The Value of Energy Storage for Grid Applications

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Forward

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 Office of Energy Efficiency and Renewable Energy and the 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 like wind and solar power 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/.

Abstract

Electricity storage technologies have had limited deployment in the U.S. power grid, despite the multiple benefits they can provide. One of the challenges faced by storage developers is quantifying their value, especially considering benefits that may not be fully captured within U.S. electricity markets.

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. Storage devices were added to a utility system in the western United States, and the operational cost of generation was compared to the same system without the added storage. This operational value of storage was estimated for devices of various sizes, providing different services, and with several sensitivities to fuel price and other factors. Overall, the results followed previous analyses that demonstrate relatively low value for load-leveling but greater value for provision of reserve services. The value calculated by taking the difference in operational costs between cases with and without energy storage represents the operational cost savings from deploying storage by a traditional vertically integrated utility. In addition, we estimated the potential revenues derived from a merchant storage plant in a restructured market, based on marginal system prices. Due to suppression of on-/off-peak price differentials and incomplete capture of 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 provided to the system. This demonstrates some of the additional challenges for storage deployed in restructured energy markets.

Further analysis is required to estimate the impact of renewable penetration and generation mix on storage value. 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.

Table of Contents

List of Figures

List of Tables

1 Introduction

Electricity storage can provide multiple benefits to the grid, including the ability to levelize load, provide ancillary services, and provide firm capacity. Historically, it has been difficult to compare the value of electricity storage to alternative generation resources using simplified metrics, such as levelized cost of energy (Sioshansi et al. 2012; Bhatnagar and Loose 2012). To properly value energy storage requires detailed time-series simulations using software tools that can co-optimize multiple services provided by different storage technologies.

This analysis uses a commercial grid simulation tool to examine the potential value of different general classes of storage devices when providing both energy and ancillary services. Specifically, it analyzes individually and in combination the operational value and potential market value of load shifting/arbitrage and two classes of operating reserve products: regulation reserves and spinning contingency reserves. The operational value of storage is determined by comparing the difference in production cost in cases with and without storage. This value is then compared to scenarios where storage receives the marginal energy and reserve prices (approximating the revenue earned by a storage device in a restructured market). The lower value estimated in the market value case demonstrates some of the challenges for merchant storage developers, such as the inability to capture all the system benefits potentially provided by energy storage. The analysis also emphasizes the importance of considering the capacity value of storage devices, whether providing a traditional long-duration energy product like load shifting or providing shorter-duration reserve services.

This analysis considers value in hourly, day-ahead simulations under a variety of sensitivities, such as fuel price and storage size. However, the analysis does not capture several additional sources of value that could be captured under evolving market rules—most notably the actual response of storage plants providing reserves, including addressing forecast errors in real-time or "mileage" payments. It should also be noted that this approach examines the value of storage for planning purposes at the transmission level, following methods typically applied to large, central power plants. It does not consider additional value of distribution-sited generation, where small energy storage devices can provide additional value by deferring upgrades to transmission and distribution networks, particularly in areas where it might be difficult to site traditional generators.

2 Previous Estimates of Energy Storage Value

There have been a significant number of previous analyses of the operational value of energy storage. This previous work can be divided into two general categories: "market price"-based simulations and grid simulations using production cost models.

The first type of analysis simulates the dispatch of an energy storage device against historic marginal prices for energy and ancillary services. These simulations often assume that prices for energy are known to a storage operator in advance and then optimize the charge and discharge of a storage device to maximize its net revenue.[1] This type of analysis is often referred to as price-taker analysis in cases where it is assumed that the storage device is too small to affect the price (by increasing off-peak energy prices when charging and decreasing on peak prices when discharging).[2] Price data are derived from different sources depending on the region. About two-thirds of the U.S. population is served in regions with restructured markets (ISO/RTO Council 2009). These markets run co-optimized energy and ancillary service markets where individual generators bid their various costs and performance characteristics for a variety of services.[3] The system operator uses this information to calculate a least-cost mix of generators needed to provide total system demand and reserve requirements during each market time interval, which could range from 5 minutes to 1 hour depending on the market. All generators picked to provide energy and ancillary services are paid the marginal (market-clearing) price for the respective services at their corresponding pricing node. Historical market-clearing price data for each energy and reserve product is available on each system operator's website. In areas without restructured markets, utilities calculate and report their marginal energy price (system lambda) but do not report prices for ancillary services.[4]

Examples of this type of market-price-based analysis applied to grid storage in the United States are summarized in Table 2-1.

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[1] Some studies, such as Sioshansi et al. (2009), Connolly et al. (2011), and Byrne and Silva-Monroy (2012), evaluate the impact of imperfect knowledge of prices. Several studies also examine the impact of various optimization windows (from 1 day to several weeks) (Graves et al. 1999; Walawalker et al. 2007; Sioshansi et al. 2009).

[2] Sioshansi et al. (2009) relax this price-taker assumption to estimate the revenue impact of storage reducing peak/off-peak price difference using price-load relationships.

[3] An exception is the Southwest Power Pool, which, as of early 2013, is planning but does not operate a reserves market. See http://www.spp.org/publications/Economies_of_Scale_Market_Benefits.pdf.

[4] This data is submitted to the Federal Energy Regulatory Commission (FERC) and is available on their website at http://www.ferc.gov/docs-filing/forms/form-714/data.asp.

Table 2-1. Historical Values of Energy Storage in U.S. Restructured Electricity Markets

Market Evaluated	Location	Years Evaluated	Annual Value ($/kW)	Assumptions
Energy Arbitrage	PJM[a]	2002–2007	$60–$115	12 hour, 80% efficient device. Range of efficiencies and sizes evaluated. Also considers price difference suppression effect in a market setting using price/load relationships.
	NYISO[b]	2001–2005	$87–$240 (NYC) $29-$84 (rest)	10 hour, 83% efficient device. Range of efficiencies and sizes evaluated.
	USA[c]	1997–2001	$37–$45	80% efficient device. Evaluates ISO-NE, CAISO, PJM
	CA[d]	2003	$49	10 hour, 90% efficient device.
	CA[f]	2010–2011	$25–$41	4 hour, 90% efficient device.
	CA[h]	2011	$46	16 hour, 75% efficient pumped storage device.
Regulation Reserves	NYISO[b]	2001–2005	$163–$248	
	USA[e]	2003–2006	$236–$$429	PJM, NYISO, ERCOT, ISO-NE.
	CA[f]	2010–2011	$117–$161	Co-optimized arbitrage and regulation, most value is derived from regulation.
Contingency Reserves	USA[e]	2004–2005	$66–$149	PJM, NYISO, ERCOT, ISO-NE.
Combined Services	CA[f]	2010–2011	$117–$161	Arbitrage and regulation, most value is derived from regulation.
	CA[h]	2011	$62–$75	Arbitrage, regulation, and contingency. Included operational constraints of pumped storage.
	USA[g]	2002–2010	$38–$180	Arbitrage and contingency. CAISO, PJM, NYISO, MISO.

[a] Sioshansi et al. 2009
[b] Walawalkar et al. 2007
[c] Figueiredo et al. 2006
[d] Eyer et al. 2004
[e] Denholm and Letendre 2007
[f] Byrne and Silva-Monroy 2012
[g] Drury et al. 2011
[h] Kirby 2012

While the provision of market data has allowed a large number of new analyses without the need for full production simulations, there are some significant limitations to its application in these studies. Market-clearing prices for energy and ancillary services represent only the marginal costs and provide limited insight into the size of the market or how market prices would change as a result of the system re-dispatch that would occur with the introduction of a storage device or different generation mixes. This is particularly important when considering how market prices may change as a function of new requirements for reserves or changes to energy prices as a function of increased penetration of variable renewable generation. For example, the highest value service (regulation reserves) in Table 2-1 represents a relatively small market opportunity, and the introduction of large amounts of storage might quickly collapse the market for this service. Analyses that rely exclusively on fixed market prices largely ignore market elasticity and the reduction in prices that result as storage sells energy and ancillary services (as well as the price increase as storage buys off-peak energy to charge). Several studies have considered changes in market prices that might result from storage deployment (Sioshansi et al. 2009, Sioshansi 2010, Schill and Kemfert 2011). These price shifts reduce revenues to the storage owner but potentially lower costs to consumers,[5] as well as provide system-wide benefits that might not be captured in wholesale energy markets (Sioshansi et al. 2012).

An alternative to market-price-based analysis is the use of grid simulation tools that model the operation of the entire generation fleet, including the storage devices.[6] These models calculate the total cost of system operation, including cost of fuel and operation and maintenance (O&M) that result from providing both energy and ancillary services, which are co-optimized to minimize overall production cost. The operational value of a new generator can be estimated by comparing the difference in production cost between two simulations—with and without the added generator. Examples of previous studies that used production cost models to evaluate energy storage are listed in Table 2-2.

Table 2-2. Examples of Analysis of Energy Storage in the United States Using Commercial Production Cost Models

Location	Model	Notes
Western Interconnection[a]	PROMOD	Evaluates arbitrage and renewable energy balancing services for a variety of devices in various locations throughout the Western Interconnection.
Maui[b]	PLEXOS	Evaluates several storage technologies providing operating reserves and arbitrage/time-shifting. Considers changes in fuel use and renewable curtailment.
MISO[c]	PLEXOS	Preliminary analysis of storage, identified challenges in simulating both day-ahead and real-time markets in a large system.
MISO[d]	PROSYM	Evaluated a proposed compressed air energy storage project in Iowa.

[a] Kintner-Meyer et al. 2012
[b] Ellison et al. 2012
[c] Rastler 2011
[d] Black and Veatch 2005

It should be noted that production simulations only calculate the operational costs of an electricity system (capital costs and other fixed costs are not included), and typically only for a single year.

Another important difference between market-price-based simulations and production cost simulations is how they capture the capacity value of new resources. Depending on the region, historic market prices (but not system lambdas) may include scarcity pricing, or very high prices

[5] While charging increases the prices faced by consumers (and revenue received by generators), this is more than off-set by decreases in prices and revenue when the storage device discharges during peak periods. This is due to the greater volume of sales that occur during peak periods compared to off-peak periods.
[6] These have a number of names, including “production cost” and “security-constrained unit commitment and economic dispatch” models. To realistically model the grid, these tools require extensive generator databases and include transmission constraints and other elements to capture the challenges of reliably operating the electric grid.

that occur when the system demand approaches the total supply of generation. In locations without capacity markets, scarcity prices signal the need for new generation capacity and allow for recovery of these costs (Finon and Pignon 2008). As a result, some of the arbitrage revenue calculated in simulations using historic prices would include these scarcity prices and therefore potentially capture some of the value of storage providing system capacity (Sioshansi et al. 2012). However, there is considerable discussion about the adequacy and efficiency of scarcity pricing for incentivizing the appropriate amount of new capacity; some markets have introduced separate capacity markets or other mechanisms for incentivizing new capacity.[7]

Alternatively, production cost simulations capture only the operational value of a new storage device.[8] The value of system capacity or resource adequacy needs to be calculated separately and combined with the operational value to produce a more complete value of a storage device.[9] However the simulations also need to consider the difference in value generated by a storage device in a traditional vertically-integrated utility, and the value that can be captured in a restructured energy market. These values can be substantially different as discussed in Section 4.

[7] For example, see the PJM "Reliability Pricing Model" at http://www.pjm.com/markets-and-operations/rpm.aspx.

[8] Production cost models often allow for scarcity pricing bids to simulate these effects in market conditions, but we did not include these in this analysis. Alternately, the models can include a high penalty price for unserved load or reserves. This was included in the modeling (discussed in Section 3), however the model did not experience unserved load or reserves to trigger these penalty prices.

[9] A capacity expansion model can be used to calculate the total benefits of generators; however, these models typically do not have the temporal fidelity needed to accurately value energy storage.

3 Simulation of Energy Storage

In an attempt to understand the drivers of the operational value of energy storage, we simulated the operation of a power system with software that co-optimizes provision of energy and ancillary services. We used a commercially available software tool (PLEXOS)[10] to perform the simulations in a test system and evaluate the sensitivity of reserve prices to a variety of operational constraints, fuel prices, and other factors.

3.1 Test System Description

Our goal was to evaluate storage in a system large enough to represent a "real world" scenario yet small enough to allow reasonable run times given the large number of sensitivities analyzed (and also small enough to isolate changes associated with the different sensitivity cases). We developed a system composed of two balancing areas largely in the State of Colorado: Public Service of Colorado (PSCO) and Western Area Colorado Missouri (WACM). These balancing areas consist of multiple individual utilities, and this combined area is relatively isolated from the rest of the Western Interconnection. The test system also has sufficient wind and solar resources for large-scale deployment, which makes evaluation of high renewable scenarios more realistic.

The Colorado test system was derived from the database established by the Western Electricity Coordinating Council (WECC) Transmission Expansion Policy Planning Committee (TEPPC) model and other publicly available datasets. The TEPPC model includes the entire Western Interconnection, and we isolated the test system by physically "turning off" the generation and load and aggregating the transmission outside of the PSCO and WACM balancing areas. Transmission was modeled zonally, without transmission limits within each balancing authority area.[11] It is very difficult to simulate any individual or group of balancing authority areas as actually operated because the modeled system is comprised of vertically integrated utilities that independently balance their system with their own generation and bilateral transactions with their neighbors. Many details of these transactions are confidential, and as a result, we modeled the test system assuming least-cost (optimal) economic dispatch throughout the modeled area. Projected generation and loads were derived from the TEPPC 2020 scenario (TEPPC 2011). Hourly load profiles were based on 2006 data and scaled to match the projected TEPPC 2020 annual load. The system peaks in the summer with a 2020 coincident peak demand of 13.7 GW and annual demand of 79.0 TWh.

The generator dataset derived from the TEPPC 2020 database includes plant capacities, heat rates, outage rates (planned and forced), and several operational parameters, such as ramp rates and minimum generation levels. A total of 201 thermal and hydro generators are included in the test system, with total capacities listed in Table 3-1. The generator database was modified to include part-load heat rates based on Lew et al. (2012). Start-up costs were added using the start-up fuel requirements in the generator database plus the O&M-related costs based on estimates prepared for the Western Wind and Solar Integration Study (WWSIS) Phase 2 study

[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] This type of analysis will tend to understate the value of storage, particularly in its ability to relieve transmission congestion. A more detailed "nodal" analysis would include detailed transmission within each balancing area. This would capture higher price differentials that can occur in areas with transmission constraints and that could be particularly suited for energy storage devices. As an example, a study of arbitrage in PJM found one location with a 40% higher value compared to the average value across the entire region (Sioshansi et al. 2009).

(Intertek/APTECH 2012). We adjusted the generator mix to achieve a generator planning reserve margin of 15% by adding a total of 1,450 MW (690 MW of combustion turbines and 760 MW of combined cycle units).[12] The base test system assumes a wind and solar penetration of 16% on an energy basis. For comparison, Colorado received about 11% of its electricity from wind in 2012 (EIA 2013).[13] PV profiles were generated using the System Advisor Model (SAM) (Gilman and Dobos 2012) with 2006 meteorology. Wind data was derived from the WWSIS dataset (GE Energy 2010).[14] Discrete wind and solar plants were added from the WWSIS datasets until the installed capacity produced the targeted energy penetration. The sites were chosen based on capacity factor and do not necessarily reflect existing or planned locations for wind and solar plants.

Table 3-1. Characteristics of the Test System Generators in 2020

System Capacity (MW)	
Coal	6,157
Combined Cycle (CC)	3,988
Gas Turbine/Gas Steam	4,259
Hydro	777
Pumped Storage	560
Wind	3,347 (10.7 TWh)
Solar PV (AC Rating)	878 (1.8 TWh)
Other[a]	513
Total	**15,793**

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

Fuel prices were derived from the TEPPC 2020 database. Coal prices were $1.42/MMBtu for all plants. Natural gas prices varied by plant and for most plants were in the range of $3.90/MMBtu to $4.20/MMBtu, with a generation weighted average of $4.10/MMBtu. This is slightly lower than the EIA's 2012 Annual Energy Outlook projection for the delivered price of natural gas to the electric power sector in the Rocky Mountain region of $4.46/MMBtu in 2020 (EIA 2012b). Sensitivity to natural gas price was also analyzed. No constraints or costs were applied to carbon or other emissions.

3.2 Ancillary Services

We included three classes of ancillary service requirements that require generators to be synchronized to the grid and be able to rapidly increase output: contingency, regulation, and flexibility reserves.[15] This section summarizes the implementation and resulting prices; a more

[12] This adjustment was necessary in part because the simulated system does not include contracted capacity from surrounding regions. The 15% reserve margin was based on the "Reference Reserve Margin" for a predominately thermal system from the North American Electric Reliability Corporation (NERC 2012).

[13] Colorado generated 6,045 GWh from wind in 2012 compared to total generation of 53,594 GWh. EIA "Electric Power Monthly with Data for December 2012," February 2012.

[14] All generation profiles were adjusted to be time synchronized with 2020, which is a leap year.

[15] For additional discussion of these reserves (especially flexibility reserves, which is not yet a well-defined market product), see Ela et al. (2011).

detailed analysis of reserve prices in this test system is described in a separate document (Hummon et al. forthcoming).

Contingency reserves are based on the single largest unit (a 810-MW coal plant) and allocated with 451 MW to PSCO and 359 MW to WACM, with 50% met by spinning units.[16] We did not model the non-spinning portion of this reserve requirement.[17] The contingency reserve requirement is assumed to be constant for all hours of the year and corresponds to a spinning reserve equal to about 3% of peak load and about 4.5% of the average load. Contingency spinning reserves are allowed to be provided by any partially loaded plant able to be dispatched, constrained by the 10-minute ramp rate of each individual generator.

Regulation and flexibility reserve requirements vary by hour based on the net load and impact of variability and uncertainty of wind and solar. In the base case, the upward reserve requirements were calculated based on the statistical variability of net load described by Ibanez et al. (2012). The regulation reserve requirement (requiring a 5-minute response) for the system ranged from 73 MW to 166 MW with an average of 120 MW, equal to about 1.3% of the average load. The spinning component of the flexibility reserve requirement (requiring a 20-minute response) ranged from 15 MW to 85 MW with an average of 57 MW, or 0.6% of the average load.

Overall, the sum of the total operating reserves (met by spinning units) averages 582 MW, which corresponds to about 6.4% of average load.

The availability and constraints of individual generators providing reserves is a major source of the cost of providing reserves. Not all generators are capable of providing certain regulation reserves based on operational practice or lack of necessary equipment to follow a regulation signal. For assigning which plants can provide regulation, we based our assumptions on the PLEXOS database established for the California Independent System Operator's "33% Renewable Integration Study" (CAISO 2011a). This dataset assigns regulation capability to a subset of plants, which is about 60% of total capacity within California (as measured by their ramp rate). Similarly, we allowed only 60% of all dispatchable generators (coal, gas combined cycle, dispatchable hydro, and pumped storage) to provide regulation. Based on feedback from various utilities and system operators, we further restricted combustion turbines (CTs) from providing regulation. We allow all dispatchable plants (including CTs) to provide flexibility and contingency reserves. An additional cost was assigned to plants providing regulation, associated with additional wear and tear and heat rate degradation. This is functionally equivalent to a generator regulation "bid cost" in restructured markets, discussed in PJM (2012). The assumed regulation costs by unit type are provided in Table 3-2.

[16] The PSCO and WACM balancing areas are part of the Rocky Mountain Reserve group, which shares contingency reserves based on these values.
[17] This would tend to slightly underestimate total production cost; however, market-clearing prices for non-spinning reserves are typically very low as there is often little opportunity cost for holding non-spinning reserves.

Table 3-2. Assumed Operating Cost for Units Providing Frequency Regulation Service

Generator Type	Cost ($/MW-hr)
Supercritical Coal	15
Subcritical Coal	10
Combined Cycle (CC)	6
Gas/Oil Steam	4
Hydro	2
Pumped Storage	2

3.3 Dispatch Simulations

The PLEXOS model includes security-constrained unit commitment and economic dispatch, including outage scheduling. The simulations begin with two scheduling models to determine outage scheduling and allocate certain limited energy resources.[18] The model then performs a chronological unit commitment and economic dispatch. This analysis presents the results of the day-ahead unit commitment simulations using day-ahead forecasts for wind and solar generation and an optimization horizon of 48 hours. 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 dispatch energy storage.[19] Future analysis will examine how the value of storage changes when allowed to change its dispatch to respond to forecast errors in real-time dispatch intervals.[20]

Loads were modeled as a "soft constraint," meaning the system was allowed to not serve load if the cost exceeded $6,000/MWh; however, there was no unserved load in these simulations. All scenarios were run for one full year (8,760 hours).[21]

3.4 Implementation of Energy Storage

Most commercial production cost models contain energy storage modules. PLEXOS includes energy storage, with a large number of input parameters, including size (both energy and power), efficiency during charge and discharge, and other operational considerations common to all generator types, such as efficiency as a function of load, operational range, ramp rates, and minimum up and down times. The most common implementation of energy storage in

[18] Within PLEXOS, maintenance outages are scheduled in the "Projected Assessment of System Adequacy" model, which generally assigns planned outages to periods of low net demand. This is followed by the "mid-term" scheduling model, which uses monthly load duration curves to assign limited energy resources, such as certain hydro units. The resulting allocation of resources from these two models is then passed to the chronological commitment and dispatch model. The model also includes random forced outages based on plant-level outage rates. The random number seed used to generate forced outages was kept the same throughout the various simulations for consistent treatment of these outages and associated cost impacts.

[19] Without a look-ahead period, production cost models see no value in carrying energy in storage across commitment intervals.

[20] This would likely increase the value of storage as it represents a source of highly flexible generation able to be quickly dispatched. However, use of storage in this manner introduces additional complexity for scheduling.

[21] Using PLEXOS version 6.207 R08 x64 Edition and the Xpress-MP 23.01.05 solver, with the model performance relative gap set to 0.5%. We also examined the impact of reducing the relative gap to 0.1% in an attempt to evaluate the incremental impact of relatively small storage devices (down to 25 MW). We observed a small variation in storage value compared to the case with a 0.5% gap. However, several of the scenario run times increase from about 5 hours to over 40 hours, so we completed the full set of analyses with the higher value.

production cost models is pumped hydro, and the PLEXOS databases include existing pumped storage devices, which can be modified to resemble the characteristics of other storage devices, such as batteries.

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. Reserves and energy.

The energy-only device was based on the existing pumped hydro modules existing in the PLEXOS database. In our base case, we modified this device to resemble a more flexible storage device that resembles a high-energy battery. More specifically, we made the assumption of a 75% round-trip efficiency and did not constrain the ramp rate of the device.[22] This means that the storage device can ramp 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). We also assumed a constant efficiency as a function of load, and no minimum up or down times. The base case assumes a single 300 MW device, with 8 hours of capacity at full output.[23] No fixed or variable O&M costs were assigned to the storage device. No other changes were made to the system generation mix.[24]

The reserves-only device represents a highly responsive short duration energy storage device capable of providing regulation or spinning contingency reserves.[25] This represents a battery, flywheel, or other device that meets the local market requirements for providing these services.[26] We evaluated cases where the device can only provide individual reserve products as well as cases where the device can provide both, with the actual mix determined by the PLEXOS optimization in each time interval. 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.[27] 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. For a device providing spinning contingency reserves, we assume that the device simply provides up to its full discharge capacity 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

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[22] The round-trip efficiency is based on a Sodium-Sulfur battery (Nourai 2007).

[23] 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.

[24] Because the storage device can potentially provide firm capacity (as discussed in Section 4.3), conventional generation could potentially be removed. However for consistency (to avoid having to remove different amounts of conventional generation depending on the storage size) we did not remove any of the existing generation.

[25] Devices providing only flexibility reserves were not considered because the simulated cost of flexibility reserves was much lower than spinning or regulation reserves.

[26] The energy capacity required varies by product and location. For example, MISO requires spinning reserves to be restored in 90 minutes, while WECC requires 105 minutes (NERC 2011). For regulation, new tariffs and ISO rules allow devices with 1 hour or less to participate in regulation markets (CAISO 2011b).

[27] In this scenario, a 100-MW device can provide 100 MW of reserves. In some scenarios a 100-MW device can provide more than 100 MW of reserves by providing reserves while charging. This is discussed in more detail in Section 6.

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, which is the product of two factors: the fraction of reserve capacity actually used to provide real energy and the device efficiency. The first factor, "regulation energy use ratio," 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. In the base case, we assume the regulation energy use ratio is 25% and the efficiency loss rate is 20%, based on a net round-trip efficiency of 80% (Ellison et al 2012).[28] As a result, for each hour, a storage device providing 100 MW of regulation consumes 5 MWh of energy.

There are a number of approaches to modeling these energy losses and corresponding reduction in revenues (or net benefits) that will occur when a storage device provides reserves. One method is to apply a constant load to the storage device whenever it is providing reserve services within the production simulation using an estimate for both the average reserve energy actually cycled through the storage device and the storage loss rate. We used an alternative approach that allows us to consider a greater range of these factors. We used the marginal energy price and assume the storage device providing reserves must effectively purchase energy at this rate for "make-up energy" associated with losses while providing reserves. This price was multiplied by the effective energy consumption rate and loss rate and was performed in post-processing to avoid needing to run the model multiple times to examine the sensitivity of these factors. A disadvantage of this approach is that it removes this loss rate from the dispatch optimization in the model, somewhat reducing the efficiency of the system as a whole. Future analysis will consider the size of this impact.

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 an hour can also provide up to 40 MW of regulation by operating between 100 MW and 20 MW (equal to 60MW +/- 40MW) during the same hour. As long as regulation is at net zero during that hour, the device will provide the same amount of energy, therefore requiring no additional make-up energy.[29] However, any regulation provided that exceeds the average discharge will require make-up energy at the same rate as the reserves-only device. For example, a 100-MW device discharging at 20 MW could only 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 make-up losses separately.

[28] In addition, we also assume that the economic value of energy consumed and produced in each time interval while providing regulation is equal.
[29] This also requires constant efficiency as a function of discharge rate.

4 Results: Energy-Only Storage Devices

4.1 Base Case Results

We begin with a discussion of energy only applications, where the device is allowed to charge and discharge energy in response to the system requirements, but not allowed to provide any reserve services.

To examine storage plant operation in a qualitative manner, we can examine its operation during periods of high and low price periods. The objective of a production cost model is to dispatch the generation fleet to minimize the overall cost of production. When storage is added to the generation mix, overall system costs will be minimized when storage is used to displace the operation of the highest cost generators. Figures 4-1 and 4-2 demonstrate hourly price and load relationship curves for the base case without any additional storage.[30] The marginal price of energy in a power system is driven by a combination of factors, including load patterns, fuel prices, and system resources. In general, there are two daily load and price shapes common in many parts of the United States. During the winter (Figure 4-1), loads and prices tend to have a bimodal shape, with a price spike in the morning and larger load/price spike in the evening. During the summer (Figure 4-2), loads and prices tend to have a "sine wave" shape with loads and prices peaking in the late afternoon driven by air-conditioning demand.

The presence of zero marginal cost variable generation tends to change the relationship between load and price, and it becomes more important to examine the "net load" or load removing the contribution from wind and solar generators. Figures 4-1 and 4-2 show the net load, or load minus wind and solar generation, and the system marginal price as generated by the PLEXOS simulations (where wind and solar contribute 16% of the annual generation). Figure 4-1 shows the curves for a period beginning on February 3, while Figure 4-2 provides this data for a period starting on July 21.

[30] These shapes are much more variable than market clearing prices in restructured markets. This is likely due to the relatively small number of generators compared to those in markets, which allows for a more continuous price curve. For comparison, we examine the system lambda data reported by PSCO for 2011 (available from FERC at http://www.ferc.gov/docs-filing/forms/form-714/data.asp). It shows similar patterns of variability.

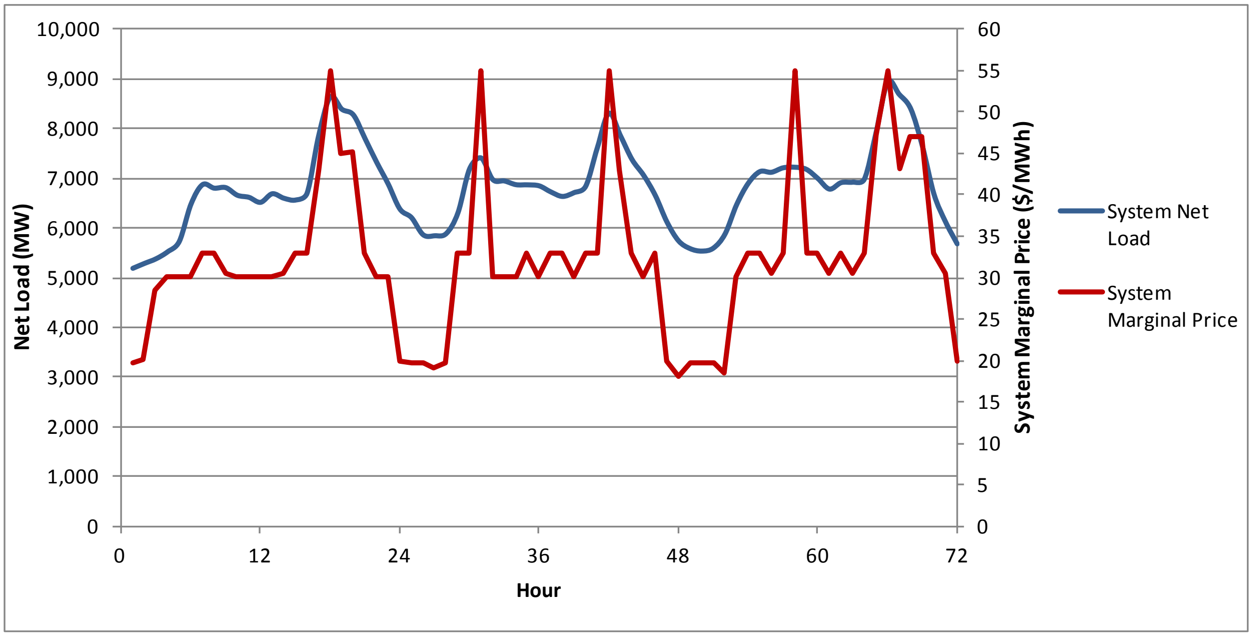

Figure 4-1. System net load and corresponding marginal price for the 3-day period starting February 3

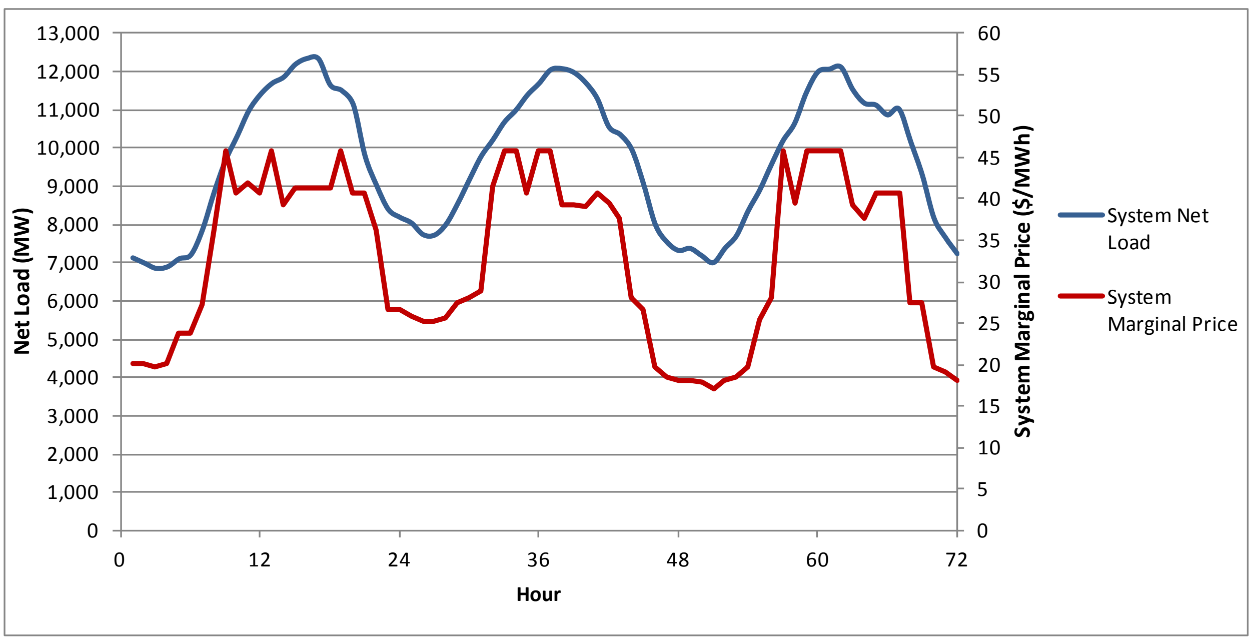

Figure 4-2. System net load and corresponding marginal price for the 3-day period starting July 19

Figures 4-3 and 4-4 show the corresponding storage plant operation, compared to the system marginal prices for the same 3-day periods. For clarity, only discharging is shown—charging tends to follow periods of lowest demand and prices as shown in Figures 4-5 and 4-6. In each case they show that storage plant output tends to follow periods of high prices. However, storage output does not exactly match periods of high price. This is due to a variety of factors but mostly due to the fact that PLEXOS is not optimizing the operation of the storage plant in isolation. The model considers the interaction of the storage plant with the rest of the system and often uses storage to reduce the number of plant starts, both during off-peak periods, by increasing load and reducing the frequency of plant shut downs, and during on-peak periods, by reducing starts of peaking generators. During some periods, storage plant operation appears to coincide with periods where the price is not necessarily at its peak, but is increasing, indicating periods where additional thermal plants are being started.

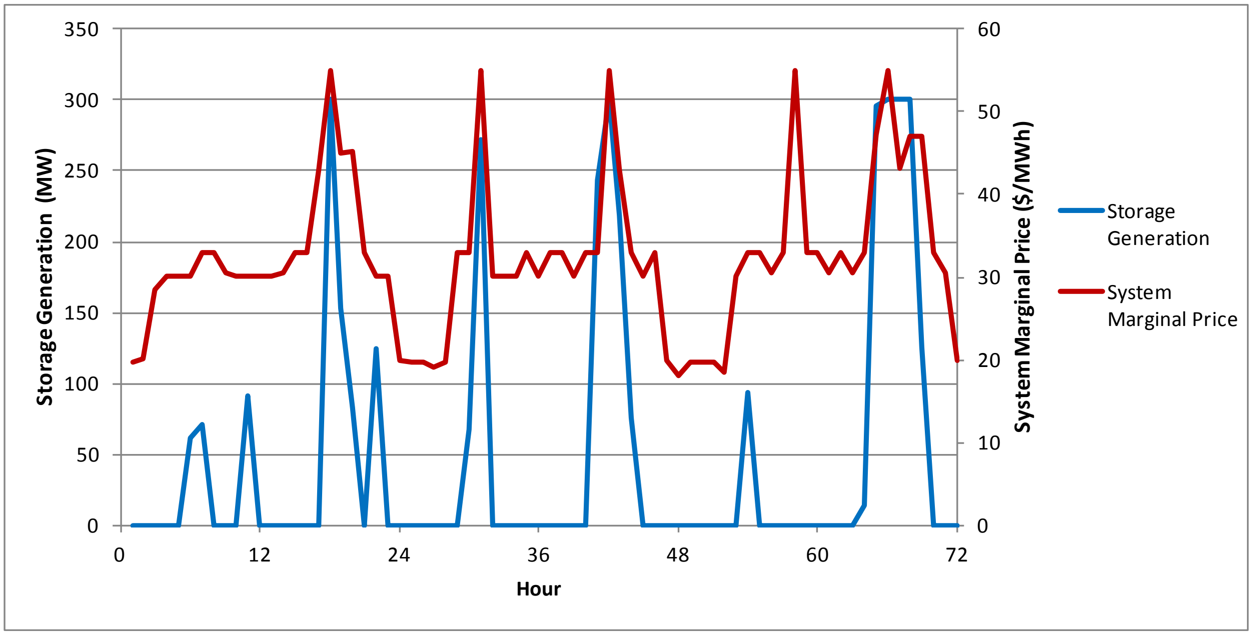

Figure 4-3. System marginal price and corresponding storage discharge for the 3-day period starting February 3

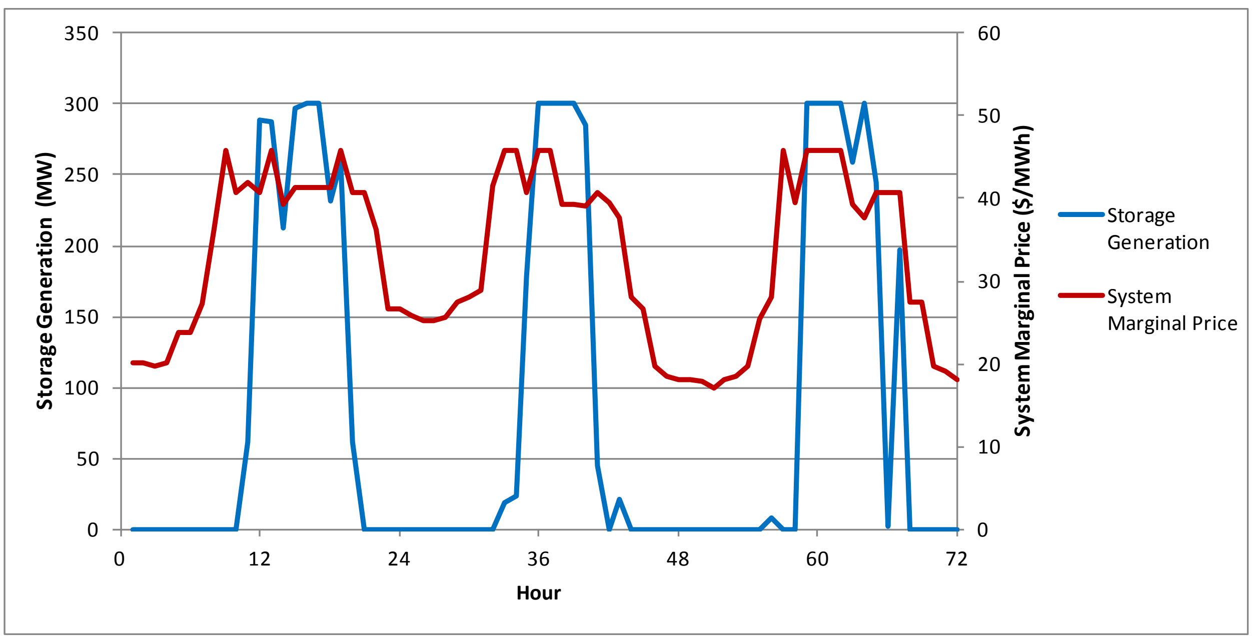

Figure 4-4. System marginal price and corresponding storage discharge for the 3-day period starting July 19

From the system operator's perspective (and the objective function of the PLEXOS unit commitment model), the addition of storage allows for cost minimization due to load leveling, which increases the use of lower cost generators, decreases the use of peaking generators, and reduces plant starts. Figures 4-5 and 4-6 show the impact on net load for the spring and summer periods. Both the charging and discharging profile of the storage device is shown. Of note is the somewhat irregular operation of the storage device. This result is partially due to the assumption of a “perfect” storage device in terms of ramp rate, ramp range, and startup limitations. While there is a round-trip efficiency of 75%, the storage device is able to provide energy over the entire generation range at this constant efficiency, with no restrictions on how often the plant can operate. For certain devices, particularly pumped hydro, there can be additional restrictions on how fast the unit can transition from charge (pumping) to discharge. There are also limits to its operating range both in charging and discharging mode.

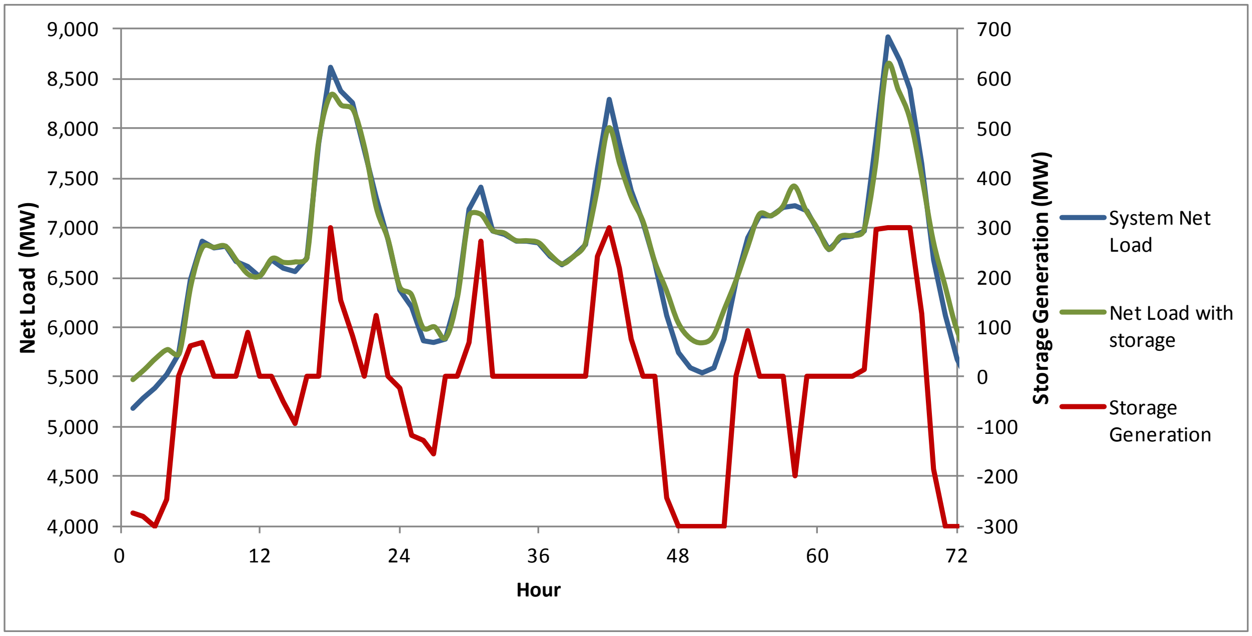

Figure 4-5. Storage operation and corresponding change in system net load the 3-day period starting February 3

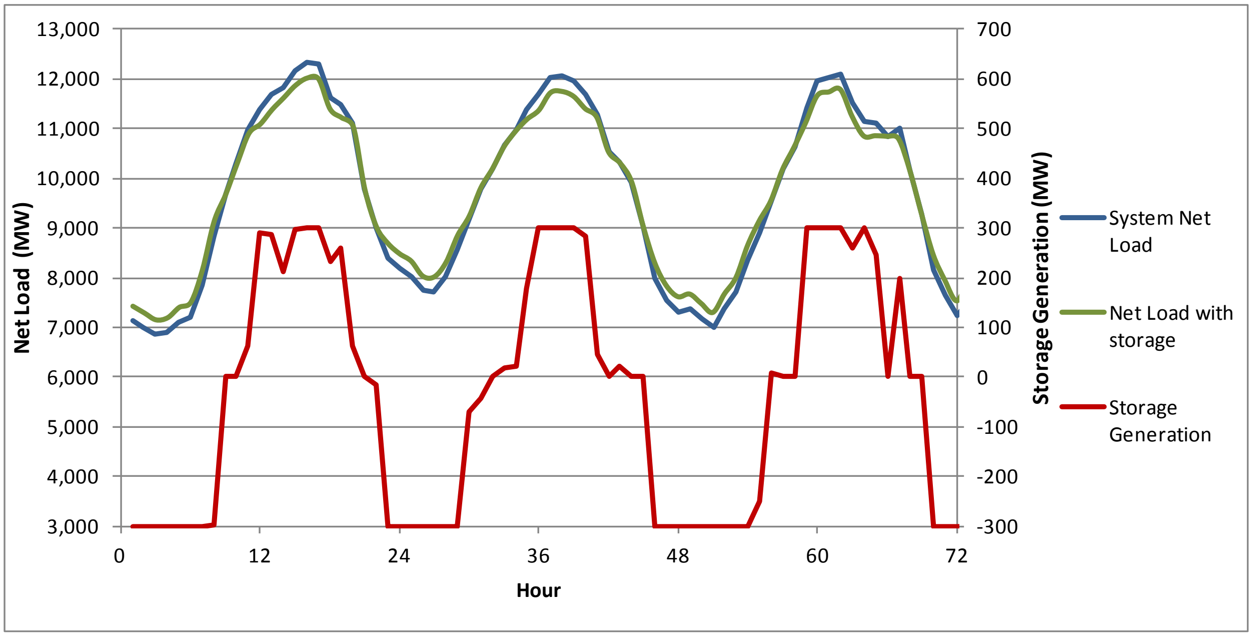

Figure 4-6. Storage operation and corresponding change in system net load the 3-day period starting July 19

The net impact on system dispatch can be observed by examining the change in operation of individual generator types. Table 4-1 shows the difference in generation by type as well as total fuel. Adding storage increases the total generation requirement a small amount due to losses in the storage device and also shifts energy production to lower cost units. In this case, adding storage increases generation from coal and gas combined cycle units while decreasing generation from gas combustion turbines. Overall, this increases the use of coal by about 0.6%, while decreasing the use of gas by about 1.5%.

Table 4-1. Base Case Energy Results

	Base Case	With Storage (300 MW)	Increase with Storage
Generation (GWh)			
Coal	46,134	46,375	241
Hydro	3,792	3,792	-
Gas CC	14,761	14,947	186
Gas CT	1,024	763	-260
Other	103	89	-14
Existing Pumped Storage	1,054	1,050	-4
New Storage	-	465	465
PV	1,834	1,834	0
Wind	10,705	10,705	0
Total Generation (GWh)	79,407	80,020	613
Fuel Use (1,000 MMBtu)			
Coal	488,140	490,930	2,790
Gas	126,651	124,728	-1,923
Total Fuel	614,719	615,658	867

Table 4-2 summarizes the total system costs as generated by the PLEXOS tool. It shows the total fuel costs (reflected in Table 4-1) but also the additional cost components, including variable O&M, start-up costs, and the additional costs of providing regulation services (equivalent to the plant regulation bid cost discussed in Section 3.2).

Table 4-2. Base Case Change in Production Costs

	Base Case	With Storage (300 MW)	Increase with Storage
Total Fuel Cost (M$)	1,210.5	1,204.7	-5.8
Total O&M Cost (M$)	152.1	152.8	0.7
Total Start Cost (M$)	58.2	52.8	-5.5
Total Regulation “Adder” Cost (M$)	4.7	4.8	0.1
Total Production Cost (M$)	1,425.6	1,415.1	-10.5

Overall, the difference in production cost between these two cases represents an annual operational value of storage of about $10.5 million. Of this value, about half of the total difference is in the fuel costs, with the other half derived from the ability of flexible energy storage to avoid unit starts. The ability of the unit commitment model to use storage to optimize unit starts is an important consideration not captured by a market-price-based approach. For comparison, we took the marginal energy prices from the system without the added storage and applied an optimized “price-taker model” previously described by Sioshansi et al. (2009). This model has perfect foresight of prices over a 2-week period and has the same technical characteristics as the storage device modeled in PLEXOS (75% efficiency, 300 MW, 8 hours capacity, and no operational flexibility constraints). The price-taker simulation yielded an annual device value of $8.5 million, or about 25% less than the result from the PLEXOS simulations, even without considering the suppression of electricity price differentials that occur when adding the storage device to this system.[31] The impact of considering storage revenue in a market setting can be estimated by multiplying the hourly charge and discharge energy by the marginal energy price in the corresponding hours using data from the simulation with storage. In this case, the 300-MW device would have purchased a total 613 GWh at a cost of $15.4 million, while selling 465 GWh, with revenues totaling $20.6 million. As a result the net revenue of the storage plant in a market setting is $5.2 million, or only about 50% of the reduction in operational costs produced when adding storage to the base system.[32] The combination of incomplete capture of system benefits and price elasticity presents additional challenges to storage devices in restructured markets, as noted previously by Sioshansi et al. (2012) and Kirby (2011).

4.2 Annualized Benefits and Sensitivities

The difference in production costs can be translated into an annualized benefit. For example, in the base case the difference of $10.5 million is divided by 300 MW to produce an annual benefit of about $35/kW-year. We examined the sensitivity of this benefit to a number of factors, beginning with plant size. As storage is added, it flattens the load and reduces the on-/off-peak price differential. Figure 4-7 shows how this value changes as a function of size.

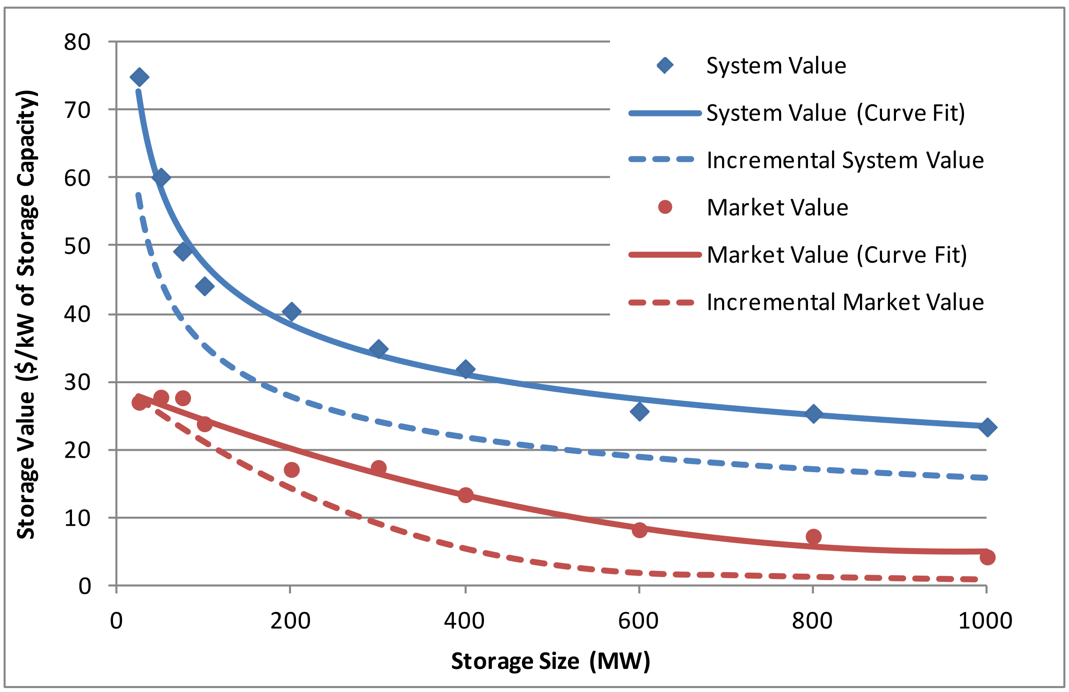

Figure 4-7. Storage operational value as a function of size for an energy-only device

[31] 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.

[32] This assumes that the storage dispatch to maximize its overall value to the system is the same as the dispatch that would maximize revenue to the owner in a market setting. The potential conflict of scheduling a storage device between owner (to maximize revenue) and system operator (to minimize overall production cost) is discussed by Sioshansi et al. (2012) and Kirby (2011).

The top curve shows the total system value of storage devices of various sizes, including both the results from the discrete sizes evaluated in the PLEXOS simulations and a curve fit to these data points, intended to demonstrate the general trends found in the analysis.[33] In addition to the total system value, it is important to consider the marginal or incremental system value of additional storage in each case. The dotted blue curve estimates this incremental value, based on the total system value curve. As an example, the value of a 400-MW device is a reduction in operational costs of about $12.8 million, or an annualized value of $32/kW-year. However, the incremental value of adding 100 MW to a system that already has a 300-MW device is about $2.3 million ($12.8 million minus the $10.5 million value of the 300-MW device), which translates to an incremental value of about $23/kW-year, which falls even further as more storage is added. Because of the rapid decrease in value, we also consider sizes smaller than the base 300-MW device, and these sizes show increases in value.

We also examined the market value, or the revenue that a storage plant would receive in a restructured market assuming the PLEXOS simulations produce a proxy for the market clearing price for energy. These values in the lower curves show the significant difference between the system-wide operational value the storage plant produces (as measured by difference in production cost) and the potential revenue when buying and selling energy at the system marginal price. Both the total and incremental values are shown. As in the system value case, this incremental value could be used to find the "optimal" storage investment by a utility or developer at the point where the incremental cost equals the incremental revenue. The incremental curve shows that in the test system the incremental value of a storage device in a market setting falls to zero at about 600 MW, meaning at this point the storage plant has completely collapsed the market, while still producing a small positive value by continuing to optimize system dispatch, including reduced starts.

Several additional sensitivities were evaluated, with results summarized in Table 4-3. The first sensitivity examines the impact of removing the existing 560 MW of pumped storage, as a general indication of the increased value of storage in a system less flexible than the evaluated system.[34] The second evaluates the impact of increased round-trip efficiency, potentially representing a more advanced battery technology.[35] Another important factor is the price of natural gas, which tends to set the marginal price for many hours of the year in the evaluated system. The price of natural gas in the base simulation is about $4.10/MMBtu on a generation-weighted basis, and we considered a scenario where we doubled this price for all generators. (We did not modify the price of coal.) For comparison, the historic price of natural gas delivered to generators in the test system ranged from about $3.30/MMBtu to $10.30/MMBtu.[36] Finally, we evaluated the combined impacts of increasing natural gas prices and removing pumped storage, which more than doubles the value of the simulated storage device.

[33] Figure 4-7 shows several discontinuities in the trend of decreasing value. This is potentially explained by the challenge of evaluating very small differences in a very large system. For example, adding the 50-MW device produced a difference in annual production cost of about 0.2%. Further analysis is needed to understand the accuracy of evaluating very small differences.

[34] The plants were removed but not replaced with conventional generators. The reserve margin was sufficiently high to allow this removal without unserved load or reserves.

[35] For example, Akhil et al. (forthcoming) discuss several battery technologies that could achieve round-trip efficiencies of about 90%.

[36] Historical prices of natural gas delivered to electric utilities is available from the Energy Information Administration at http://www.eia.gov/naturalgas/.

Table 4-3. Sensitivity Cases

Scenario	Annual Value ($/kW-yr)	Increase in Value for a 300-MW Device
Base 300-MW Device	34.9	-
Remove Existing Pumped Storage	48.4	39%
Increase Efficiency from 75% to 90%	47.1	35%
Double Natural Gas Prices	56.1	61%
Remove Existing Pumped Storage and Double Natural Gas Prices	79.3	127%

4.3 Capacity Value

The results in the previous section only consider the operational benefits and do not consider the value of storage providing firm system capacity. Utilities have historically treated long-duration storage devices (such as pumped hydro) as sources of reliable capacity because they can be scheduled to have sufficient energy to discharge during periods of peak demand (EPRI 1976). A detailed statistical treatment of the capacity value of storage is provided by Sioshansi et al. (forthcoming). They show that for an 8-hour device, capacity credit of greater than 90% can be expected when compared to an alternative generator with a similar forced outage rate. Figure 4-8 demonstrates why a storage plant can have a high expected capacity credit. It shows the average capacity factor of the storage plant in the base case simulation during the highest 100 net load hours of the year, demonstrating that the plant is discharging at close to its rated output during periods of highest demand for conventional capacity.[37]

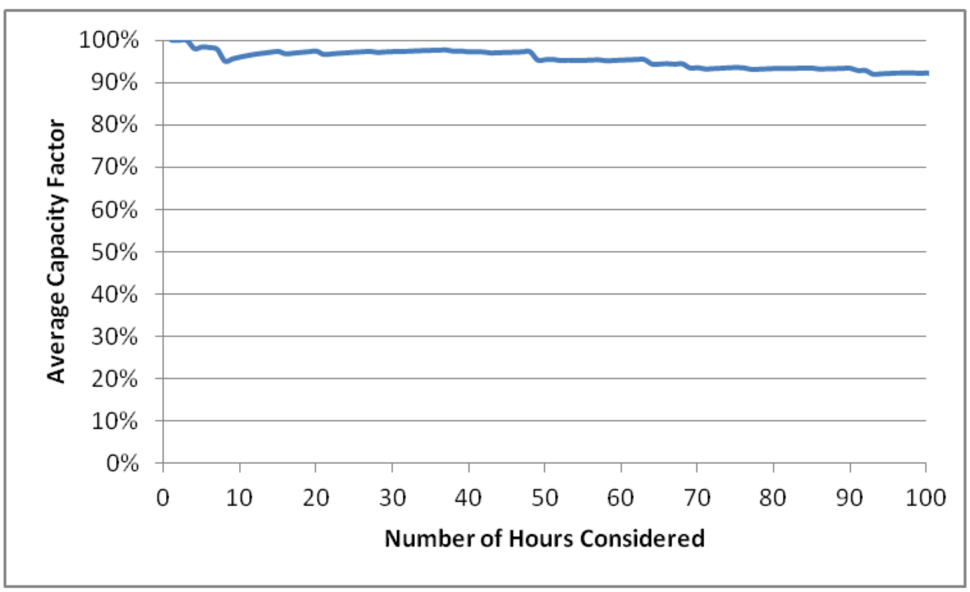

Figure 4-8. Storage plant capacity factor during high load hours

[37] This figure is meant to be illustrative and does not represent a rigorous analysis of the capacity value of storage. In some of the hours where the storage plant did not generate there was energy in storage that could have been used to meet load.

The monetized capacity value of a storage plant can be added to its operational value to derive an estimate of its total annual value. This capacity value is contingent on a system actually needing additional capacity to provide an adequate planning reserve margin (for example to replace a retiring generator or to meet growth in demand. The storage plant would provide an alternative to construction of a new conventional peaking resource. A system with an adequate planning reserve margin would have essentially zero capacity value for a new storage resource and would only generate the operational value associated with load-leveling. There is a large range of estimates for the annual capacity value of new generators, depending on location and market. Annualized values for capacity in the PJM market for 2011–2013 ranged from $40/kW-yr to $90/kW-yr (Pfeifenberger et al. 2012). Another standard value for new capacity is the annualized cost of a new combustion turbine. These costs also have a range of values depending on equipment costs, location, and financing terms. Examples of this range include a low value of $77/kW-yr (PSCO 2011) and a higher value $212/kW-yr (CAISO 2012). Overall, this capacity value is generally higher than the total operational value calculated by the PLEXOS simulations, which implies that a long-duration energy-only storage device is more valuable for its ability to replace conventional capacity than its operational (load-leveling) benefits.

4.4 Supported Cost of a New Storage Device

The total operational and capacity value of storage can be translated into a maximum capital cost for the applicable storage technology (equal to the maximum cost of a storage device that can be supported by the revenues available). This requires converting any annualized values into life-cycle values through detailed life-cycle cost calculations. However, a simple estimate of the maximum supported capital cost can be performed by dividing the annual revenues by a fixed charge rate. This produces a total project capital cost assuming the annualized value remains constant through the life of the project.

Figure 4-9 provides an estimate of the equivalent life-cycle value, or breakeven capital cost, of a new storage device providing only load-leveling services. It generates this cost by dividing the values in Table 4-3 by three different fixed charge rates (Denholm et al. 2010). These rates are derived from previous analyses in the literature and not implied to be definitive. Lower rates typically correspond to low risk and/or long-lived projects while higher rates may correspond to riskier or shorter-lived projects.[38] This capital cost does not consider any fixed or variable operation and maintenance costs for the storage device. The values in Figure 4-9 support previous conclusions (indicated by the values in Table 2-1) that arbitrage revenues alone are unlikely to support development of new storage projects.

[38] For more detailed financial analysis applied energy storage projects, see Akhil et al. (forthcoming).

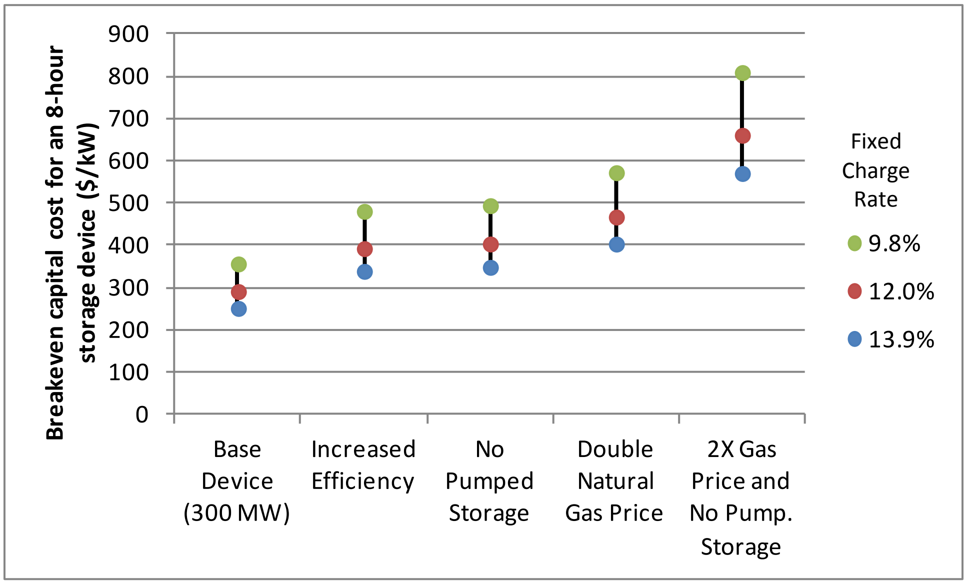

Figure 4-9. Breakeven capital cost of energy storage devices providing only load-leveling with no capacity value

The operational value of the storage device can be added to the capacity value, which in this case represents the cost of an alternative generator. Instead of an annualized value, we simply assume a cost for a new CT using a range of values, including a low cost of $724/kW and a high cost of $1,578/kW (CEC 2010). The high cost estimate is greater than many other estimates of new capacity costs but could be useful as a proxy for costs in areas where it is more difficult to construct new generation capacity. This could be particularly relevant for distributed storage devices, which produce no local air emissions or significant noise and therefore may be sited where it would be difficult to site traditional sources of peaking generation. These values also place no additional benefits on the flexibility of the added generator. However, as noted previously, this value is entirely contingent on the system needing new capacity. A new storage device in a system with no additional capacity requirements will produce only the operational benefits similar to the one illustrated in Figure 4-9.

Figure 4-10 illustrates the range of maximum capital costs of storage under these assumptions for fixed charge rate and generator costs. The "low" value corresponds to the low CT cost and high (13.9%) capital charge rate for the storage device, while the "mid" value corresponds to a CT cost mid-way between the high and low value and the 12% fixed charge rate, and the "high" value corresponds to the high CT cost and the low (9.8%) fixed charge rate. For comparison, several cost estimates for batteries currently available and under development are provided by Akhil et al. (forthcoming). These cost estimates are generally higher than the breakeven costs estimated in Figure 4-10.

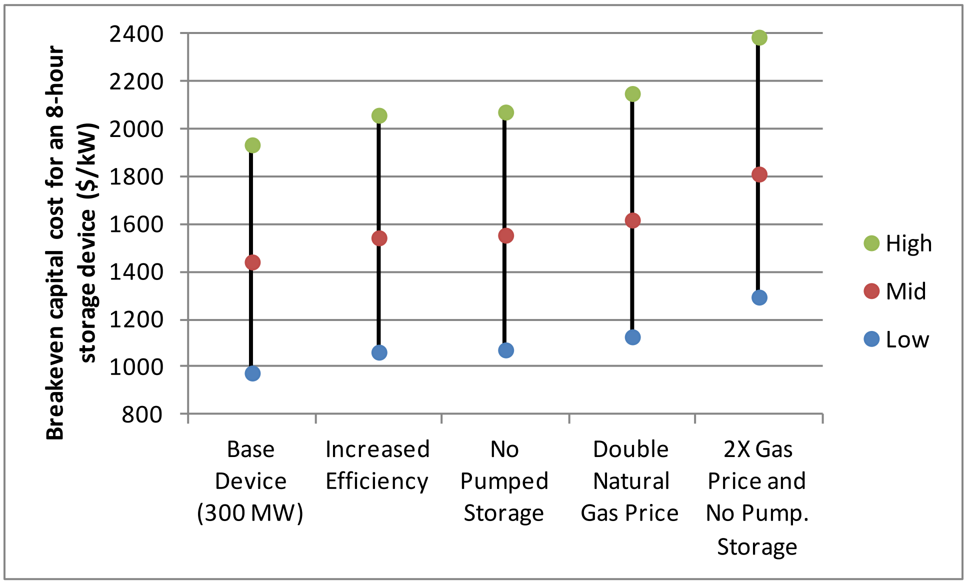

Figure 4-10. Breakeven capital cost of energy storage devices providing energy and capacity

As noted previously, the majority of the value of an energy-only storage device is derived from its capacity value. This explains the relatively small sensitivity of the breakeven cost to the scenario in Figure 4-12 because the value of capacity is assumed to be the same in all scenarios. While the high value assumes a relatively high cost of new capacity, it does not consider any additional costs of siting capacity in transmission-constrained regions or densely populated regions.[39]

[39] As noted previously, this analysis does not consider additional benefits of distribution-sited storage devices.

5 Results: Reserves-Only Cases

The results in Section 4 tend to support previous analyses that find that energy-only (arbitrage) applications tend to provide values that generally cannot support new market entrants, particularly with low gas prices and high costs of many long-duration storage technologies. A major focus for many storage technology providers is on the provision of reserves, such as regulation reserves, where potential revenue is higher and lower energy capacities are required. In addition, the fast response of many storage devices makes them well suited to provide various reserve services. It should be noted that the results in this section do not include additional mileage payments associated with FERC order 755.[40]

5.1 Reserves Prices

The value of storage devices providing reserves is highly dependent on reserve prices, which themselves depend on the mix of generators able to provide these reserve services. An extensive discussion of the reserve prices and sensitivities in this system are described by Hummon et al. (forthcoming).

The average price ($/MW-hr) of spinning reserves in the base system across the two balancing areas simulated in the test system was $6.3/MW-hr.[41] The values can be compared to 2011 average market clearing prices of $7.4/MW-hr in NYISO, $2.8/MW-hr in MISO, and $7.2/MW-hr in CAISO. Price duration curves for the base system and these historical market prices are provided in Figure 5-1. Of note is the large number of hours where the price of spinning reserves is close to zero, which is often observed in the clearing price for spinning reserves in wholesale markets, due to low or zero opportunity costs, as discussed in Hummon et al. (forthcoming). For example, in 2011, the clearing price for spinning reserves in both MISO and CAISO was less than $1/MW-hr for over 2,000 hours.

[40] FERC order 755 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." https://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf.

[41] This average value is after removing 10 hours of very high reserve prices associated with soft constraints on the operation of hydro units.

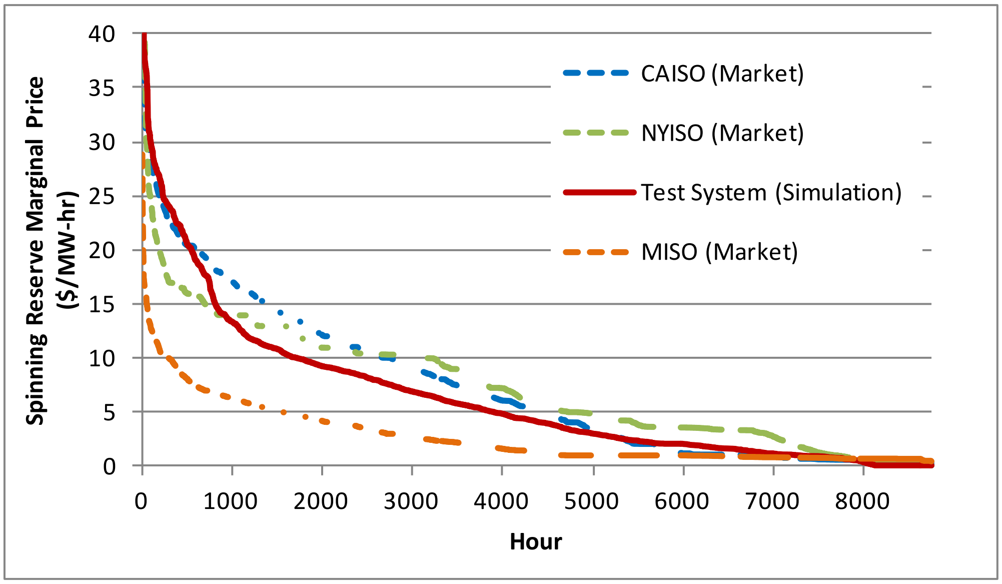

Figure 5-1. Marginal price duration curve for spinning contingency reserves for the base case system (simulated) and three markets (2011 data)

The corresponding curves for regulation reserves are shown in Figure 5-2. In the base system without additional storage, the average price of regulation from the PLEXOS simulations is $16.1/MW-hr.[42] For comparison, the average market clearing price for regulation in 2011 was $11.8/MW-hr in NYISO, $10.8/MW-hr in MISO, and $16.1/MW-hr in CAISO.

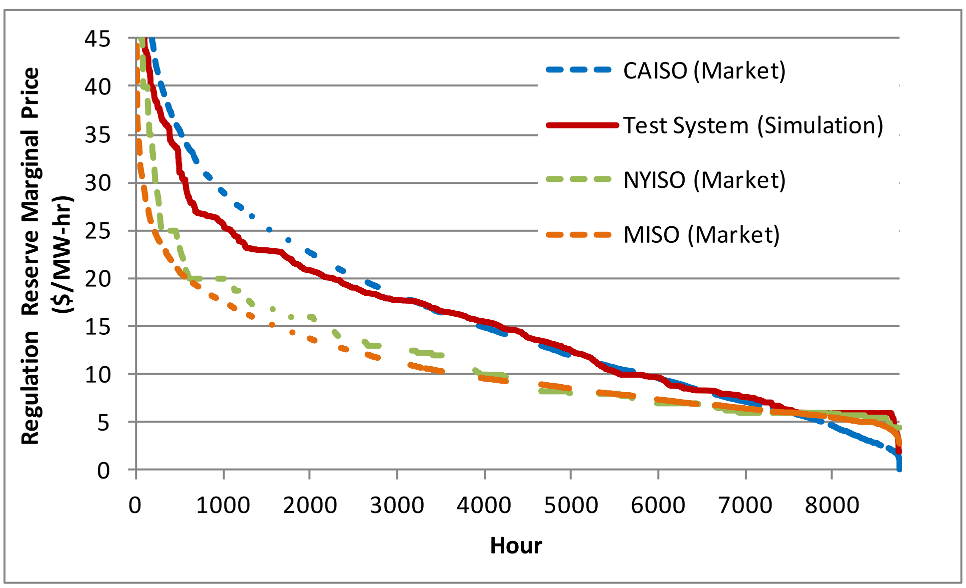

Figure 5-2. System marginal price duration curve for regulation in the base system and three markets (2011 data)

We also evaluated the cost of flexibility reserves. Because this product requires a relatively slow response rate (20 minutes compared to 10 minutes for spinning reserves and 5 minutes for regulation) and can be provided by all generator types, including combustion turbines, we found relatively low values for the cost of this reserve product. As a result, we do not evaluate the value

[42] As with spinning reserves, this excludes 10 hours of extremely high prices driven by internal model penalties.

of storage providing only flexibility reserves in this analysis. However, the actual use of flexibility reserves in real-time dispatch could be of more significant value. Additional analysis of storage performance in sub-hourly dispatch will be required to fully evaluate the potential benefits of this service.

5.2 Base Case Results

As with the energy-only case, we begin by examining a "base" device in detail. The base device size was 100 MW. This is smaller than the energy-only device due to the limited need for reserve services. The largest spinning reserve requirement in either of two simulated balancing areas is only 225 MW, while the regulation requirement ranges between 73 MW and 166 MW, with an average of 120 MW.

Table 5-1 demonstrates the change in generation and fuel use for devices providing only spinning reserves and only regulation reserves. It also compares these cases to an energy-only device of identical capacity (100 MW). As discussed previously, regulation is assumed to be energy neutral; however, energy losses must be considered. This was performed by calculating the product of the hourly energy price, the "regulation energy use ratio" described earlier (assumed to be 25%), and the 20% loss rate (Ellison et al 2012).[43] In Table 5-1 the additional generation and fuel required is listed as "make-up" energy and would actually be derived from thermal units (coal and gas-fired generators).

[43] This efficiency includes constant decay losses.

Table 5-1. Change in Generation and Fuel Use with the Addition of 100 MW of Energy Storage[a]

	Energy Only	Spinning Contingency Only	Regulation Only
Generation (GWh)			
Coal	111	114	180
Hydro	0	0	0
Gas CC	24	-79	-230
Gas CT	-65	-59	14
Other	-10	-3	-7
Existing Pumped Storage	3	-59	-95
Battery	175	0	0
Regulation Make-Up[b]			42
PV	0	0	0
Wind	0	0	0
Total Generation	237	-85	-139
Fuel Use (1,000 MMBtu)			
Coal	1,240	1,151	1,942
Gas	-736	-1,571	-2,214
Regulation Make-Up[c]	0	0	378
Total Fuel	505	-420	106

[a] A positive number indicates an increase while a negative number indicates a decrease relative to the base case.
[b] Make-up energy is real energy that would actually be derived from a mix of coal- and natural-gas-fired generators but was not explicitly tracked in the simulation.
[c] Make-up fuel would actually be derived from a mix of coal and natural gas but was not explicitly tracked in the simulations. The make-up fuel is estimated based on multiplying the total generation by an average heat rate of 9,000 BTU/kWh.

Table 5-1 demonstrates how providing reserves with energy storage increases the overall efficiency of the system dispatch (e.g. by reducing the need for coal units to reduce output to accommodate additional gas-fired generation providing reserves). The overall change in costs is provided in Table 5-2.

Table 5-2. Change in Operational Costs with the Addition of 100 MW of Energy Storage

Cost Component	Change In Operational Cost (Million $) Compared to Case Without Additional Storage		
	Energy Only	Spinning Contingency Only	Regulation Only
Total Fuel Cost	-3.3	-6.8	-8.5
Total O&M Cost	0.3	0.2	0.3
Total Start Cost	-1.5	0.1	0.1
Total Regulation "Adder" Cost	0.0	-0.1	-4.3
Regulation Make-Up Energy Cost[b]	0.0	0.0	1.4
Total Production Cost	-4.4	-6.5	-11.0

[a] A positive number indicates an increase while a negative number indicates a decrease relative to the base case.
[b] Valued derived outside the production simulation.

Table 5-2 demonstrates the significant increase in value associated with providing reserves as opposed to providing load-leveling services. The reserves devices avoid a greater amount of fuel cost by increasing the efficiency of the dispatch. The operational savings associated with provision of regulation reserves is higher than spinning reserves with a large fraction of its value from the avoided regulation cost associated with cycling conventional units.

5.3 Annualized Benefits and Sensitivities

Similar to the energy-only cases, several scenarios were evaluated in the reserves-only cases, summarized in Table 5-3. The base 100-MW device uses the results detailed in Table 5-2. A smaller 50-MW device was also evaluated, showing an increase in value per unit of capacity due to the suppression of reserve prices that occurs with large storage devices. This is particularly important for the regulation device because the 100-MW device provides about 83% of the total regulation requirement. Overall, moving from a 50-MW to a 100-MW regulation device decreases the device system value from $137/kW-yr to $110/kW-yr, and the marginal value of the incremental 50 MW is only about $83/kW-year.

As with energy, the value of a reserves-only storage device in a market setting will likely be lower than the system benefits calculated here due to the uncompensated benefits of reduced starts and the price suppression impacts of energy storage on reserve prices. We calculated the market value of the reserves-only devices by multiplying the hourly reserves price by the reserves provision for all hours. In all cases, these values were less than the system value calculated by taking the difference in production cost. For the 50-MW case, the market value of regulation was $113.4/kW, or about 17% less than the estimated system value, while the market value of spinning reserve was about $51.5/kW-yr, or about 39% less than the estimated system value. Adding another 50 MW has an even greater impact on the value of a regulation device in a market setting. While the marginal system value of the regulation device was estimated at $82.6/kW-yr (as stated previously) the marginal market value of this 50 MW of storage is only about $6.3/kW-yr. Essentially, this additional amount of storage, while providing measureable system benefit, has collapsed the price of regulation and would be unable to capture any of the benefits it provides.

Additional sensitivities to the system value considered in Table 5-3 were the same as those with the energy-only device. Removing the pumped storage plants had a relatively small impact on the value of storage providing reserves, in part due to the restrictions we placed on the pumped storage providing reserves in the base case. Pumped storage was required to be operating at a minimum generation point of 40% while providing contingency reserves and 70% while providing regulation (to ensure symmetric up and down operation.) In addition, we did not allow the pumped storage plant to provide reserves while pumping. As a result, only about 10% of the total regulation reserve requirement in the base case is provided by pumped storage. Removing this existing pumped storage increased the operational value of a reserves-only device by 5%–6%. Increased natural gas price has much larger impact. Overall, these values are significantly higher than the values of the energy-only storage device and can be achieved with a device that stores much less energy (fewer hours of discharge time) based on the market requirements for the corresponding reserve service.

Table 5-3. Sensitivity Cases for the Reserves-Only Devices

	Annual Value ($/kW-yr)	
Scenario	**Spinning Reserves**	**Regulation Reserves**
Base 100-MW Device	65.2	109.8
Reduced Size (50 MW)	83.8	136.9
Remove Existing Pumped Storage	68.3	116.9
Double Natural Gas Prices	148.1	205.4
Remove Existing Pumped Storage and Double Natural Gas Prices	164.8	222.9

Figure 5-3 translates the annual values to equivalent capital costs using the assumptions stated previously, including a range of fixed charge rates.

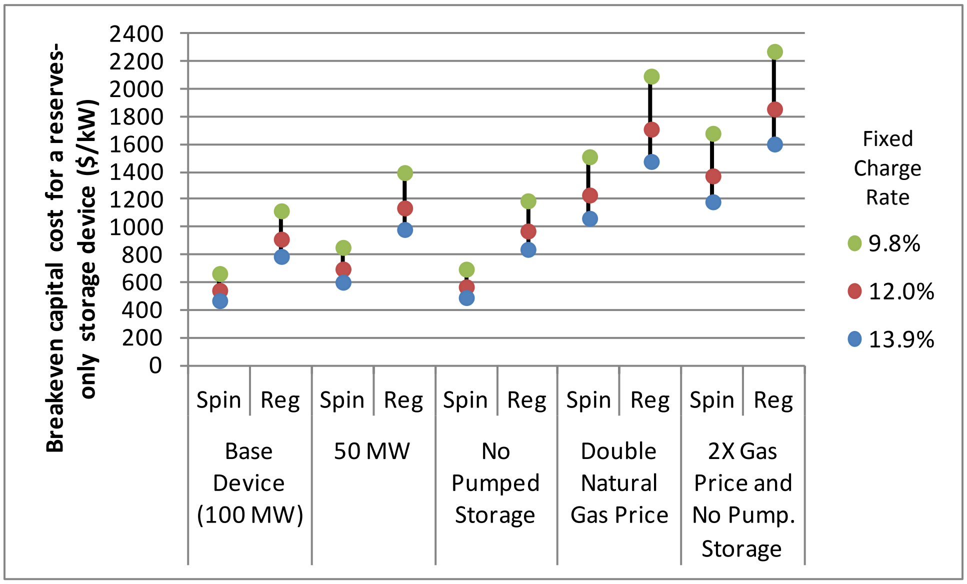

Figure 5-3. Breakeven capital cost of energy storage devices providing only reserves with no capacity value

Because provision of reserves requires physical capacity, a storage device providing only reserves can potentially have capacity value, despite the fact that these devices do not provide capacity in the traditional manner of being able to cover energy demand for an extended period of time. We give these devices a capacity value assuming they will be available to provide reserves during periods of high demand, therefore "freeing up" conventional generators to meet energy requirements (Kirby 2006).[44] As with the energy-only case, this value is only applicable when new physical capacity is needed in the system. Furthermore, the market for these services is much more limited than for energy, and the amount of storage capacity eligible to receive this value cannot exceed the total system requirements for the corresponding reserve product.

[44] The need for physical capacity to provide reserves can also be observed in scarcity prices for ancillary services observed in some markets.

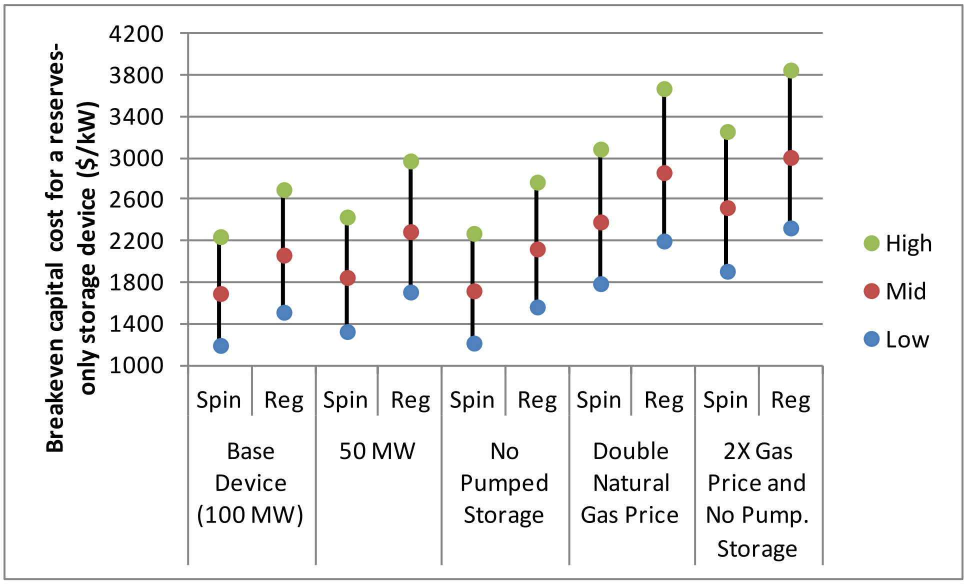

Figure 5-4. Breakeven capital cost of energy storage devices providing reserves and reserves capacity

The capital cost values in Figure 5-4 are substantially higher than those in the energy-only case but still rely on obtaining full capacity benefits. They also require far less energy capacity (as measured by the length of time needed for continuous discharge), and the device providing spinning reserves will experience very little actual operation that might negatively impact lifetime. The regulation device will require more extensive operation, so additional O&M or impacts on device lifetime must be considered when comparing the values in Figure 5-4 to the actual costs of developing and operating a new storage device.

6 Energy and Reserves Results

The final set of cases considered the ability of a long-duration storage device to provide both energy and reserve services.

In theory, the ability of a storage device to be co-optimized allows it to switch between services, depending on which is most valuable at the time. We performed simulations of several 100-MW devices where they could provide energy, spinning reserves, or regulation reserves. Table 5-4 summarizes results for several of the cases where the device is allowed to provide both energy and reserves. The first row of Table 5-4 shows the result for the base device.

Table 5-4. Value of 100-MW Energy and Reserves Devices

	Annual Value ($/kW-yr)	
Scenario	**No Reserves While Charging**	**Reserves While Charging**
Base Case	114.5	127.7
Restricted Flexibility Case (Similar to Pumped Storage)	54.0	63.4

In the simulated system, the additional value of co-optimized operation was limited by the inherently small value of arbitrage opportunities and high value of regulation. Given the option of providing spinning reserve, energy, or regulation, the device provides regulation with about 90% of its capacity on average due to its higher value. Most of the time the on-/off-peak price spread is too small to justify the device providing arbitrage services, and there are very few hours where the arbitrage values exceed the lost regulation revenues. The resulting annual value of $145/kW-yr is only about 4% higher than the regulation-only device. A contributing factor to this small increase in value was the assumption that the storage plant can only provide reserves while discharging and cannot provide reserves while charging for arbitrage purposes. As a result of this assumption, each megawatt-hour of energy discharged for arbitrage foregoes 2.33 MW-hr of lost regulation sales (1 MW-hr during the discharge process and 1.33 MW-hr while charging, with the extra 0.33 MW-hr of lost capacity due to storage losses.)

There could be additional opportunities to provide reserves while charging, and a completely flexible device could actually provide twice its rated capacity in up reserves during periods of charging. We evaluated the impact of this constraint by allowing a device to provide spinning and regulation reserves while charging. This increased the fraction of the time the device provides energy services, and the resulting annual value increased by 12% to about $128/kW-yr. This type of operation will require additional analysis to consider various energy constraints when providing multiple services.

Finally, we considered the impact of adding additional constraints on storage device flexibility. This device has operation constraints similar to a pumped storage plant, including a minimum generation point of 40%. We also assume that the provision of regulation reserves requires the plant to be generating at 70% or greater output to provide symmetric output. This set of restrictions limits the ability of the plant to provide reserves, and the resulting value is substantially less than the more flexible device. In the case where the plant cannot provide reserves while pumping, the total value is about half of the more flexible device at about

$54.0/kW-yr. The ability of a pumped storage plant to provide reserves while pumping depends on installed equipment. We evaluated a conservative case where the plant is able to provide only spinning reserves while charging and found this increased its value by about 17% to $63/kW-yr. A forthcoming study will further analyze the ability of advanced pumped storage plants to provide multiple grid services and associated value (Kirby et al. forthcoming).

7 Conclusions and Future Analysis Requirements

We examine the value of an energy storage device as the sum of its operational and capacity values. The operational value is highly dependent on the service provided. We considered three services both individually and when combined. Analysis of the value of energy storage using a production simulation follows several trends of previous analyses, including the fact that regulation reserves has higher value than spinning reserves, which itself has higher value than load-leveling (arbitrage) services. The reserve services also have the advantage of requiring less stored energy (fewer hours of discharge capacity) in the storage device. However, the higher value service also has a much smaller market potential due to the lower need for reserves capacity compared to energy capacity. The operational value of storage in this study is also inherently limited by the low natural gas prices in the base system. Overall, the value of energy storage is largely dependent on it obtaining a capacity value, even if the device is providing higher-value reserve services.

Economic deployment of energy storage is further challenged by its potentially limited ability to obtain the full value of services provided to the system. In areas with restructured markets, storage might only be valued by the system marginal energy price and not be compensated for its ability to reduce thermal plant starts. Furthermore, as a storage device buys and sells energy it can increase system efficiency and reduce the overall cost of generation but will itself affect the marginal price of energy reducing its own compensation and not benefit from this reduction in energy costs to consumers.

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. One of the most significant needs is to better understand the impact of increased renewable penetration, along with the impact of storage plant operation at shorter timescales. 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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