013; Denholm et al. 2013). The Colorado test system uses data derived from the database established by the Western Electricity Coordinating Council (WECC) Transmission Expansion Policy Planning Committee (TEPPC) model and other publicly available datasets (TEPPC 2011). Projected generation and loads were derived from the TEPPC 2020 scenario. Hourly load profiles were based on 2006 data and scaled to match the projected TEPPC 2020 annual load. Hourly solar and wind power generation profiles are time synchronized to the load profiles for the year 2006. The system peaks in the summer with a 2020 coincident peak demand of 13.7 GW and annual demand of 79.0 TWh. A total of 201 thermal and hydro generators are included in the test system, with total capacities listed in Table 1. Also of note is the fact that the system already has about 560 MW of pumped hydro storage, which reduces the value of additional storage.[5]

Table 1. Test System Generator Capacity

	System Capacity (MW)
Coal	6,178
Combined Cycle (CC)	3,724
Gas Turbine/Gas Steam	4,045
Hydro	773
Pumped Storage	560
Other[a]	513
Total	**15,773**

[a] Includes oil- and gas-fired internal combustion generators

Fuel prices were derived from the TEPPC 2020 database. Coal prices were $1.42/MMBtu for all plants. Natural gas prices varied by month and range from $3.90/MMBtu to $4.20/MMBtu, with an average of $4.10/MMBtu. This is lower than the EIA's 2013 Annual Energy Outlook projection for the delivered price of natural gas to the electric power sector in the Rocky Mountain region of $5.3/MMBtu in 2020 (EIA 2013).We also evaluated a scenario where natural gas prices were doubled for all units (to an average price of about $8.2/MMBtu). No constraints or costs were applied to carbon or other emissions. The system was modeled zonally, with no transmission constraints within each zone. This ignores the value of storage providing congestion relief or deferring investments in transmission capacity (Akhil et al. 2013). The modeled scenario assumes sufficient new transmission capacity is constructed to access various wind and solar resources without any additional congestion.

A series of VG penetration scenarios were developed, ranging from 16% to 55% on an energy basis in approximately 5% increments, with an approximately 5.5:1 ratio of wind to solar on an energy basis. In the lowest scenario, we added 3,347 MW of wind with 10.7 TWh of generation and 878 MW of solar PV with 1.8 TWh of annual generation. For comparison, Colorado received about 11% of its electricity from wind in 2012.[6] PV profiles were generated using the System Advisor Model (SAM) (Gilman and Dobos 2012) with 2006 meteorology. Wind data was derived from dataset prepared for the Western Wind and Solar Integration Study (WWSIS)

[5] The specific impact of this existing storage is discussed in Denholm et al. (2013).
[6] Colorado generated 6,045 GWh from wind in 2012 compared to total generation of 53,594 GWh (EIA 2013).

(GE Energy 2010). In each scenario, discrete wind and solar plants were added from the WWSIS datasets until the installed capacity produced the targeted energy penetration.[7] To evaluate the impacts of storage consistently, no other changes were made to the generation mix; however, sensitivity to plant retirements is considered in Section 4.2

We generated hourly requirements for contingency, regulation, and flexibility reserves.[8] Contingency reserves are based on the single largest unit (an 810 MW coal plant), with 50% met by spinning units. Regulation and flexibility reserve requirements vary over time based on the statistical variability of load, wind, and PV (Ibanez et al. 2012).[9] We do not simulate the dynamic behavior associated with reserve provision, which could potentially increase the value of fast response energy storage.

Hummon et al. (2013) describes in detail the application of the reserves calculation methodology to the test system. They also describes assumptions regarding the availability and constraints of individual generators providing reserves, which is a major driver for the cost of providing reserves, and therefore for the value of energy storage providing reserves. Table 2 summarizes the various VG scenarios, including total capacity and reserve requirements.

Table 2. VG Scenarios Evaluated

VG Energy Penetration (%)	Renewable Capacity (MW)		Annual Upward Reserve Requirements (GW-h)[a]	
	Wind	PV	Flexibility	Regulation
16.0%	3,347	986	502	1,050
20.9%	4,255	1,336	600	1,134
27.2%	5,515	1,649	769	1,281
32.2%	6,588	1,999	855	1,364
35.8%	7,216	2,301	918	1,422
40.3%	8,386	2,574	1,096	1,626
44.9%	8,562	2,898	1,183	1,702
49.0%	9,948	3,211	1,304	1,835
52.5%	10,485	3,461	1,456	2,091
55.8%	11,292	3,761	1,511	2,140

[a] The unit "GW-h" represents a unit of capacity (GW) held for one hour.

The simulations performed in this analysis used the PLEXOS production cost model with day-ahead unit commitment and hourly economic dispatch with a 48-hour optimization window,

[7] We used discrete plants from the WWSIS datasets, which results in additions not exactly equal to 5%. The sites were chosen based on capacity factor and do not necessarily reflect existing or planned locations for wind and solar plants.
[8] For additional discussion of these reserves see Ela et al. (2011). Flexibility reserves are not a well defined product. For discussion of proposed flexibility reserves products in CAISO and MISO see Xu and Tretheway (2012) and Navid et al. (2011).
[9] Reserves provision was based on methodology established by the Western Wind and Solar Integration Study Phase 2 (Lew et al. 2013). For these services, only the "upward" (or the ability to increase output from a generator) reserve requirements were evaluated. The need for downward reserves becomes of greater importance at high renewable penetration when conventional thermal generators are operated at or near their minimum generation points for more hours of the year. Additional downward reserve capacity may need to be derived from controlled curtailment of VG sources. Additional analysis is needed to evaluate the cost and price of separate up and down reserve products in these scenarios, and the potential increase in storage value that can result.

rolling forward in 24-hour increments.[10] The extra 24 hours in the unit commitment horizon (for a full 48-hour window) were necessary to properly commit the generators with high start-up costs and the dispatch of energy storage.[11]

For this study, we evaluated three main "classes" of energy storage devices based on the services they can provide:

1. Energy only
2. Reserves only (for both spinning contingency and regulation reserves)
3. Energy and reserves.

The energy-only device was based on the pumped hydro plants in the existing PLEXOS database, however it was modified to resemble a high-energy battery with greater flexibility of operation. Specifically we assumed the device is capable of ramping over its entire range in each 1-hour simulation period interval (with no minimum generation level and the ability to instantaneously switch between charging and discharging).[12] We also assumed a constant efficiency as a function of load and no minimum up or down times. We assumed a rating of 300 MW with 8 hours of storage capacity at full output (2,400 MWh of discharge energy) and a 75% net (AC-AC) round-trip efficiency.[13] No fixed or variable operation and maintenance costs were assigned to the storage device, so these costs would have to be subtracted from the operational values calculated in Section 4. The storage device is co-optimized with other generators to minimize overall production cost. No other changes were made to the system generation mix; however sensitivity to generation mix is considered in Section 4.2. Because the storage device can potentially provide capacity benefits (defined here as the ability to replace or defer conventional generation assets), conventional generation could potentially be removed (Sioshansi et al. forthcoming). However, for consistency we did not remove any of the existing generation.

The reserves-only device represents a highly responsive short duration energy storage device capable of providing regulation or spinning contingency reserves. This represents a battery, flywheel, or other device that meets the local market requirements for providing these services.[14] We assume the device is not ramp constrained and as a result can provide its full output range for reserve products, but the combination of services cannot exceed the total capacity of the device. The base case assumes a 100 MW device, which is smaller than the energy-only device due to the relatively small amount of reserves required in the system. When providing spinning contingency reserves, we assume that the device simply provides up to its full discharge capacity

[10] PLEXOS is one of several commercially available production cost models. A list of publications that describe previous analyses performed with this tool is available at http://energyexemplar.com/publications/
[11] All scenarios were run for one chronological year using PLEXOS version 6.207 R08, using the Xpress-MP 23.01.05 solver, with the model performance relative gap set to 0.5%.
[12] This represents the full usable capacity of the storage device. Additional requirements regarding depth of discharge limits for batteries or other storage devices are not considered.
[13] The round-trip efficiency is based on a sodium-sulfur battery (Nourai 2007).
[14] The energy capacity required varies by product and location. For example, the Midcontinent Independent System Operator (MISO) requires spinning reserves to be restored in 90 minutes, while WECC requires 105 minutes (NERC 2011). For regulation, new tariffs and system operator rules allow devices with 1 hour or less to participate in regulation markets (CAISO 2011).

without incurring any operational costs and do not consider real energy exchanges that occur during a contingency event. For regulation, we also assume the device can provide up to its full capacity and that the service is net-energy neutral in each 1-hour simulation interval. However, even if regulation is net-energy neutral over time, in any given dispatch interval there will be real energy consumed or produced by the storage device. This will produce a net consumption of energy by the storage device due to round-trip efficiency losses. Because we do not simulate the actual dispatch of storage devices providing regulation, we make a set of simplifying assumptions to address the energy consumed. The energy consumed by a device providing regulation is the product of two factors: the fraction of reserve capacity actually used to provide real energy and efficiency losses. The first factor, has been referred to as the "regulation energy use ratio" (Ellison et al. 2012) or the "dispatch to contract ratio" (Kempton and Tomic 2005) and depends on the actual amount of energy that flows through the device when called to provide regulation services, quantified by the regulation signal actually sent to the storage device. This actual energy is multiplied by the loss rate to produce the amount of energy actually consumed by the storage device when providing reserve services. We assume the dispatch to contract ratio is 14% (Ferreira 2013) and the efficiency loss rate is 20%, based on a net round-trip efficiency of 80%.[15] As a result, for each hour, a storage device providing 100 MW of regulation consumes 2.8 MWh of energy. We assume the storage device providing reserves must effectively purchase energy at this rate for "make-up energy" associated with losses while providing regulation reserves.

Finally, we considered a device that can provide both energy and ancillary services, combining the approaches described above, except modifying the approach to losses occurring while providing regulation. A storage device providing real energy can provide regulation without additional charging as long as the regulation capacity provided is equal to or less than its current output. For example, a 100 MW device discharging at 60 MW during 1 hour can also provide up to 40 MW of regulation by operating between 100 MW and 20 MW (equal to 60 MW +/-40 MW) during the same hour. As long as regulation is a net-zero energy service during that hour, the device will provide the same amount of energy, therefore requiring no additional make-up energy.[16] However, any regulation provided that exceeds the average discharge will require make-up energy at the same rate as the reserves-only device. Using the previous example of a 100 MW device discharging at 20 MW, it could provide 20 MW of regulation without any make-up energy and another 60 MW of regulation that would require make-up energy. As with the reserves-only case, these losses were tracked and accounted for by adding in make-up losses separately.

[15] In addition, we also assume that the economic value of energy consumed and produced in each time interval while providing regulation is equal.

[16] This assumption also requires constant efficiency as a function of discharge rate. As with the reserves-only device, the makeup energy calculation uses several simplifying assumptions used to estimate the value of energy storage providing reserves. Additional analysis is required to evaluated the real operation of energy storage providing reserves and constraints imposed by energy limits and the need for down regulation services.

4 Results

4.1 Base Case (Energy-Only Device)

We begin by demonstrating the impact of increased VG penetration on the load-leveling (energy-only) storage device. When considering the results presented throughout this section, it should be noted that while detailed results are presented for each VG scenario, the goal of the analysis was to identify trends in value, as opposed to estimate precise values for storage at each penetration of VG. Figure 1 illustrates the results for the base case scenarios where renewable energy was added in approximately 5% increments (on an energy basis) from 16% to 56% VG. The right axis shows the total annual reduction in production cost, or the overall operational value of adding a 300 MW device, in terms of reducing fuel, starts, and other operational costs. *Throughout this document we define the operational value of energy storage as the difference in total production cost between cases with and without storage.* The left axis shows the value normalized by the capacity of the storage device (to measure device value on a per-kilowatt basis). The figures provide results for both natural gas price cases (about $4.1/MMBtu and $8.2/MMBtu). These results show an increasing value for storage devices, with about a 50% and 90% increase from the lowest to the highest level of VG penetration for the two fuel price cases.

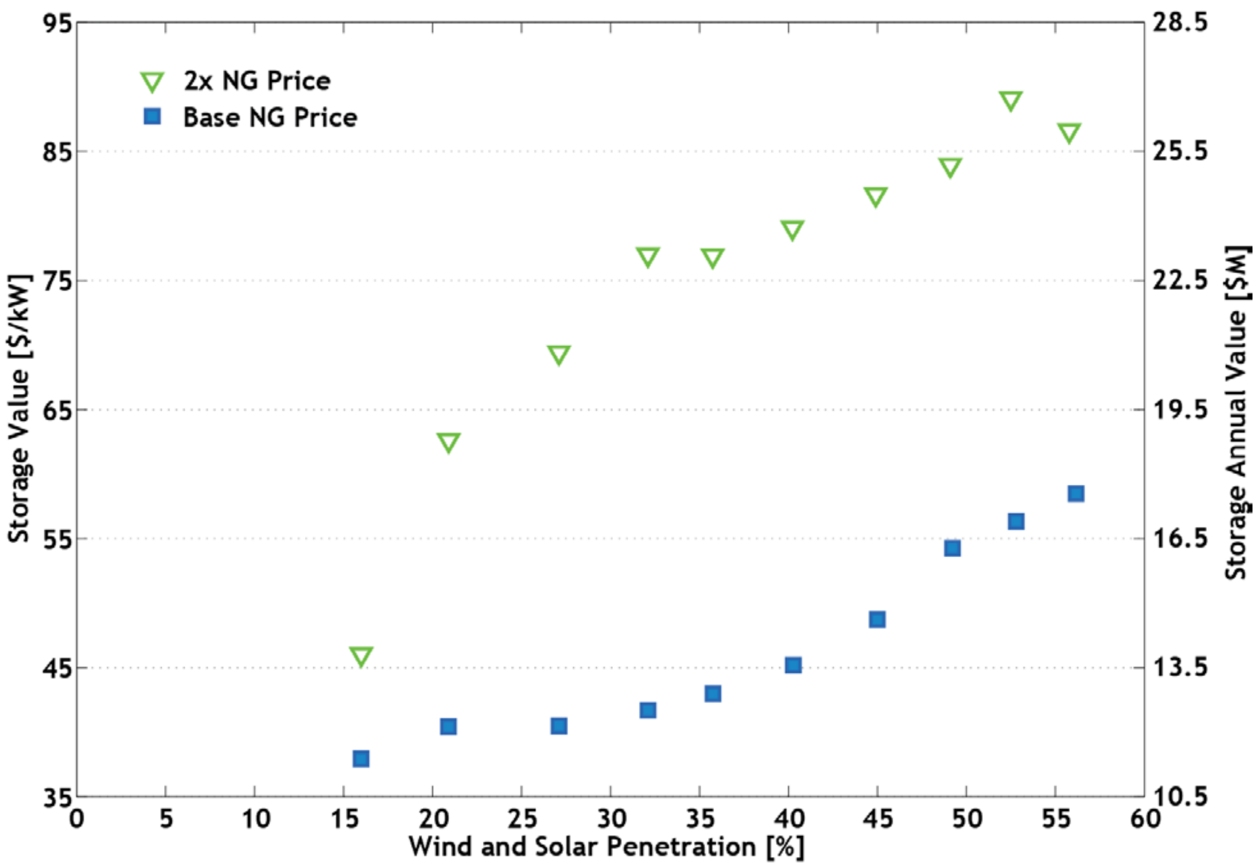

Figure 1. Annual value of a 300 MW energy-only storage device in the analyzed system (where value is defined as the difference in production cost in cases with and without added storage)

The increase in storage value is driven largely by the decrease in off-peak energy used for charging. This can be observed by examining both the source of charging energy and its cost. At low VG penetration, natural gas is the marginal fuel for most hours of the year, despite the very large contribution of coal to the overall generation mix. This can be observed in Figure 2, which is a price-duration curve for the lowest (16%) VG penetration case. Three main zones of prices can be observed. Coal generates at a cost of $18–$24/MWh (mostly at about $20/MWh) and is on the margin (available to increase generation) about 10%–20% of the time. Wind and solar is never at the margin, meaning there is no spare (curtailed) VG able to provide charging at no opportunity cost.[17] When coal generation is available, energy storage charges with coal to displace higher-cost gas-fired generation, typically combined cycle gas turbine (CCGT) units which generate at a cost of about $25–$35/MWh in the low gas price case or $45–$70/MWh in the high gas price case. In the low gas price case this leads to very low arbitrage value, considering the losses in storage. There are also opportunities for storage to displace higher cost, lower efficiency gas- or oil-fired combustion turbine (CT), internal combustion, or steam units. These units have a wide range of prices as observed on the left-hand side of the price duration curve.

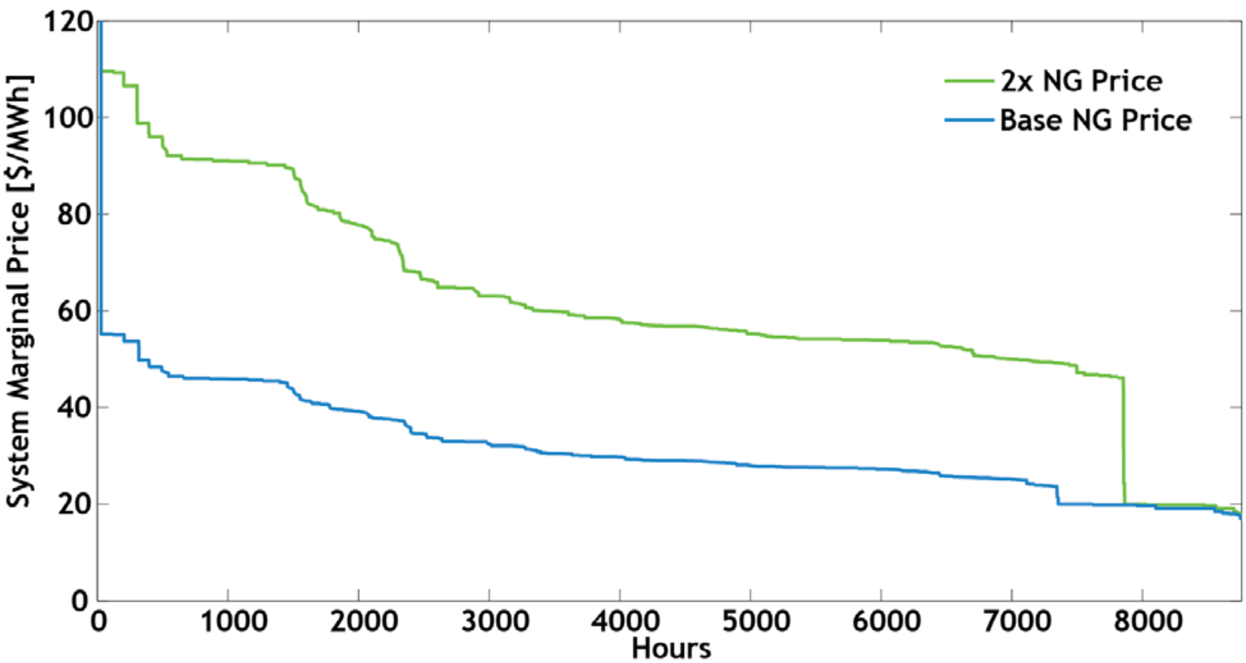

Figure 2. Price duration curves for the lowest VG (16%) case[18]

[17] While storage can theoretically charge with wind and solar at any time, it incurs an opportunity cost to do so. When VG is added to a power system, the marginal (highest cost) source of generation reduces output to accommodate the natural inflow of wind or solar. If the VG is instead used to charge storage, it does not provide the benefit of avoiding the marginal source of generation during the time of its natural generation. Instead, it is then dispatched later at a period when (ideally) a higher cost generator is at the margin. However, this incurs a loss in storage and this loss represents the significant tradeoff associated with charging storage with VG sources. Said differently, when VG is added to the power system it can either sell energy at the current (marginal) price or it can charge storage. When VG charges storage it gives up the opportunity to sell energy at the current marginal price which represents the opportunity cost. We refer to "zero opportunity cost" VG as generation that occurs when VG would otherwise be curtailed or have zero value to the system. During these periods, there is no lost opportunity associated with charging storage with wind and solar.

[18] Figure 2 demonstrates a shift in right side of the price duration curve for the high natural gas price case, with fewer hours of coal on the margin. This phenomenon is due to the presences of existing pumped storage assets. The

As VG is added, it displaces a mix of generation types, changing price patterns and the opportunities for energy arbitrage. Figure 3 shows the impact on net load and price during a three-day period starting on July 29, during the period of annual peak demand. The price curves (Figure 3b) show a reduction in off-peak prices. This is most clearly observed in the overnight hours between day one and two. In the 16% VG case, the net load drops to the point where highly efficient combined cycle units (about $28/MWh) set the marginal price. However, the addition of VG reduces demand to the point where lower-cost coal units (about $20/MWh) are on the margin. This creates opportunities for storage to charge with lower-cost coal generation. There is also a reduction in on-peak prices, largely on the first day in the highest VG scenario, where net demand is reduced to the point where combined-cycle units replace the more expensive combustion turbines for meeting peak demand.

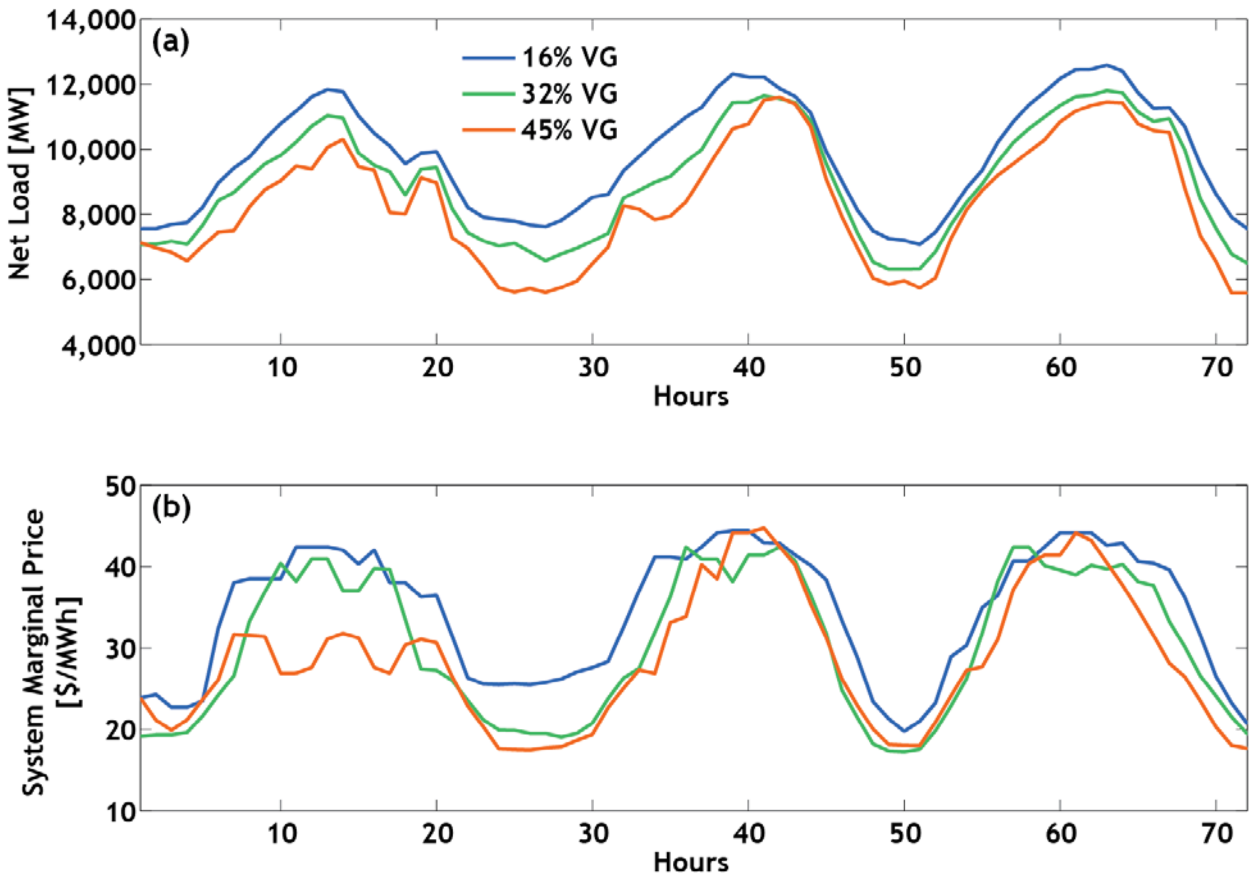

Figure 3a (top). Net load for VG penetrations of 16%, 32%, and 45% during three summer days beginning July 29; Figure 3b (bottom). System marginal price for same periods[19]

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increase in natural gas prices results in more incentive for pumped storage operation. In the high gas price case, there is a greater difference between coal and gas generators resulting in the pumped storage plant charging more during hours when coal generation is available. This actually reduces the amount of time when coal is at the margin, and results in gas being the marginal fuel (and setting the marginal price) more often. This impact is a specific case of the more general impacts of storage on prices, discussed in more detail in Section 4.4.

[19] The price data in these figures has been smoothed by applying a two-period moving average. This is done to clarify the images, however did not affect the actual analysis. Marginal price data for relatively small systems is often irregular as start-up requirements from hour to hour, and other changes create large jumps between units. This

Figure 4 shows the same data for a period beginning on April 5. This period has both lower load and much more wind, creating a more complicated relationship between loads and prices. In the two higher penetration scenarios, wind and solar generation in the middle of the first day exceeds what can be accommodated by the flexibility of the system. As a result, wind is curtailed and the price of energy drops to zero. This also occurs in the overnight hours between days two and three. During other periods, the marginal price is influenced greatly by the ramp rates required by the system net load, often requiring use of fast-ramping combustion turbines, which may need to be started for short intervals.

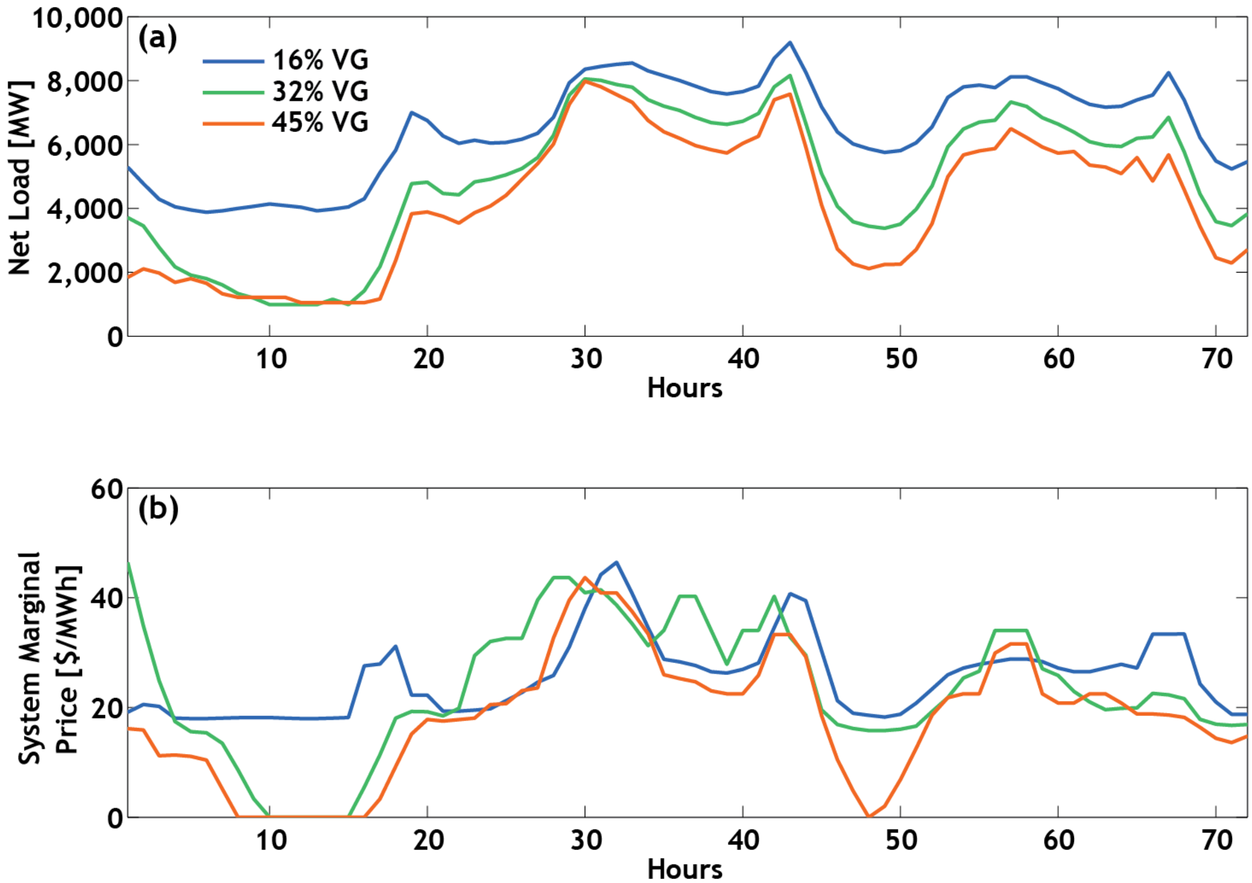

Figure 4a (top). Net load for VG penetrations of 16%, 32%, and 45% during three spring days beginning April 5; Figure 4b (bottom). System marginal price for same periods

The effect of VG on system prices can be observed in aggregate in the price duration curves for these three penetrations, provided in Figure 5. They demonstrate the increased availability of low-priced charging energy, mainly as wind and solar frees up coal capacity, observed by the increased number of hours where the marginal price is about $20/MWh. In the 32% penetration case, coal capacity becomes available during about 50% of the hours, while the 45% case introduces about 600 hours of zero-priced energy due to the flexibility limits of the system. As

phenomenon can be observed in system marginal price (lambda) data from vertically integrated utilities reporting this data to the Federal Energy Regulatory Commission on Form 714.

discussed later in this section, this presents significant opportunities for energy storage to charge with zero-fuel-cost energy.

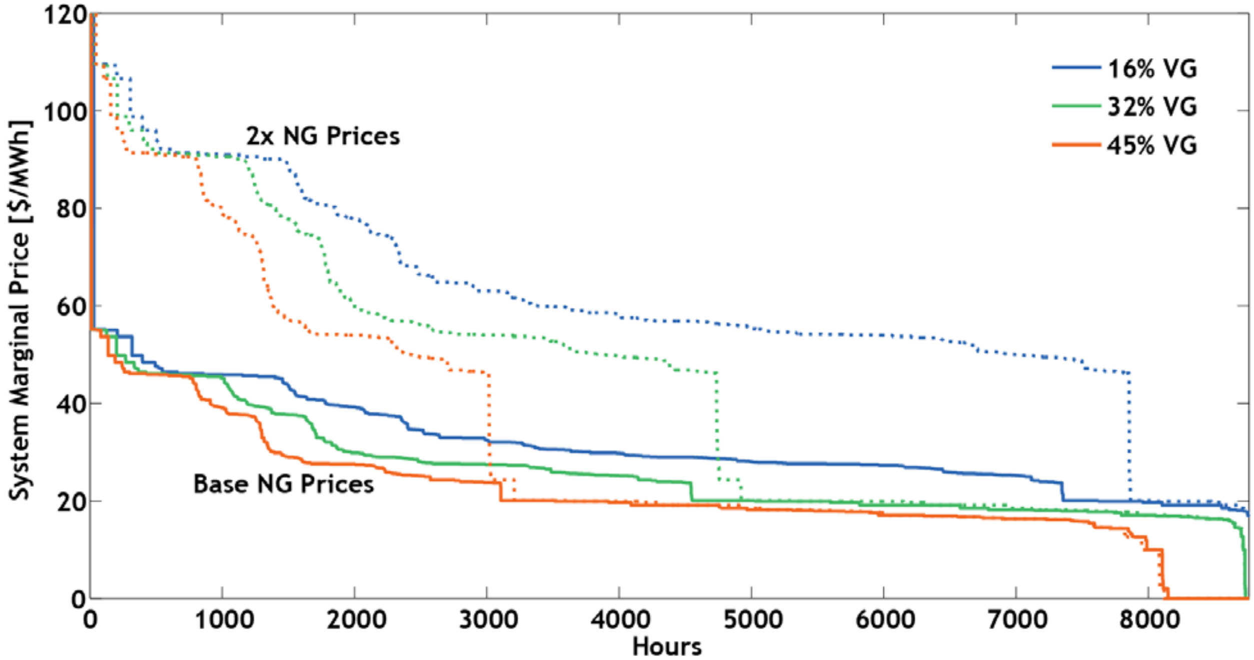

Figure 5. Price duration curves for VG penetrations of 16%, 32%, and 45%.

The net effect of wind and solar is to reduce the cost of off-peak charging by a greater amount than the value of discharge during on-peak periods. This can be observed by calculating the effective charging costs and discharge revenue of the energy storage device in each scenario. Figure 6 demonstrates this explicitly. It calculates the effective "revenue" of the storage device if it were in a market setting. It uses the hourly marginal prices and the charge patterns calculated by the PLEXOS model. In each hour, the revenue or cost is calculated by multiplying the amount of charging/discharging by the marginal price. This can be used to indicate the general trends in charging or discharging value. As VG penetration increases, there is generally a decrease in energy revenue for energy storage as there are fewer hours of high price energy. This can be observed on both the price duration curves. However, there is a greater reduction in the cost of charging, which produces an overall increase in net revenue.

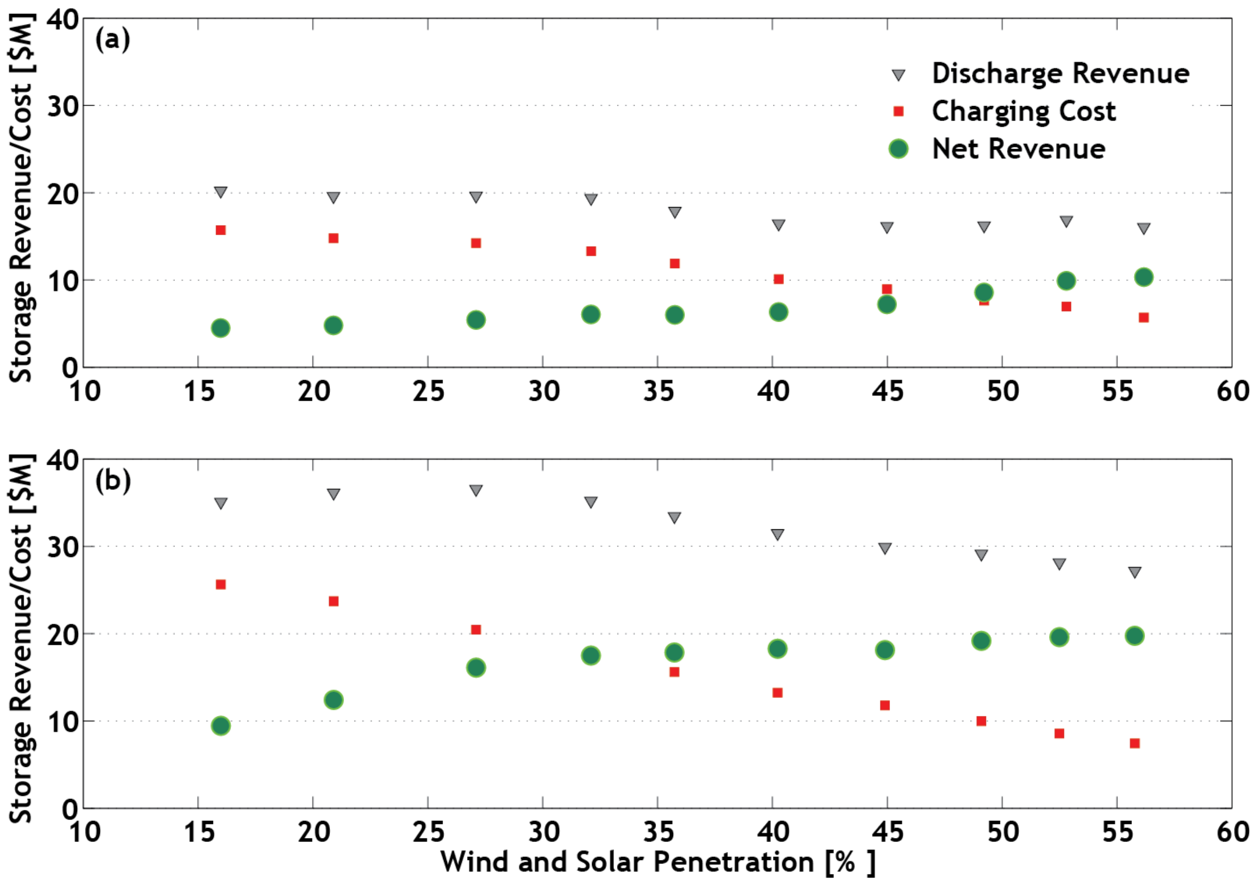

Figure 6. Annual revenue for a 300 MW energy-only device in the analyzed system: (a) Base system; (b) System with doubled natural gas prices

Figure 6 should be used only as a general indication of why the value of storage increases as a function of penetration. It is a simplification of the actual storage plant operation and the sources of system benefits. In reality, because of relatively small arbitrage opportunities, the dispatch model often chooses to use the storage device to avoid power plant starts, at the expense of the smaller arbitrage opportunities. The value avoided power plant starts is not reflected in Figure 6,[20] and this leads to broader issues associated with storage plants in market settings, including uncaptured benefits, and the challenge of deciding which party should actually schedule energy storage to maximize its benefit to the system as a whole (Denholm et al. 2013; Sioshansi et al. 2012). These issues are discussed in greater detail in Section 4.4. Figure 7 shows the actual source of system value based on the storage plant operation simulated in the model. At low VG penetration, the model finds greater opportunities for savings associated with power plant starts. As the on-/off-peak price differential increases (mainly as a result of reduced off-peak prices), the model finds greater opportunities to use the device for load-leveling, demonstrated by the increase in fuel savings. (Only the base natural gas price is shown, but the trend is similar for the doubled natural gas price scenario.)

[20] For additional discussion of capturing start costs in energy prices and proposed market mechanisms to address this issue see "Extended Locational Marginal Pricing" https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/ELMP%20FAQs.pdf

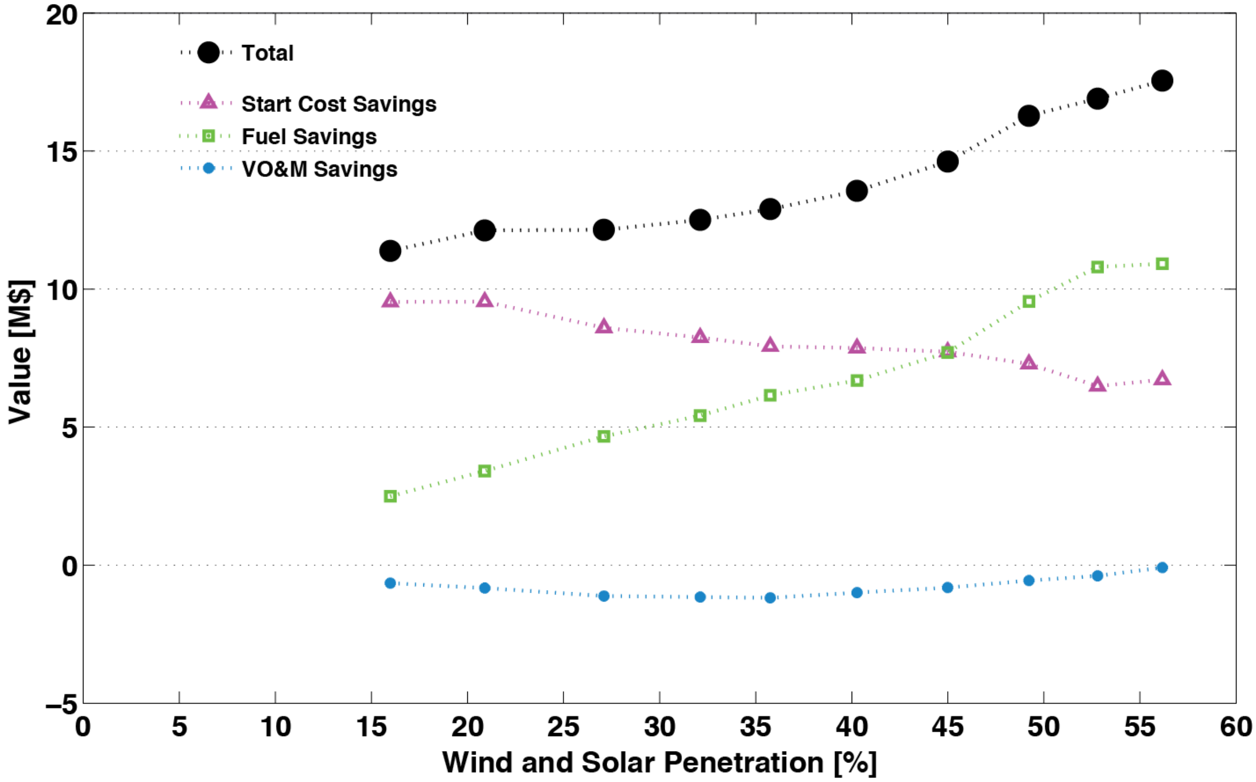

Figure 7. Origin of storage value as a function of VG penetration for the base system

The hourly price curves in Figure 4 and price duration curves in Figure 5 point to the potential opportunities to use zero generation cost and zero carbon renewable energy to displace fossil generation using storage. However, these opportunities do not appear to be significant until very high penetration of renewable energy (similar to results found by Tuohy and O'Malley 2011). In the 45% VG case, the price of energy is zero for about 600–650 hours. During these periods, renewable energy is curtailed, and storage has the opportunity to charge with zero-cost VG.[21] The amount of curtailment increases dramatically as the penetration of VG increases. Figure 8 shows curtailment rates of VG sources that occur in the scenarios without storage. The total curtailment curve is calculated by dividing the total curtailment by the total potential renewable generation. The marginal (or incremental) curtailment represents the additional curtailment between one scenario and the next, divided by the incremental VG from one scenario to the next.[22]

The relatively low curtailment rates in Figure 8 point to several of the challenges of modeling the current and future grid. The model assumes a least-cost dispatch across the modeled region, and does not include a number of institution limits to system flexibility. Specifically, the model does not consider the large number of bilateral contracts, operator experience, and other non-technical constraints on individual plants to be ramped or cycled. Furthermore the model uses technical parameters (derived from the TEPPC database) that may be aggressive, such as the assumption

[21] In regions with restructured markets, curtailed wind energy can often result in negative market clearing prices due to the presence of the production tax credit.

[22] A more extensive discussion of incremental curtailment rates is provided by Denholm and Hand (2011).

that all coal units can be cycled down to 40% of rating without any impact on costs other than the effect of part-load heat rates. In addition, the analysis does not consider additional technical challenges associated with meeting a very high fraction of demand from renewables. In the highest VG penetration scenario, during some hours the entire energy demand and reserve requirements are met by renewable sources; this level of penetration has yet to be evaluated in detail and it is unclear if inertia or other requirements will preclude this level of instantaneous penetration of VG. Including additional operational constraints would increase curtailments and generally increase the value of energy storage at lower levels of VG penetration.

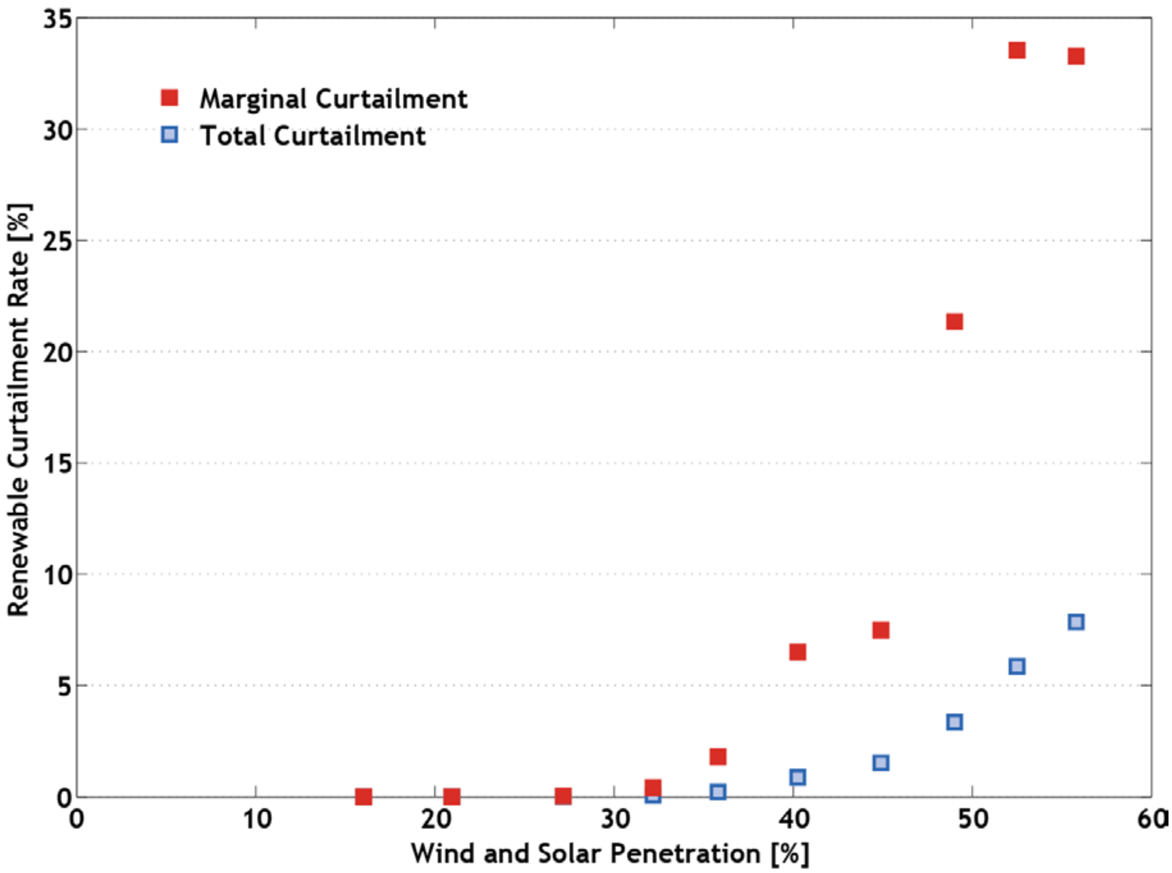

Figure 8. Marginal and total curtailment as a function of VG penetration[23]

While marginal curtailment rates become quite high (about one-third of the additional renewable energy required to get from 49% to 53% is rejected due to system flexibility constraints and supply/demand mismatch), it does not become significant until the system achieves about 40% annual energy from VG. As a result of this, significant charging from curtailed VG does not occur until penetration levels are relatively high. Figure 9 shows the fraction of charging that occurs from VG, as measured by the reduction in curtailment that occurs when adding storage. (In reality, there is no way to determine the precise source of charging energy that occurs in an optimally dispatched power system, but reduction in curtailment is a direct result of adding storage so can be attributed to storage.)

[23]The discontinuity in the figure is largely due to the use of discrete plants with different temporal patterns that can increase and decrease correlation with demand patterns as a function of penetration.

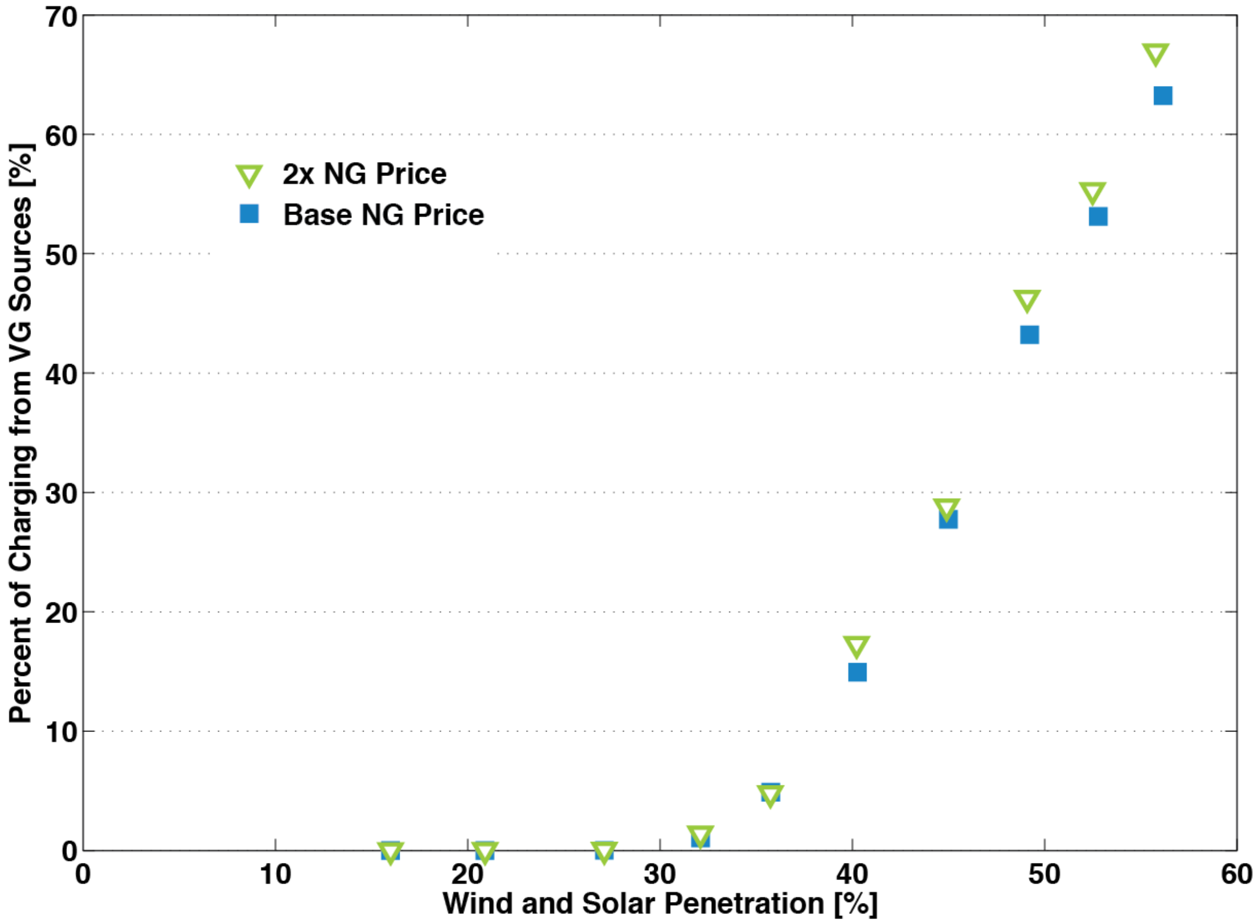

Figure 9. Fraction of total charging occurs from otherwise curtailed renewable energy

Figure 9 provides an indication that energy storage can help effectively integrate VG, particularly at very high penetration. While this analysis is not intended to evaluate technical barriers to VG integration, it demonstrates the economic challenge of renewable integration and how storage can act as an enabling technology. Specifically, the increasing curtailment rates that occur beyond 35% to 40% penetration provide a significant disincentive for additional contribution from VG. Depending on the allocation of curtailment, the effective cost of VG increases as its capacity factor drops due to unusable generation. Energy storage can charge with otherwise unusable renewable energy and decrease curtailment. As an example, in the case where VG penetration increases from 44% to 49%, a total of 1,455 MW of VG is added, with a potential generation of 4,002 GWh. Of this additional generation, about 855 GWh, or about 21%, is curtailed. At the average capacity factor of this resource (35% for wind, 20% for solar), this implies about 297 “average” MW of wind and solar cannot be utilized by the grid. The addition of 300 MW of energy storage reduces this curtailment by 278 GWh, or about 96 MW of average wind or solar. As a result, in this scenario the addition of 300 MW of storage effectively enables an additional 96 MW of wind and solar, in addition to providing other benefits of reduced starts and fuel cost savings. There are several important points about this conclusion. First, this represents only an example and should not be interpreted as a general rule that a certain amount of storage enables a specific amount of VG. The size of the storage device simulated (300 MW with 8 hours of discharge capacity) was not optimized in any way and further analysis would be needed to determine the best configuration for overall grid benefits, which would include reducing VG curtailment. Furthermore, even in this example, less than half the charging energy is effectively being derived from wind and solar. The majority of the charging is still being derived from fossil sources used to optimize the overall system performance. This indicates that "coupling" specific renewable generators to storage is generally non-optimal and will result in an underutilized storage asset.

As a result of fossil charging, and no assumptions regarding carbon constraints or costs, the addition of an energy-only storage increases carbon dioxide (CO_2) emissions in this test system until VG penetration reached about 50%.[24] Beyond this point renewable charging produces a net decrease in CO_2 emissions due to the addition of energy storage. Figure 10 indicates the increase in carbon emissions associated with the addition of the 300 MW storage device. Two curves are shown, with the upper curve representing only the impact of operational fuel, and the lower curve considering the additional emissions savings of avoided starts. The emissions impacts of avoided starts were estimated based on the average start fuel requirements for power plants of different types.[25]

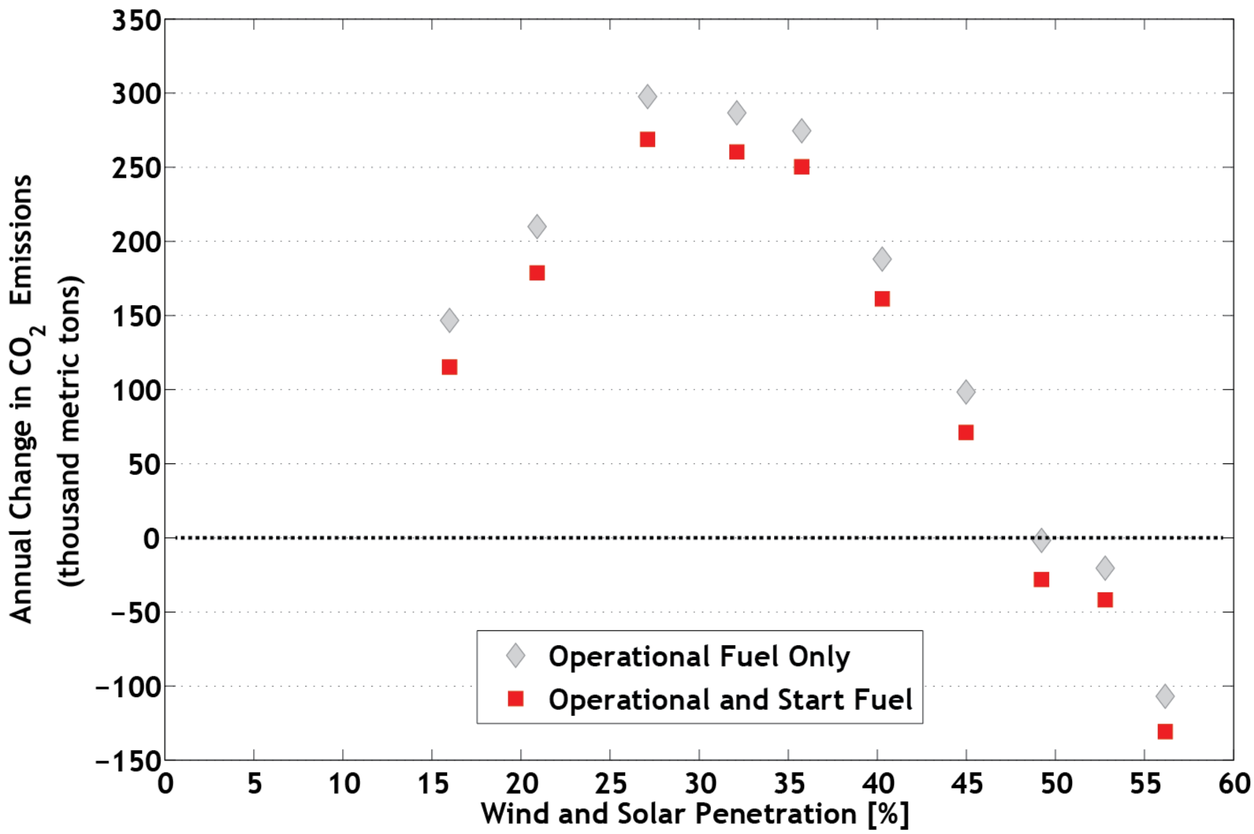

Figure 10. Carbon emissions associated with adding a 300 MW energy-only storage plant

[24] This result is similar to an analysis of storage on the Irish system, which found the addition of storage produced an increase in carbon emissions until the contribution of wind was greater than 60% on an energy basis (Tuohy and O'Malley 2011).
[25] These values were calculated outside the optimization model using data for start fuel requirements from Table 2 of the Western Wind and Solar Integration Study Phase 2 (Lew et al. 2013). For calculation of associated emissions, we assume that the average start fuel across all plant types is 50% oil and 50% natural gas, with a resulting carbon content of 139 lb/MMBtu. http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

4.2 Impact of Coal Retirements

The base scenario is unrealistic given the large growth in generation capacity without any retirements. Wind and PV both provide additional capacity to the system, although their capacity credit (the fraction of their nameplate capacity that can be expected to reliably serve load) is generally less than conventional generators. Regardless of the actual capacity credit, the scenarios result in increasingly "overbuilt" systems with excess capacity. Furthermore, the extremely high renewable scenarios would likely be the consequence of carbon constraints or other policies that would tend to reduce installed coal capacity. Finally, the high penetration scenarios would likely occur much further in the future than 2020, leading to the natural retirement of older coal-fired plants due to age. These retirements would also be motivated by decreasing capacity factors leading to lower overall economic performance. Without retirements, the fleet average capacity factors for coal plants falls from 85% in the lowest (16%) VG scenario, to about 52% in the 55% VG case. In this high renewable energy case, several of the coal units have annual capacity factors below 45%.

As a result, we created a scenario in which we retired coal plants in each successive scenario. In each VG penetration scenario, we identified plants whose capacity factor fell by at least 5% after the addition of renewable sources and removed them from that scenario. This scenario is not an attempt to establish a general relationship, or to optimize the mix of generators providing load, but is merely an example analysis of how one specific generation mix associated with coal retirements might affect the value of storage. Reserve requirements were not altered.[26] We then re-ran the scenario with and without energy storage.

Figure 11 illustrates the impact of coal retirements on the generation mix. It shows that in the case without coal retirements, natural gas generation is largely eliminated from the system at the highest VG penetration, leaving a largely coal/renewable generation mix. In the case with coal retirements, the system remains somewhat more balanced, with a greater contribution from gas-fired generation.

[26] We never retired the single-largest unit (a super-critical coal plant) as that is the newest and most efficient coal-fired unit in the simulated system. Retirement of that unit would have lowered the contingency reserves requirement.

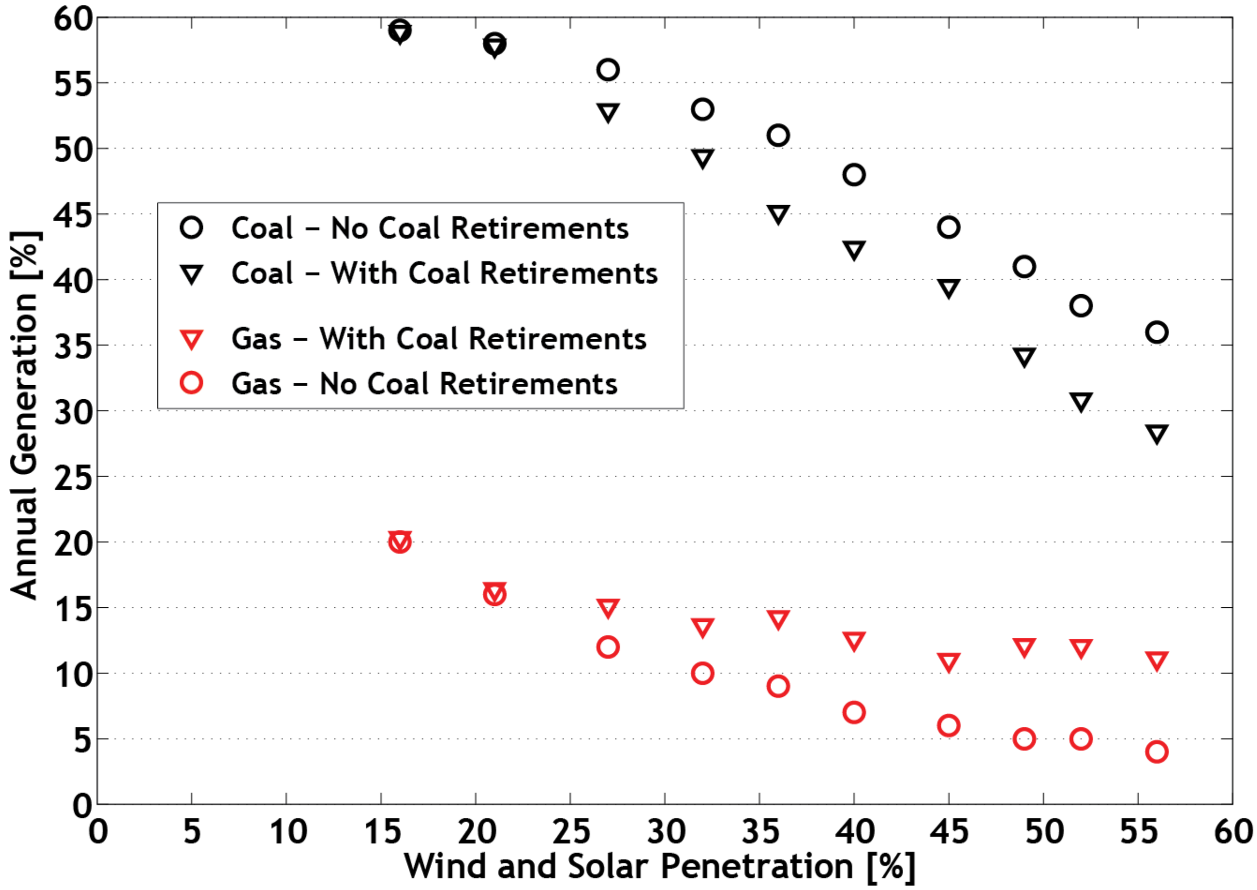

Figure 11. Generation mix for the various scenarios in the base case and with coal retirements

Figure 12 shows the results of the coal retirement scenarios compared to the base scenario with no coal retirements.

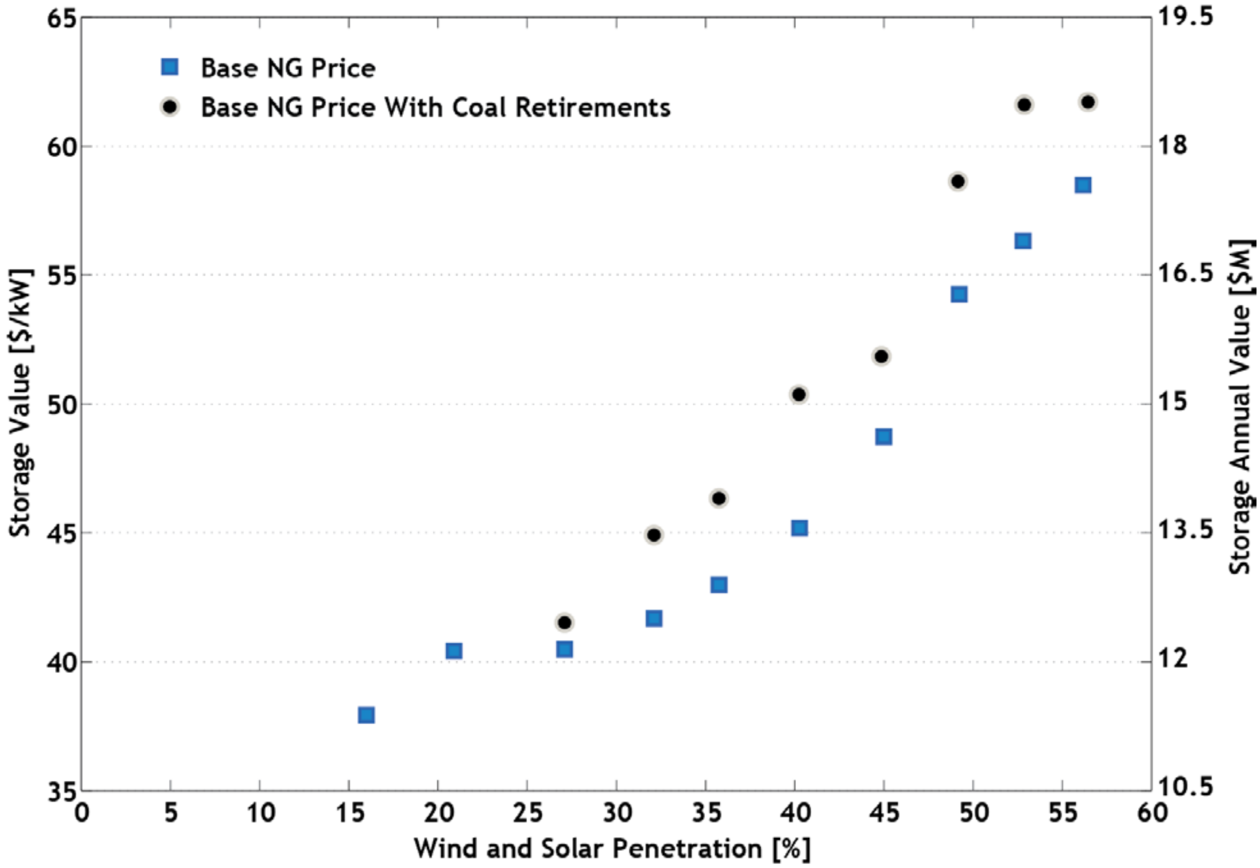

Figure 12. Annual value of the base 300 MW energy-only storage device and in a case with increasing coal retirements

Further explanation of the modest impact of the coal retirement scenario is provided in Figure 13, which is calculated in the same manner as Figure 6. Reducing coal capacity reduces the opportunity for low-cost charging from coal. Reducing coal also increases system flexibility, which reduces wind and solar curtailment. This reduces the opportunity for storage to use otherwise zero-fuel-cost wind and solar for charging compared to the base system, as demonstrated in Figure 14. Combined, these factors mean the charging costs do not drop as rapidly with retirements as they do in the base case. However removing coal allows gas to stay on the margin during more hours. This increases the discharge revenue, which remains fairly constant as a function of VG penetration, and more than makes up for the increase in charging costs.

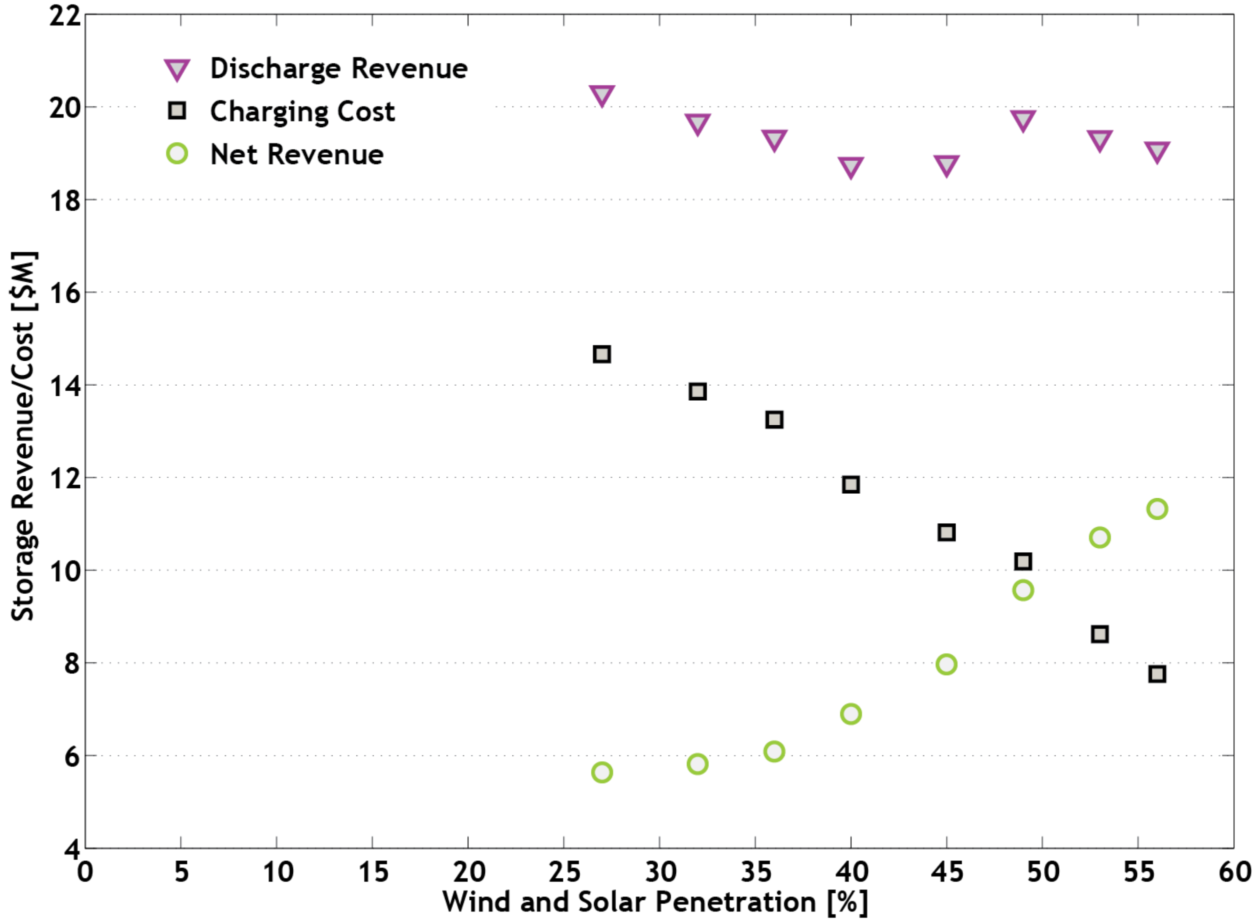

Figure 13. Annual revenue for a 300 MW energy-only device in the system with coal retirements

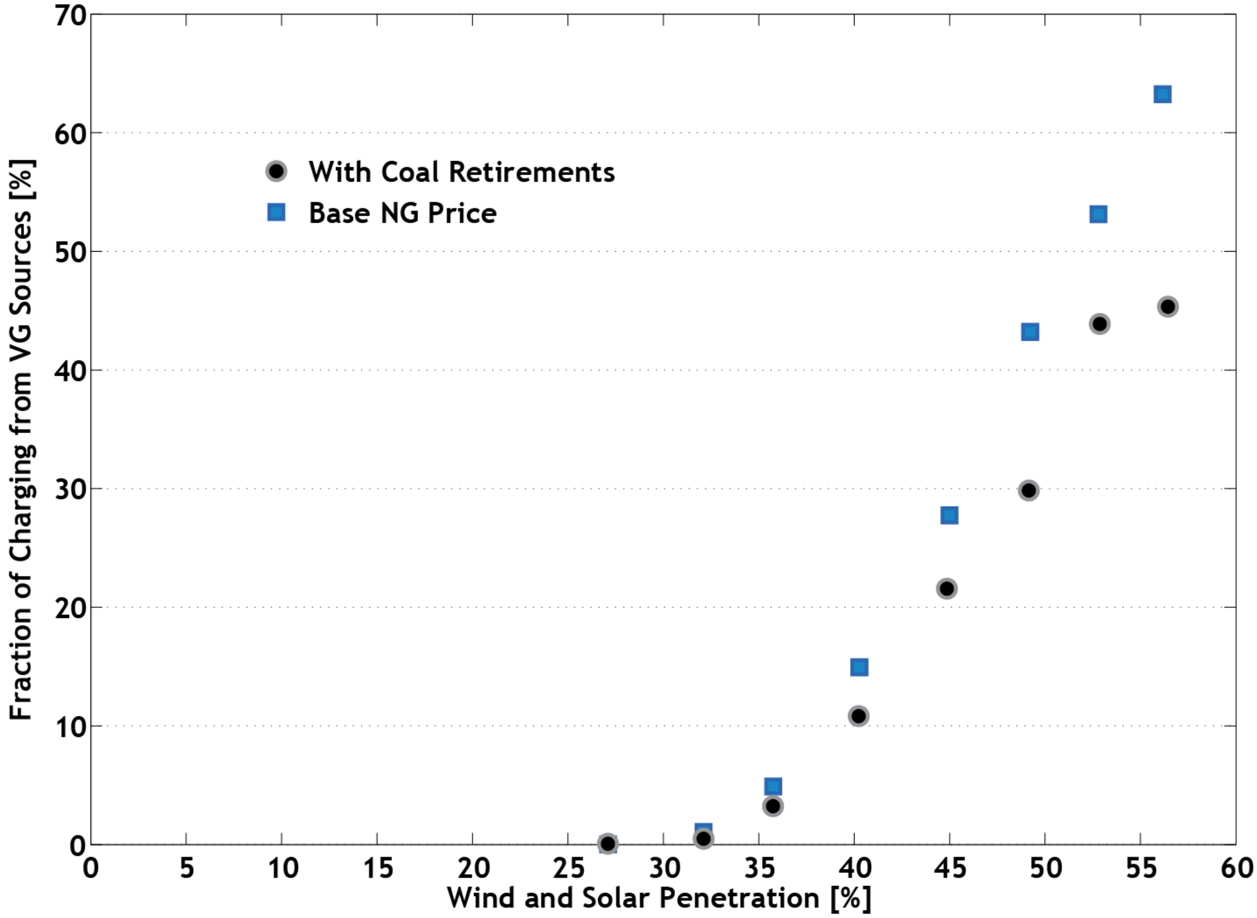

Figure 14. Fraction of total charging that occurs from otherwise curtailed renewable energy

4.3 Reserves-Only and Co-Optimized Storage Devices

We simulated two types of devices able to provide operating reserves to the system. A 100 MW device was allowed to provide both regulation and contingency reserves. In addition, we evaluated a 300 MW device (the same size as the energy-only device) able to provide both energy and regulation or contingency reserves while discharging. In addition, this device was allowed to provide contingency reserves (but not regulation) while charging.

Figure 15 provides the value results for the energy-only device from Section 4.1, plus the two devices capable of providing reserves. (Because of the fairly continuous trends observed in the energy-only device cases, we only evaluated reserves scenarios in 10% increments of VG penetration.)

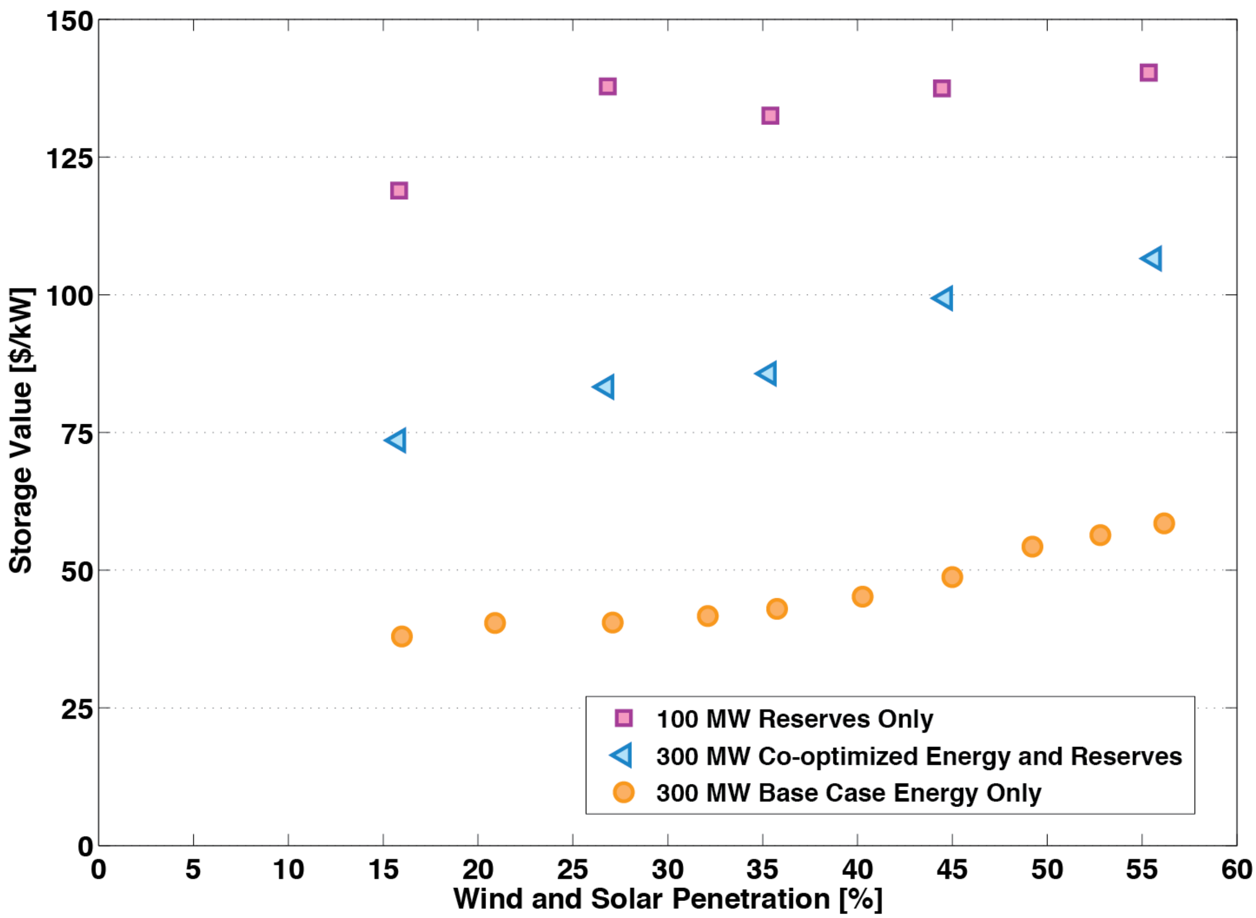

Figure 15. Annual value of the energy-only, reserves-only, and energy-plus reserves devices as a function of VG penetration (value measured on a per unit of capacity basis)

Figure 15 shows the impact of both the difference in value between energy and reserves services as well as the significant impact of device size. The reserves-only device has the highest value on a per unit of capacity basis, following previous analysis of the relative value of various services that can be provided by energy storage. In theory a co-optimized device should have a higher value than the reserves-only device. However the 300 MW co-optimized device shows a lower value than the smaller reserves-only device, demonstrating the limited size of the highest value reserves requirements. In the lowest VG case, the 100 MW reserves-only device uses about 98% of its available capacity on average to provide regulation, which provides about 82% of the total requirement for regulation reserves (because the regulation reserve requirement is about 120 MW on average).[27]

The size of the co-optimized device (at 300 MW) greatly exceeds the regulation requirement in the simulated system. Because regulation is a high value service, the 300 MW co-optimized device serves most of the requirement "first" and uses what is left over for a combination of contingency reserves and load-leveling. Because a device providing reserves requires less energy than a device providing both energy and reserves, it might be more economical to deploy dedicated reserves devices targeted toward the amount of reserves actually needed by the system

[27] For reliability reasons, reserves may be required to be shared across multiple generators.

if those devices become cost-effective. It should be noted that the results in this section do not include additional value provided new markets for fast response storage devices.[28] Additional analysis is needed of the potential benefits of sub-hourly storage dispatch, along with more detailed analysis of storage providing separate up and down reserves when co-optimized with overall system operation. The operation of the devices capable of providing reserves also changes its impact on carbon emissions relative to the energy-only device. Figure 17 shows the change in CO_2 associated with the reserves-only and co-optimized device compared to the energy-only device shown previously in Figure 10. Given the limitations inherent in modeling provision of regulation reserves in an hourly model, and the challenges of estimating emissions associated with part-load operation (Atanacio et al. 2012), these values should be interpreted as trends in avoided emissions in the simulated system with considerable uncertainty in the absolute values.

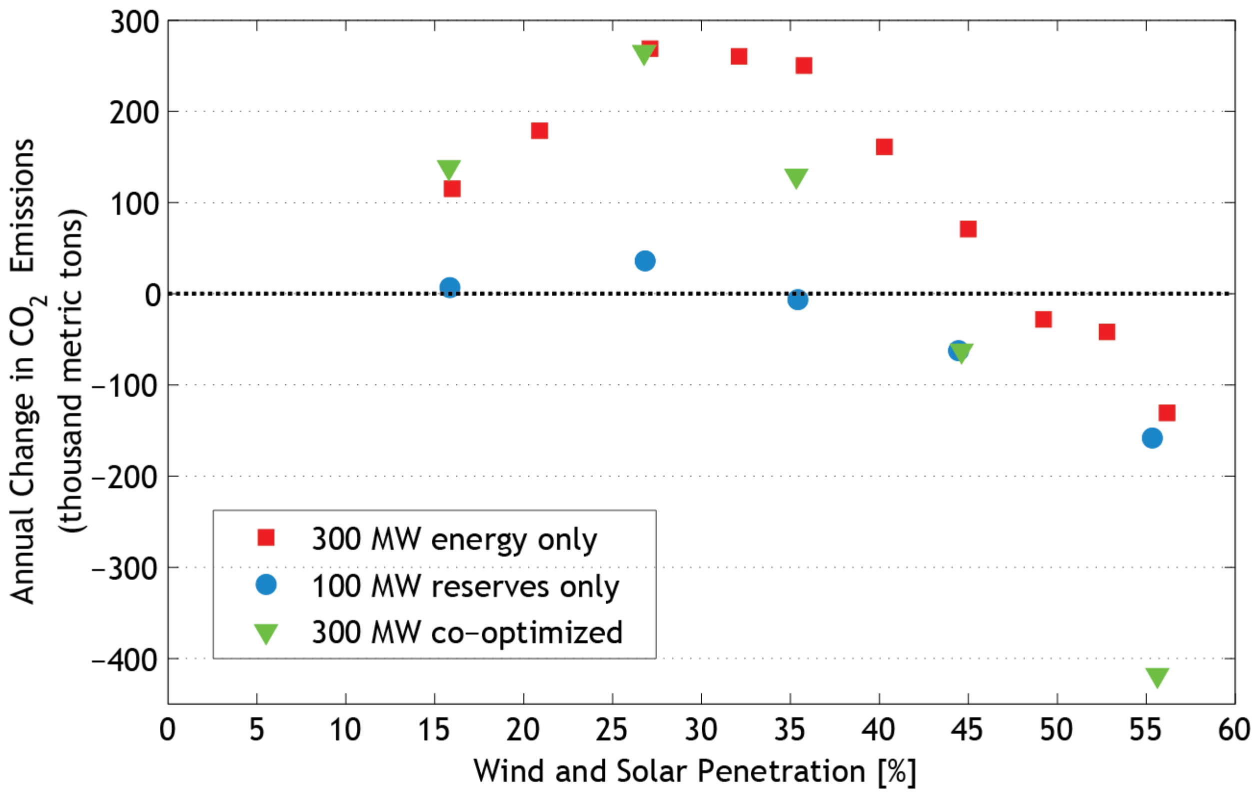

Figure 16. Carbon emissions associated with adding the energy-only, reserves-only, and energy-plus reserves devices as a function of VG penetration

4.4 Value and Revenue

The results presented in the previous sections demonstrate the operational value of the storage device by comparing the difference in production cost. A challenge of energy storage deployment, particularly in regions with restructured markets is monetizing and capturing this

[28] The new markets have been created in response to FERC order 755, which states "This Final Rule requires RTOs and ISOs to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal" (FERC 2011).

value. Our previous study demonstrated there is potentially a significant difference between our calculated value and the potential revenue capture in wholesale energy markets driven by a variety of factors such as inability to capture value associated with plant starts[29] (Denholm et al. 2013).

A challenge faced by all low-variable cost generators is their impact on prices; however storage may be particularly impacted because it tends to influence prices during both charging (where it acts to increase its own costs) as well as discharging (where it acts to decrease its revenue). This can substantially reduce or, in the extreme case, eliminate storage revenues, even while continuing to provide a direct benefit to the system and consumers. Figure 17 illustrates the potential impact of storage on marginal prices in a VG scenario. (This is a conceptual and extreme scenario used to illustrate this issue). Price zones include coal at $20/MWh, CCGT generation at $37.5/MWh and CT generation at $50/MWh. In addition, renewable energy is curtailed during several overnight hours due to low net load. This is demonstrated by zero energy prices during the hours between 1 a.m. and 4 a.m. An added storage plant could charge with zero-fuel-cost renewable energy and provide significant benefits reducing or eliminating the use of the peaking CT in the late afternoon. In this example, a 300 MW storage plant could displace $45,000 of operational costs (300 MW * 3 hours * $50/MWh) by charging with renewables and displacing the peaking capacity. However, if that 300 MW was sufficient to absorb all the curtailed wind and exactly displace generation from the peaking unit, the "price with storage" curve demonstrates the resulting marginal prices. The storage plant when charging has increased the load to the point where fossil (coal) generation is now on the margin. As a result, the marginal price is no longer zero, but $20/MWh, so in a market setting, charging energy consumed by energy storage would cost $20/MWh, as opposed to $0/MWh, even if the storage plant charges mostly (or entirely) from renewable energy. During peak periods, the opposite occurs. The storage plant displaces the high cost CT, reducing prices to $37.5/MWh (the price of generation from the CCGT). Under these circumstances, the storage plant with a 75% round-trip efficiency would pay $24,000 for charging energy (300 MW * 4 hours *$20/MWh) and receive $33,750 in revenue (300 MW * 3 hours * $37.5/MWh) for a net revenue of $9,750, while still providing $45,000 in reduced operating costs to the system. In an extreme case, a storage plant could change the net load to the point where on- and off-peak prices are the same, and while the storage plant could provide significant value it could actually lose money in a market setting. The same general phenomenon could also occur for a storage device providing reserves.

[29] Proposed market designs such as MISO's "Extended Locational Marginal Pricing" would include the costs of unit starts in marginal energy prices. https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/ELMP%20FAQs.pdf

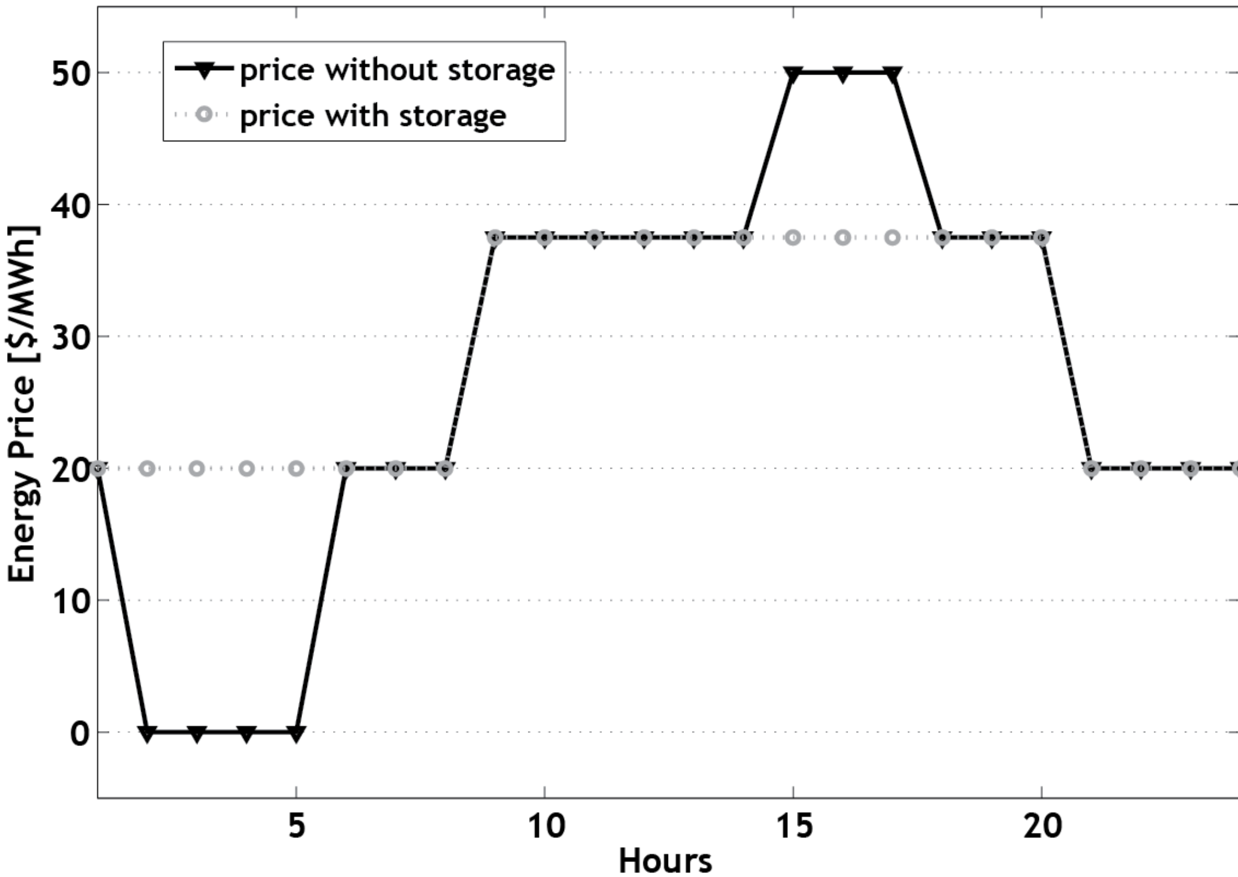

Figure 17. Conceptual illustration of how storage suppresses on-/off-peak prices in a high VG scenario and reduces revenue compared to the value it provides

Figure 18 shows the fraction of the total value actually captured by the storage device based on market revenues in the simulated scenarios.[30] There are several trends noticeable in Figure 18. For the energy-only device, the increase in captured value, particularly for the low fuel cost case is due to the increased arbitrage opportunities that occur at higher VG penetration. This decreases the fraction of the value that needs to be obtained from starts, which increases the overall "capturable" value via price arbitrage.

[30] This implicitly assumes that the marginal prices generated by a production cost model are equal to the marginal prices generated in a market setting. This is an important and potentially significant limitation when comparing the value of storage in a vertically integrated utility and a restructured market. Production cost models typically do not include generator bidding and other factors that could drive market prices much higher. The results presented here are unlikely to represent the true difference between storage value in a market and non-market setting. However, they do represent some of the general challenges associated with value capture by energy storage associated with generator starts and price suppression. Additional analysis is needed to evaluate the actual difference between value and revenue capture, as well as the sensitivity of revenue capture to storage type, fuel prices and generator mix.

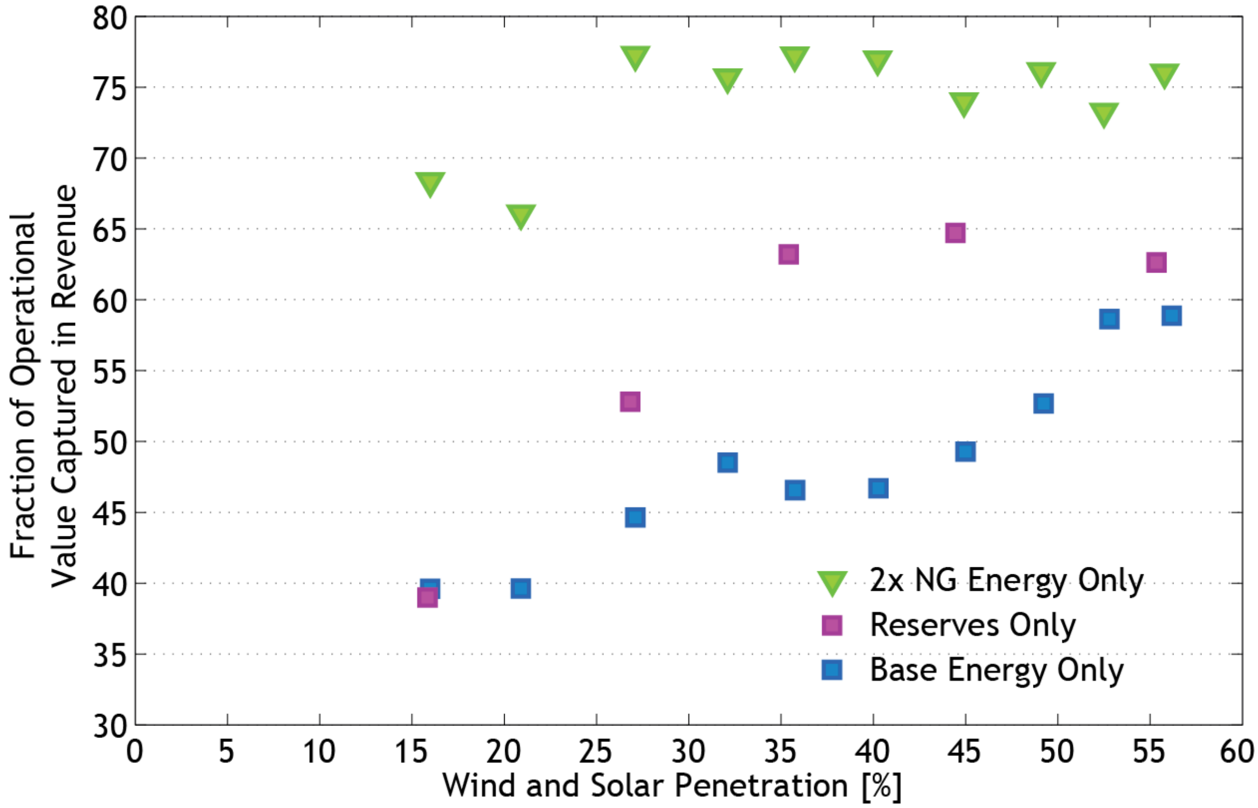

Figure 18. Fraction of operational value captured by market revenues for various scenarios

For the reserves-only device, the fraction of value captured by revenue payments increases as a function of VG penetration. This is largely due to the increased size of the regulation requirement, which reduces the price suppression effects of energy storage (the 100 MW device does not completely saturate the regulation requirements). This is demonstrated in Figure 19, which shows the average price of regulation for cases with and without storage. In the lowest VG case, the addition of 100 MW of storage reduces average prices by about 60%, while this impact drops substantially as the increase of VG increases the overall market size of VG. The decrease in regulation prices at the highest penetration case in Figure 19 is due to the provision of zero-cost reserves from curtailed VG.[31]

[31] This issue is discussed at length by Hummon et al. (2013).

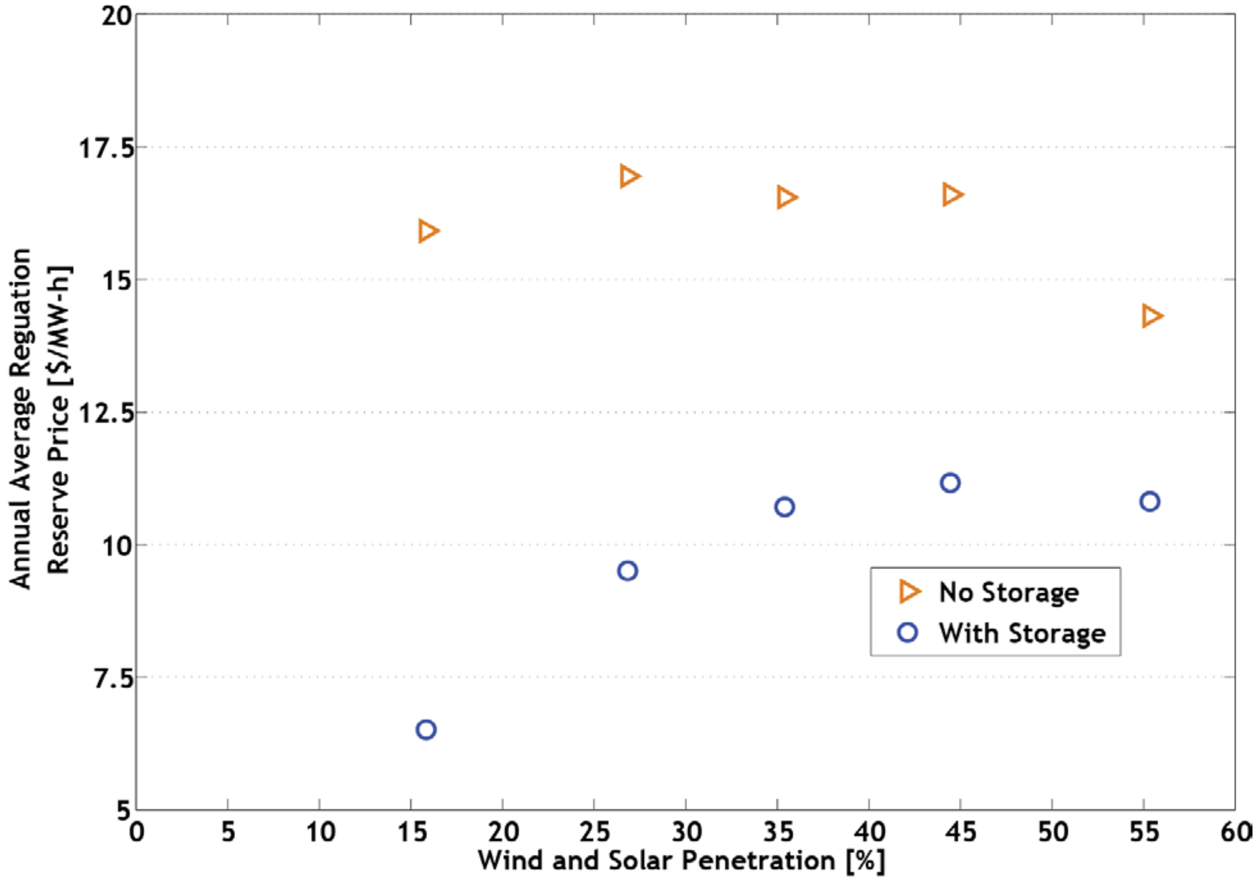

Figure 19. Impact of energy storage on average regulation reserves price[32]

[32] The unit "MW-h" on the y-axis of Figure 18 is sometimes applied to capacity-related services such as operating reserves. It represents a unit of capacity (MW) held for one hour. It is distinct from MWh which is a unit of energy.

5 Conclusions and Future Work

The introduction of increased amounts of renewable energy appears to increase the economic opportunities for energy storage. This is driven by a number of quantifiable factors. For applications involving time-shifting of generation (otherwise known as load-leveling or energy arbitrage), the mixes of wind and PV evaluated tend to suppress off-peak prices more than on-peak prices, increasing price differentials for energy storage. The addition of renewables also increases the overall requirement for operating reserves, which may increase the market opportunities for storage devices providing these reserves.

Overall there is also a potential synergistic relationship between renewables and energy storage. In the high penetration scenarios evaluated in this work, there was considerable curtailment of wind and solar generation in systems without added storage. Developers would be unlikely to deploy renewable energy with excessive curtailment. Storage can demonstrably reduce curtailment, potentially increasing the value of renewables, particularly at high levels of deployment.

Overall, the increased value of storage demonstrated in this work is potentially limited by the compensation mechanisms that exist in restructured markets. If storage is unable to take advantage of its total system value, including its ability to reduce operational costs and capacity-related benefits, the low revenues it will obtain will likely be unable to support the capital costs of most current storage technologies.

Further analysis is needed to increase understanding of the potential value and opportunities for energy storage in an evolving grid under current and alternative market rules. Because operating reserves (particularly regulation reserves) appears to be a significant opportunity, further analysis of actual reserves provision from storage is required. This includes higher time resolution simulation and more detailed treatment of reserve provision including energy constraints. Additional analysis is also needed on different generation mixes, and the potential competition from alternative sources of grid flexibility such as demand response. Finally, analysis is required to understand the additional values provided by distributed storage and how distributed storage can effectively be integrated into the bulk power system.

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