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Evaluating Utility Owned Electric Energy Storage Systems: A Perspective for State Electric Utility Regulators

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Abstract

This report provides a perspective on issues pertaining to the deployment of utility owned electrical energy storage. The intended audience includes state electric utility regulatory authorities, their staffs and the planning personnel in the utilities they regulate. Its purpose is to inform the audience about the potential opportunities for energy storage technologies to play a greater role in the evolving electricity marketplace and grid. The surge of investments in renewable energy (RE) during the last decade, particularly wind and solar energy has stimulated interest in energy storage. These technologies have the capability to balance the variability inherent in many RE technologies. The state public utility commissions' (PUC) responsibility for regulating utilities leads to a focus on aspects of grid operations and expansion including: voltage and frequency regulation; distributed generation; renewable energy, particularly the administration of Renewable Portfolio Standards (RPS) mandates; and grid capital investment. Energy storage systems can contribute in each of these areas. Given the potential of energy storage technologies to perform these functions, their access to the regulatory process must be improved together with removal of barriers and appropriate and consistent cost benefit analysis methodologies so that they are routinely included in the suite of options considered for providing key grid services. The solutions that deliver the services cost effectively will likely be the solutions put forth by utilities and approved by utility commissions. Two storage system case studies are presented as a means to illustrate some of the fundamental valuation principles particularly pertinent to energy storage systems.

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Acronyms

AC	alternating current
A-CAES	adiabatic CAES
BPU	Board of Public Utilities
CAES	compressed air energy storage
CPP	critical peak pricing
CT	combustion turbine, usually simple cycle (Brayton cycle)
DC	direct current
DER	distributed energy resource
DG	distributed generation
DOE	Department of Energy
DR	demand response
EV	electric vehicles
EES	electric energy storage
ESS	energy storage systems
FERC	Federal Energy Regulatory Commission
GT&D	generation, transmission and distribution
GW	gigawatt (1,000,000,000 watts)
GWh	gigawatt hour (1,000,000,000 watt-hours)
HEV	hybrid electric vehicles
ILR	interruptible load for reliability
IOU	investor-owned utility
IRR	internal rate of return
kW	kilowatt (1,000 watts)
kWh	kilowatt-hour (1,000 watt-hours)
LMP	locational marginal price
LESR	limited energy storage resource
MW	megawatt (1,000,000 watts)
MWh	megawatt hour
NERC	North American Electric Reliability Corporation
NOI	Notice of inquiry
NOPR	Notice of Proposed Ruling (FERC)
PHEV	plug-in hybrid electric vehicles

PPA	power purchase agreement
PQ	power quality
PSC	Public Service Commission
PUC	Public Utilities Commission
PV	photovoltaic
RE	renewable energy
RFI	request for information
RFP	request for proposal
SMES	superconducting magnetic energy storage
SNL	Sandia National Laboratories
T&D	transmission and distribution
TES	thermal energy storage
TOU	time-of-use (usually TOU electricity rate)
UPS	uninterruptable power supply

Executive Summary

This report presents what the authors hope the reader will regard as a fresh perspective on electrical energy storage resources. This perspective is for use in the state utility regulatory environment wherein regulatory commissions may soon be faced with the need to evaluate requests for recovery of investments in electrical energy storage devices.

Reliance is placed on the substantial quantity of recent descriptive presentations of the technologies considered as electrical energy storage (EES) systems, results of engineering research and development, and analysis of the economics of acquisition and operation of EES in both market and state-regulated environments. Many of the engineering and economic presentations have attempted to gauge the relative economics of these systems and present ―generic" assessments. As is characteristic of emerging technologies, EES systems have a challenge to present a strong business case in comparison with competing devices, such as generation, transmission, demand response and other technologies that can provide similar services, in use on the grid. While a wide array of potential benefits are attributed to energy storage devices, other technologies can also provide these services leaving the relative economics as a deciding criterion. With ongoing research, costs for energy storage technologies are likely to decrease in the near future, and with increasing renewables penetration, their value should increase, leading to an improved economic case. Thus, energy storage systems may be on the cusp of emerging from a period of uncertainty and marginal economics to providing available capacity and energy economically. Major companies are making proposals to invest in large, MW-sized projects to provide reserves.[1] With some speculation, a deployment strategy of focusing on a few (one in the case cited) revenue streams can be inferred from this development.

This report presents an overview of grid-scale electrical energy storage technologies, those deployed at a scale appropriate for providing transmission or distribution grid service as opposed to those providing behind the customer meter service. Energy storage technologies are defined and factors affecting the current and future demand for grid storage are identified and discussed. Though energy storage demonstration projects increase experience and knowledge of energy storage systems and can validate their performance capabilities, in regulated environments storage systems must prove to be economically competitive. Thus, this report presents little discussion of these demonstration projects.

The status of the state regulated utility environment for energy storage system deployment is discussed to provide state utility regulators an understanding of how energy storage systems can be considered an electric grid asset. A significant contribution of this report is a review of many of the state utility commission dockets under active or closed adjudication in various jurisdictions around the United States. From this review, we have extracted the key concerns and challenges that utilities, interveners, and commission officials have raised with respect to storage:

- Operational definition and classification– EES defies classification as a generation, transmission, or distribution asset;
- Challenges to quantifying value, which leads to difficulty in proving cost-effectiveness; attribution of multiple benefits complicates valuation;
- Limited operational experience (such as, controls interoperability and grid interconnection) leads to uncertainty regarding value contribution of benefits; Institutional inertia inhibits learning-by-doing;
- Uncertainty regarding jurisdiction of FERC and State PUCs over storage;

[1] See: ―Newsday: 400 megawatt battery proposed for LIPA." AES Energy Storage. http://www.aesenergystorage.com/news/newsday-400-megawatt-battery-proposed-lipa.html

- Mandates and incentives might encourage more deployment but interrupt the process of market valuation of the technologies.

Each of these issues is discussed and possible means to resolve the issues and concerns presented.

A significant portion of the report is also devoted to identifying and discussing the methods for evaluating energy storage devices. Several options range in time and resource costs. A suggested approach and methodology to evaluate the economics of energy storage devices follows. Two detailed case studies present, discuss, and apply the valuation method.

Much of the literature about energy storage systems has sought to portray them as unique and endowed with a wide array of potential benefits. This report has attempted to cut through some of this complexity in order to emphasize the essence of energy storage systems. It should help to make the valuation of energy storage systems more straightforward from a technological, economic, and regulatory standpoint.

The one feature that makes these systems unique—their ability to store energy— also puts them in direct economic competition with load, or more properly, demand response. Not only do storage technologies face competition from every technology on the supply side but also competition from those on the demand side. Thus, the main present challenges to increased deployment have to do with economic comparisons—can energy storage systems deliver their services at lower cost than competing technologies? Public utility commissioners faced with decisions regarding such technology deployments will ultimately make their decisions based on protecting the interests of their constituents: do these technologies help to protect electricity consumers from unnecessary increases in electric rates?

Trends in the industry may help to further the deployment of energy storage systems. Clearly increased penetration of renewables is one such trend. The increased —peakiness” of load and declining inertia on the system may also provide opportunities. Furthermore, the relatively small scale of most energy storage technologies (pumped hydro and CAES excepted) should provide increased opportunities for deployment. A deployment strategy emphasizing the appropriate technology and scale to provide distribution system and near-to-consumer deployment can be cost-effective, and provide grid support indirectly, while at the same time, buy time for further (cost-reducing) technology development of larger energy storage technologies.

The following are among the most important takeaways from this analysis:

- Electric Energy Storage systems (EES) have the potential to play a major role in the current and future electricity grid;
- EES systems have a unique feature in their ability to store energy; they are also able to change their energy output extremely rapidly as compared with conventional generators;
- The value contributed by EES is judged by the cost of the next best alternative means of providing the service;
- Vertically integrated utilities may have an advantage in their ability to internalize all of the benefits available from energy storage technologies. This cannot be conclusively demonstrated and may depend on organizational structure and other business characteristics. Unfortunately, these benefits are valued at cost (of the next best alternative) as opposed to being based on revenues derived from market transactions as they would be in a market environment;
- Asset classification issues can be clarified by viewing the systems from the point of view of the services they perform, rather than their inherent engineering characteristics;
- The regulatory environment may make it difficult for utilities to propose such systems; regulatory commissions may need to work with utilities to facilitate deployment; establishing a framework

for evaluating EES services, as provided in this report, may help increase deployment by aiding utilities in proposing, and regulatory commissions in evaluating, energy storage systems;
- Phase-in tariffs or other incentives might provide the necessary financial boost to induce utilities to invest in EES in the absence of carbon pricing.

The Appendix discusses pertinent engineering and physical characteristics of energy storage devices. It also presents the detailed benefit-cost evaluation of the selected ESS case studies.

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1 Introduction and Plan of the Report

1.1 Introduction

This report provides a perspective on issues pertaining to the deployment of utility owned electrical energy storage (EES) for state electric utility regulatory authorities, their staffs and planning personnel within the utilities they regulate.[2] Its purpose is to inform this audience about the potential opportunities for energy storage technologies to play a greater role in the evolving electricity marketplace and electricity grid.[3]

The surge of investments in renewable energy (RE) during the last decade, particularly wind and solar has stimulated renewed interest in energy storage and the role it can play in managing the electricity transmission grid. Energy storage has the capability to mitigate the inherent variability of RE technologies. It can also provide a variety of different grid services. Given the potential of energy storage technologies to perform these functions, their access to the regulatory process can be improved so that they are routinely included in the suite of options considered for providing necessary grid services.

1.2 Organization of the Report

The report is organized as follows: Section 2 introduces utility owned electric energy storage, functional uses (applications), factors affecting demand or load, and factors affecting future grid development. An extensive review of the extant rate base requests currently or previously active in the U.S in Section 3 follows. Identified from this review are key issues and concerns raised by utility personnel, state regulators, and interveners. Section 4 outlines the key elements of an ―ideal" rate base investment recovery request. Section 5 presents concluding observations. An appendix describes energy storage technologies in more detail to provide the reader with essential information to understand the technologies, their features and functional uses, and two case studies implementing the analysis process presented in section 4.

1.3 Related Sandia Energy Storage Guidebooks and Reports

Sandia will publish three energy storage guidebooks in 2012. These are:

1) This regulatory handbook: This handbook is intended for the state regulatory audience across the United States, particularly in those states that have limited or no experience with energy storage technologies.

2) DOE/EPRI 2012 Electricity Storage Handbook in collaboration with NRECA: This handbook is intended for utilities and system developers. It provides a comprehensive discussion of energy storage technologies, a cost database of these technologies, a discussion of the regulatory and market environments, installation and deployment processes for energy storage systems and supporting documentation including sample requests for proposals (RFPs) for storage systems and sample power purchase agreements.

[2] The topic of this paper relates to devices that utilities (load serving entities, distribution utilities, and transmission utilities) would install on their grid. Many storage devices are placed on the consumers' side of the meter often for power quality reasons. These devices, while extremely effective, are outside the scope of this effort.

[3] We use the acronym EES to refer to electric energy storage as differentiated from natural gas and pumped hydroelectric, both excluded from consideration in this report. Electrical energy storage (EES), energy storage, and storage technologies will be used interchangeably. Each of these refers to electrical energy storage technologies or systems.

3) Methodology to Determine the Technical Performance and Value Proposition for Grid-Scale Energy Storage Systems: This report is intended for utilities, developers, and manufacturers to help guide a performance and economic evaluation process for the ARRA (American Reinvestment and Recovery Act) funded energy storage projects.[4] The evaluation processes presented is applicable for utilities, developers, and regulators when considering other installations in both market and non-market territories.

Sandia intends each of these guidebooks for different audiences, but as a whole, they provide a comprehensive overview of the energy storage landscape from the perspectives of regulators, utilities, developers, and manufactures. Users of these guidebooks should focus their intention on the directly applicable report, but keep in mind that the others have information that may provide further insight into the tools and processes that are useful in evaluating these technologies from an economic and performance perspective, the regulatory and market environments that users of the technologies will navigate and a comprehensive overview of technology capabilities and characteristics. Sandia intends these reports to provide energy storage a fair consideration and evaluation relative to alternative technologies when power system stakeholders address grid requirements.

[4] See http://www.sandia.gov/ess/projects_home.html.

2 Utility Owned Electric Energy Storage (EES)

2.1 Energy Storage Sources

Energy storage systems that produce useful work have been utilized for millennia. Dams and diversions of river courses to create hydraulic head for mechanical energy production have been in use for thousands of years (Tiwari & Ghosal, 2005, p. 285). Modern hydro facilities now produce electricity as well as other benefits.

Conventional hydroelectricity (CH) and pumped storage hydroelectricity (PSH) represented about 5.9% of the 2008 net generation of electricity produced within the contiguous forty-eight states. In terms of net summer installed generation capacity, hydroelectric facilities comprise about 9.9%.[5] (Loose, 2011)

The North American electricity grid, like all other electricity grids, has been built to meet peak load, which is typically spread over a few hours in the early morning and the early evening during the peak seasons. Peak seasons in North America are typically either summer or winter depending on a location's latitude. During all other hours of the day, this unused capacity can be viewed as a form of storage (NRRI, 2011).[6] Leveling the load over the daily and seasonal cycle remains an opportunity to reduce system costs. Recessions in the late 1990s and from 2007 to 2010 interrupted growth in electricity demand, thereby adding to reserve capacity.

Related to the opportunity to shift load from on-peak to off-peak is the opportunity to utilize near-to-real-time demand response to compensate consumers who can adjust their electricity use in response to price signals. This can be seen as yet another form of storage. Mechanisms to implement this type of market participation through retail choice are available in some locations around the country. However, generally speaking, the plans have not, to date, been as enthusiastically received as hoped. Retail choice is likely to be a significant component of balancing demand and supply but consumer friendly technologies, such as technologies in Smart Grid programs, will be instrumental in providing consumers the information needed to adjust consumption patterns.

2.2 Energy Storage Technologies Defined

Energy storage systems do not store electricity directly, but rather convert it to another form of energy that is then stored (kinetic, electrochemical, electrostatic, potential, etc.) and when electricity is needed or is more valuable, reconvert it back. Thus, energy storage systems have the unique capability to be both consumers of electricity (during the charging phase) and producers of electricity (during the discharging phase).

At present, uses of electrical energy storage (EES) in the utility industry have been limited. Utility-scale EES projects based on storage technologies other than pumped hydroelectric storage have been utilized, though they have not become common. Existing U.S. facilities include one compressed air energy storage (CAES) system, several plants based on lead-acid batteries, a few based on sodium sulfur and lithium-ion batteries and one based on nickel-cadmium batteries. Additionally, one utility scale flywheel facility is in operation and others are planned or in construction. In all, roughly 2.5% of the total electric power

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[5] *Capacity is defined by the U.S. Energy Information Administration as "the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions.* See: *EIA. (2012). Glossary Retrieved February 1, 2012, from http://www.eia.gov/tools/glossary/index.cfm?id=G#gen_cap*

[6] Sherman Elliott, Commissioner in the Illinois Commerce Commission makes this point.

delivered in the United States passes through energy storage, largely pumped hydroelectric facilities. The percentages are larger in Europe and Japan, at 10% and 15%, respectively (EPRI 2003).[7]

The most commonly discussed EES technologies have been grouped into electrochemical and non-electrochemical categories. The former includes the more common lead acid and sodium-sulfur batteries as well as battery technologies such as nickel cadmium, nickel metal hydride, lithium ion, and flow batteries. Non-electrochemical EES technologies include pumped storage hydroelectric, compressed air energy storage, and flywheels.

Many papers and reports describe each of the EES technologies in detail. Examples include Sandia (2003, 2005, 2008, and 2010), EPRI (2003, 2004, 2005, and 2010), Gyuk, et al (2005), among others.

A complete list generally includes superconducting magnetic energy storage and thermal energy storage. Superconducting magnetic energy storage is currently too expensive to be considered at the grid level. Thermal energy storage has significant potential for deployment, as some forms, such as electric water heaters, are commercial level systems. However, they are largely customer level resources (behind the meter and distributed). Ice storage is another such technology and has been discussed in a PUC case, but again is generally considered a customer side technology.[8] These distrusted technologies can be controlled in aggregate to provide grid-scale bulk services, though this action falls under the purview of demand response technologies and out of the scope of this report.

There are also examples of grid level thermal storage technologies. One is a combined heat and power district cooling system in Austin, TX, but it does not provide typical system services, and again could be considered a form of demand response.[9] Solar thermal with molten salt as the storage medium is another grid-scale thermal storage technology. However, it is specific to a single solar thermal generation unit and thus is integrated into a solar thermal plant. It would not be discussed as a separate entity from the solar thermal plant and is thus not discussed here.

2.3 Grid Uses for Storage Technologies

In general, the grid uses to which energy storage technologies can be applied or the services they can supply to the grid are identical to those of any generator technology. Thus, energy storage systems have many similarities to the equipment currently found on the electricity grid. The truly unique feature of EES systems is their capability (or necessity) to absorb energy at times when it is desirable from a system or cost perspective. EES systems are the only systems that have this inherent capability to supply and absorb energy. Thus, these systems have the capability to provide capacity, energy, load, and fast ramping to the grid. Their limitation, however, is that they can only provide these grid services for a limited duration determined by the amount of stored energy available and thus are ―limited energy storage resources" (LESRs).

All of the applications discussed by Eyer and Corey for example, can be performed by any generator and are not services that ESS systems can uniquely supply (Eyer & Corey, 2010). Thus, whether a utility or grid operator employs energy storage systems depends at least partly, perhaps predominantly, upon the relative economics of energy storage systems versus the alternative technologies that could provide the

[7] See Ch. 30 in *Reddy, T. B., & Linden, D. (2011). Linden's handbook of batteries (4th ed.). New York: McGraw-Hill.*

[8] Discussed in the New Jersey Central Power & Light demand response filing before the New Jersey Board of Public Utilities. (NJBPU, 2008)

[9] See Austin Energy. ―District Cooling Services." http://www.austinenergy.com/Commercial/Other%20Services/On-Site%20Energy%20Systems/districtcooling.htm

same services. Advocates for storage technologies frequently make the case for the technologies, partly based on the wide range of potential applications (often referred to as benefits) and the degree to which energy storage can provide solutions to emerging concerns in the evolution of the grid.

A potential advantage for energy storage technologies, particularly batteries and flywheels, is that they are modular and have the potential to be scaled more appropriately to the use. However, this advantage comes at a cost, as the capital cost per installed kW may be higher due to the smaller scale. Additionally, storage technologies may have an advantage in the effort to reduce emissions of air pollutants from electricity generation, as high emission peaking gas power plant use, as well as the amount of generator ramping, can be reduced. However, the observation can be made that EES generally would be charged using a mixture of fossil fuel generators –serving the grid. This would therefore embed some average level of emissions in the electricity stored. That said, energy storage that is co-located with wind energy or solar farms would be charged using emission-free energy if located on the same side of the meter.

2.4 Factors Affecting Demand for EES

The present state of the U.S. economy affects the overall performance of the electricity industry, which is operating well below capacity in line with much of the rest of the economy. It appears that this condition may persist for several years. With excess capacity currently on the system and financial returns to its operation reduced, electricity asset owners are not motivated to increase capacity. The hope is this condition will eventually correct itself and the U.S. economy will get back to business as usual, making a more attractive climate for new capacity investment.

2.4.1 Transmission Constraints and Congestion

The electric transmission infrastructure faces increased challenges. Disagreements about which entities should own and/or pay for new transmission capacity and growing resistance to the siting of new transmission infrastructure for environmental and aesthetic reasons are among the issues.

EES systems provide an alternative to building new lines. Storage can be used to increase throughput of existing transmission capacity by reducing congestion and offsetting unhelpful electrical effects, and can reduce the need for new transmission capacity through a constrained portion of the transmission system. This requires that the storage device be located downstream from transmission constraints and that it be charged at night when the transmission system is not heavily loaded. Using storage, more electricity can be transmitted using the same infrastructure and the need for additional transmission capacity is reduced. Outside of congestion and capacity issues, energy storage can also play a role in deferring transmission upgrades for system stability purposes. For example, it may provide voltage support or a fix for an unreliable transmission interconnection.

2.4.2 Increasing Variable Renewable Energy Generation

Variable renewable energy resources, predominantly wind and solar, are expected to provide a growing portion of new capacity additions in the electric industry. EES systems are widely valued as important enablers of variable renewable generation. The nature of variable renewable generation, particularly wind, is such that EES systems can be charged with off-peak (low price) electricity from RE generation so the stored EES energy can be used during peak demand when it has greater value. EES with rapid, accurate response can also offset short-term output variations from wind turbines and passing clouds that affect solar generation. In addition, EES may enable the reduction in size of interconnection facilities and T&D network upgrades required to interconnect wind and solar systems to the grid.

2.4.3 Operational Advantages of EES

EES systems are unique in that they can be useful both in the typical daily and diurnal energy cycles of peak and off-peak. During peak periods charged EES can provide imbalance energy and ancillary services that help moderate peaks. During off-peak periods, they could absorb energy from the system. These features can prevent the operationally expensive cycling of plants and curtailment of wind and solar generation and thereby improve overall system performance.

2.4.4 Cost-reducing Technology Development for EES

Increasing development of advanced energy storage technologies – primarily of *modular* technologies – follows from advances in materials science, nanotechnology, power electronics, communication and control, and manufacturing, which combine to bring down cost. Deployment of EES, particularly in rapidly expanding areas of Asia and Europe, will expand information and experience with EES technologies, thus lowering costs. The increasing manufacturing volume of electric vehicles (EVs) and partial hybrid electric vehicles (PHEVs) is also expected to have a beneficial effect on the stationary energy storage market by driving down the cost of the battery component of a Li-based EES.

2.4.5 Environmental Advantages of EES

At present conventional generators (coal and natural gas) provide most of the reserve capability needed by the grid. These units perform this service by operating below their optimal operating points and cycling to meet reserve requirements, which results in less efficient operation using more fuel and creating more emissions. If a greater portion of reserves were to be provided by EES, the conventional generators on the system could operate more efficiently, allowing them to provide energy instead of reserve capacity, leading to the system being operated in a more environmentally friendly manner. If the EES system were charged using renewables, there would be a further reduction in emissions as no emissions would be generated to meet reserve requirements.

2.5 Factors Affecting the Future Grid

A number of long-term trends affecting grid stability and reliability have been identified as issues or causes for concern that may need to be addressed. These are notable because energy storage technologies have been advanced as possible solutions to these emerging issues:

- The existing grid and its control and protection features are designed to work with the mechanical inertia inherently present in rotating, turbine-driven or engine-driven generators known commonly as conventional generators. A change in the operating practices of conventional generators, such as an increase in the use of variable resources, can cause a decline in the frequency response of the grid. This, together with increasing investment in newer, non-traditional, generating resources, is characterized by “inertia-less” power generation. Increasing penetration of such sources decreases grid inertia, which then results in more difficult frequency control for grid operators who have fewer inertia sources to provide this essential grid resource. It has been shown that the presence of fast-acting energy storage can assist the grid operator by providing a compensating resource as grid inertia decreases.[10]

- The increase of generation capacity in variable generation technologies (renewable energy) in terms of both nominal capacity and percentage of total capacity is a factor. This change raises issues of stability and reliability for the grid and may increase the requirements for regulation reserves to mitigate variability. Thus, it may offer opportunities for new technologies to be developed to integrate these variable resources. There may also be opportunities for new control technologies that mitigate additional reserve requirements: new control designs tailored to the distinct dynamic characteristics and capabilities of renewables may be available that avoid the current design philosophies that seek to make variable generation mimic the control behavior of traditional synchronous generators (DeMarco, Baone, Han, & Lesieutre, 2012). Such new controls could have the effect of reducing the quantity of additional reserves that would otherwise be required.
- The lack of sufficient investment in the transmission network and the resultant transmission congestion and constraints present issues for the grid: the focus of the industry for at least the last two decades has been on the potential for and realization of industry restructuring, raising first the contentious issue of “stranded assets” that might result from the evolution of markets and then implementation of efficient wholesale markets. One major and minor economic downturn also occurred during this period, greatly affecting the financing climate for investments in the grid. The result has been that less attention was focused on the requirements to maintain and upgrade the transmission grid. Thus, the need still exists to upgrade critical points in the transmission network in addition to the increasing necessity for transmission capacity to deliver renewable energy from remote wind and solar installations.

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[10] See, for example:

Kirby, B. “Frequency Response Concerns & Renewable Generation.” Presentation to FERC staff Conference, September 23, 2010. Available at: http://www.ferc.gov/eventcalendar/Files/20100923090211-Kirby,%20AWEA.pdf.

Miller, N., K. Clark, M. Shao. “Impact of Frequency Responsive Wind Plant Controls on Grid Performance.” December 20, 2010. Available at: http://www.nrel.gov/wind/systemsintegration/pdfs/2011/active_power_control_workshop/miller.pdf

North American Electric Reliability Council. “Frequency Response Standard Whitepaper. April 6, 2004. Available at : http://www.nerc.com/docs/oc/rs/Frequency_Response_White_Paper.pdf

2.6 Privately Owned EES for Regulated Utilities

A regulated utility could procure energy storage services by another mechanism: power purchase agreements (PPAs). There are a number of energy storage developers currently pursuing a strategy of owning EES systems and selling power system services into market environments. Regulated utilities may be interested in such a model where they do not have to own this potentially risky capital, and yet can obtain the services they offer. This mechanism is a means through which many utilities in regulated regions procure renewable energy into their system to meet state RPS requirements.[11]

However, it is important to remember that other technologies are able to provide similar services. Unless there is a specific need for the characteristics of energy storage that an alternative technology might be unable to provide, a developer would have to compete against other developers in a competitive bidding process to provide services at the lowest cost. This would be the mandate of the public utility commission in approving any such power purchase agreement. As of the publication date of this report, the authors are aware of no such instances of a regulated utility procuring service solely through an energy storage system by means of a PPA.[12]

In the case of renewable energy installations, there has often been a state mandate (renewable performance standard) requiring utilities to procure renewable energy resources. Such is not the case for energy storage systems. In the case of traditional thermal generation, namely gas-fired generation, it may be the cost-effective mechanism to procure service and is thus why a utility would enter such an agreement. This is not to say that developers could not provide competing price points to traditional resources. Energy storage systems have the potential to be the cost-effective option especially when providing multiple services. In this situation, a PPA may be a mechanism by which a utility could avoid risk.

It is important that utilities make a consideration of energy storage systems either as rate base assets or through external procurement within their resource planning processes. Regulators may want to ensure that utilities consider energy storage systems in their portfolio of options when proposing new resources. The current structure through which utilities externally procure the services of renewable and traditional resources is transferable to energy storage systems and as long as proper consideration is given, energy storage systems should be the resource of choice if proven cost effective.[13]

The remainder of this report focuses on rate base consideration of energy storage assets. Nonetheless, a lot of the information and processes discussed translate to an evaluation of PPA procurement of energy storage services.

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[11] See PG&E. http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/

[12] In the case of Hawaii, there are energy storage systems tied to wind and solar installations in which services are sold under a PPA with Hawaii's regulated utilities.

[13] The *2012 Energy Storage Handbook* cited previously contains further detail on third party PPAs as a means to procure energy storage services including sample PPA agreements.

3 Review of Current and Recent PUC Dockets Involving EES

Prospects for energy storage are promising with benefits that can be significant and varied; yet, notable challenges exist, inhibiting increased storage deployment. Though a brief summary does not capture the breadth of the challenges, some of the more notable challenges are mentioned here.

Current regulatory frameworks (conceived and developed many decades ago) induce utility incentives, practices, and biases that tend towards conservative decision-making and limited experimentation with new resources. Furthermore, utility system planners and engineers may not have the necessary standards, practices, and tools needed to appropriately evaluate and design storage systems.

Before utility planners and engineers can specify investments in energy storage systems, they need to know what information and evidence regulators require in order to approve utility ownership and rate base recovery. Given that many types of energy storage are new and/or unproven, more operational experience is needed before those newer technologies will be readily accepted. Demonstration projects are an avenue towards developing this experience, and while they can prove performance capabilities, there are still issues related to longevity of the system and economics.

Price signals do not exist for some storage benefits and the magnitude of other benefits is yet to be verified. In addition, storage benefits vary according to stakeholders with different agendas, identifying a need for collaboration and coordination among these stakeholders. This coordination may be expensive or impractical. To delve further into these issues, the authors reviewed the extant public hearing records available across the United States. Results of the review are summarized below. The authors' observations and comments are provided after each section.

3.1 Synopsis of Investment Recovery Requests

This is a review of investment recovery cases, or project approval cases, wherein regulated utilities have filed requests related to energy storage technology investments with public hearings held before state public utility commissions around the United States. This is not a comprehensive review in that the cases selected are only those that have had procedural debate on energy storage proposals. Other cases with storage system proposals exist but without any procedural debate addressing energy storage. This review presents and discusses the issues raised by public utility commissions (PUCs), regulated utilities, storage owners, and other interested parties (or interveners) on the energy storage system proposals and the challenges these issues present to storage system deployment.

3.1.1 Synopsis of Cases Involving Requests for Investment Recovery through Rate-Base Addition

The investment recovery cases summarized below are presented by state. Many of these cases have been brought forward as a pilot or demonstration project. Exceptions include the sodium sulfur battery in Texas, the pumped hydroelectric proposal by PG&E, the Overall Rate Case for 2012 by SDG&E, and the California rulemaking hearing on *AB2514*. Thus, when evaluating these cases, keep in mind the potential differences in approval criteria between full-scale (actual) projects and demonstration projects. While many concerns mentioned in these cases would be relevant to a full-scale deployment request, final decisions often cited the demonstration aspect as an issue to overcome or justify deficiencies in the proposals. Nonetheless, the issues discussed in these cases have been grouped categories by topic. Commentary and suggestions are provided as to how these issues were dealt with and can be approached in future rate recovery hearings.

Texas

Case: Presidio, TX Sodium Sulfur Battery Installation (ETT, 2008)
Applicant: *Electric Transmission Texas (ETT)*
Summary: A case filed for regulatory approval and transmission cost of service recovery for the installation of a Sodium Sulfur Battery System (4.8 MW) in Presidio, TX. The purpose of the system is to ensure the reliability of electricity in the remote town that has a long history of outages and to defer new transmission investment.
Case Status: *Approved April 2009*
Project Status: *In Operation as of April 2010*

California

Case: San Diego Gas & Electric Overall Rate Case (Smart Grid Section) (CAPUC, 2010b)
Applicant: *San Diego Gas and Electric (SDG&E)*
Summary: A case requesting the establishment of rate recovery for SDG&E starting January 1, 2012. The smart grid section implements new smart grid infrastructure including energy storage to help SDG&E meet the California Renewable Portfolio Standard.
Case Status: *In Progress*

Case: Pumped Storage Project Study (CAPUC, 2010a)
Applicant: *Pacific Gas & Electric (PG&E)*
Summary: A request to obtain rate recovery for a feasibility study for a new pumped storage project. The purpose of the project is to allow PG&E to fulfill its perceived need for pumped energy storage by 2020. The expectation of necessity is based on California's renewable performance standards through 2030 that result in a large amount of variable renewable energy capacity additions to the grid.
Case Status: *Denied:* September 2011

Case: Compressed Air Energy Storage Proposal (CAPUC, 2009)
Applicant: *Pacific Gas & Electric (PG&E)*
Summary: A request for Commission approval to provide the balance of matching funds to support a federal grant of $24.9 million from the US Department of Energy (DOE) for a Smart Grid Compressed Air Energy Storage (CAES) demonstration project, authorized by the America Recovery and Reinvestment Act of 2009 (ARRA).
Case Status: *Approved:* January 2010
Project Status: *In the planning and design phase.*

Case: Southern California Edison Tehachapi Wind Storage Project *as part of California's Smart Grid Rule Making Process (CAPUC, 2008)*
Applicant: *Southern California Edison (SCE)*
Summary: Southern California Edison Company (SCE) requested approval to recover up to $25,978,264 for SCE's cost share in the Tehachapi Wind Energy Storage Project (TSP). This cost share will be matched by $24,978,264 in Federal stimulus funding awarded by the United States Department of Energy (US DOE) under the American Recovery and Reinvestment Act of 2009 (ARRA). The project is a lithium-ion battery (8 MW/32 MWh).
Case Status: *Approved:* July 2010
Project Status: *Projected to be in operation by December 2012*

Case: California Rule Making for Energy Storage *AB2514 (CAPUC, 2010c)*
Summary: A rulemaking in response to the enactment of legislation *AB2514* (Skinner, 2009). The legislation directs the CA PUC to open a proceeding to determine appropriate targets to procure viable and cost-effective energy storage systems and, by October 1, 2013, to adopt an energy storage system procurement target, if determined to be appropriate. The CA PUC has also opened this proceeding to initiate policy for California utilities to consider the procurement of energy storage systems.
Case Status: *In Progress*

New Jersey

Case: Proposal for Four Small Scale/Pilot Demand Response Programs: Energy Storage Program (NJBPU, 2008)
Applicant: *Jersey Central Power & Light Company*
Summary: JCP&L seeks Commission approval to obtain 3 MW of demand response through an electricity storage program consisting of the deployment of three large battery systems at substations as well as customer-located electricity storage systems.
Case Status: Withdrawn

References for the above cases can be found in the references section.

3.1.2 Synopsis of Hearing Record Discussion Regarding the Definition of Energy Storage

For investment recovery cases to be properly analyzed, the operational definition and goals for energy storage technologies must be defined. While the technical definition was stated earlier in this report, an operational definition (identifying what specific applications or functional uses it will serve) is lacking. Furthermore, goals for energy storage must be articulated and have not been.

In the *AB2514 Rulemaking* hearing, the need to define energy storage and state its goals (or purpose on the grid) has been identified as a means to expedite future analysis of storage projects. The question is asked, ―What the goals are for energy storage in the current grid, in the future, and is there a priority for energy storage towards a specific goal?" (CAPUC, 2010c Doc. 129824). In many of the rate cases studies, questions about the operational definition and goals for energy storage were a recurring theme.

For example, in the Texas PUC case for the Presidio NaS battery, this issue was of significance. Interveners, specifically the TIEC (Texas Industrial Energy Consumers) and PUC staff, highlighted the lack of an operational definition of energy storage, with differing operational classifications for the resource based on their differing perspectives. Arguments were made by the TIEC that energy storage acts as generation because it delivers electricity to the grid. Thus, it would not be eligible for recovery under the utility's TCOS (transmission cost of service) tariff. The PUC staff made the argument that the battery would act partially as transmission (when providing reactive power) and partially as distribution, and thus partial recovery was warranted. Lastly, the applicant distribution utility, Electric Transmission Texas (ETT), made the argument that the battery would act as transmission only and thus deserved cost recovery (ETT, 2008).

This case raised the issue of asset categorization. The argument is that to classify a device as a particular type of asset (generation, transmission, or distribution), its operational definition must be defined. In this case, the Texas PUC had not determined the operational definition and goals for energy storage in the Texas electric grid. This issue arose as a major discussion point in the case and may reflect the fact that energy storage, outside of pumped hydro, is a relatively new concept and there was a lack of an operational definition or clear goals. Note that the Texas electricity system is operated differently from the rest of the United States, as most of the state is not under FERC jurisdiction. Transmission is operated by ERCOT (Electric Reliability Council of Texas) and the rates for transmission and wholesale power are under the jurisdiction of the PUC.[14]

Due to a lack of determination about the use of energy storage systems going forward, the Texas PUC made a decision based on the specific intended application of the battery system, and was careful to state that the decision would not set a precedent for future cases. Since ETT proposed to use the system as transmission, for transmission deferral (and improvement), and provided evidence for its use , ―The Commission [found] that ETT's proposed use of the NaS battery [was] appropriate for a transmission utility because the battery system provides benefits associated with transmission service operations, including voltage control, reactive power, and enhanced reliability" (ETT, 2008 Item #114).

The counterargument made by the TIEC revolved around their assertion that the device was not moving energy from point A to point B, was instead generating energy at a singular point, thus not eligible for transmission recovery, and instead generation. This argument, however, was rejected by the PUC because the device did ―provide benefits associated with transmission service operations" as mentioned in the previous paragraph (ETT, 2008 Item #114).

3.1.2.1 Discussion on the Definitions of Energy Storage

The question about operational definition can potentially be divisive with differing opinions as to whether storage is a novel concept that provides an entirely new service and should be classified as such, or if it is just another technology, providing the same services as others. Regulators are likely to face this issue, especially when storage systems are considered for applications by transmission and distribution utilities.

The Texas case paraphrased above provides an opportunity to delve into the asset categorization issue associated with energy storage systems. Services provided by energy storage systems have been described in a variety of ways by those who enumerate the specific services and arrive at individual services or benefits numbering in the high twenties (Eyer & Corey, 2010) as compared to those who articulate a simpler view.

At a fundamental level, energy storage systems provide one or both of two services—capacity and energy—as do all other active systems on an electric grid. In this sense, what makes EES systems unique is their ability to absorb and store energy up to the limit of their storage capacity. These systems may have advantages of scale due to modularity, be pollution free in their operation (except indirectly from the electricity used in their charge mode), and be more accurate and responsive to the need for their service as opposed to alternatives. These variables, together with their relative cost can help potential users of the technology make a choice between these and other alternatives available to solve grid issues and problems.

A takeaway from these hearings is that regulators may wish to decide how storage proposals will be evaluated. Regulators may decide on an operational definition for energy storage technologies and on the goals for these technologies within the electricity systems in their jurisdictions. Considering that storage systems can provide service across asset classifications, this issue may need to be resolved lest it

[14] Apart from a few small interconnections that connect to generators across state lines, most of the Texas grid is not connected to the rest of the United States and is thus an intrastate network. ERCOT operates as an independent grid and thus its transmission service and wholesale power rates are free from FERC regulation and instead under PUC regulation.

For more information see: J. Totten, "Development of Competition in Electricity in Texas," Environmental & Energy Law & Policy, vol. 1, p. 10, 2006.

unnecessarily restricts the value of energy storage technologies and makes it more difficult for PUCs to evaluate their proposed use.

The problem with using specific classifications is that not all alternatives may be considered. Storage should be chosen as the appropriate technology if, after review, it is found to be the optimum economic and technical choice among alternatives.

To ensure cost-effectiveness and efficiency, energy storage technology proposals should be evaluated against all other assets that can provide comparable services. These observations about energy storage should clear the way for more straightforward evaluation of the efficacy of energy storage systems vis-à-vis other technologies that can provide these same services. This is reinforced by a basic principle of benefit-cost analysis that when benefits of different options are identical, as they would be in this case, alternatives can be evaluated based on their comparative cost.[15]

3.1.3 Synopsis of Hearing Record Discussion Regarding Why Energy Storage is Necessary

The necessity for a storage system is yet another issue raised in many of the rate and approval cases and is a challenge for energy storage system deployment. Not only is it a question of the necessity of the services that a storage system provides, but also of the necessity of energy storage relative to an alternative, including —no action.” The necessity of deploying an EES can be more easily addressed if the definition and goals for energy storage are well defined by regulators.

In the Texas Presidio NaS battery case, the state's PUC staff raised the question about the necessity for a storage system and asked Electricity Transmission Texas (ETT) to prove this need quantitatively by supplying the documentation, data, and calculations used (ETT, 2008 Item 25). There was a similar situation for Pacific Gas & Electric in its Pumped Storage filing where it was asked about specific metrics used to prove the necessity for the proposed storage system. These metrics included whether integration studies were conducted, and how load and capacity calculations for demand and supply were determined (CAPUC, 2010a Doc. 124414) .

The determination of necessity can be a challenge in the approvals process for such cases. ETT proved necessity through reliability data of the targeted application and viability through historical data for similar storage system operation (ETT, 2008). PG&E attempted to prove necessity through the need to address renewables integration issues.

3.1.3.1 Discussion on the Necessity for Energy Storage

For regulators ensuring that the question of necessity is appropriately answered before approving recovery cases that may burden ratepayers is a critical issue. In the case of the PG&E project, necessity for the service provided by the storage system was not proven in the opinion of the Commission, and thus ratepayers were saved a significant rate burden.

Part of the issue is that the need is for grid services to maintain reliability or other quantity and quality of service criteria in the face of emerging electricity grid trends, not for energy storage *per se*. Again, alternatives to EES must be evaluated. If the analysis is framed in terms of these requirements, requestors will likely have a stronger case for a solution in the form of more energy or capacity, or both. Then the

[15] The likelihood that benefits will be the same is open to discussion. It may be an infrequent occurrence. Nonetheless, in the situation that the benefits are different, it should be a relatively straightforward process to account for the difference.

discussion can proceed to which of a variety of alternatives, including possibly an energy storage system, is the best solution under the circumstances.

3.1.4 Synopsis of Hearing Record Discussion of the Cost-Effectiveness of Energy Storage

As can be expected, in every case reviewed, regulators and interveners have asked the applicant for an analysis of the proposed system's cost effectiveness and how the system compares to alternatives. The major challenge is proving that the proposed energy storage system is cost-effective when compared to alternatives, and is thus the best alternative for the intended situation.

The determination of cost-effectiveness requires a benefit-cost analysis. Energy storage technologies have a large number of potential benefits that may apply in different situations as frequently discussed in the literature. Depending on the situation, one or more of these benefits may apply. That determination is made by the situation in which the system will be installed, the technology being used, and the potential for obtaining a value stream by supplying the benefit. This complexity is where the real issue lies and can create challenges for regulators attempting to analyze specific proposals.

In order to prove cost-effectiveness, these benefits must be quantified. Markets are not present for most benefits and even in the states where the markets exist, it can be difficult to obtain a proper valuation of benefits because markets have been developed to accommodate conventional generation resources. Accordingly, markets are unable to take into account the potential of increased quality of service that energy storage systems can provide, thereby devaluing EES. A challenge for regulators is the development or adaptation of markets in deregulated states and proper analysis techniques in regulated states, to allow energy storage technologies to have economic value for the quality of benefits that they can provide. This issue has been raised in a number of comments in the California *AB2514 Rulemaking* (CAPUC, 2010c Doc. 129824, 129843, 129820).

The Jersey Central Power and Light Company (JCP&L) demand response filing with the New Jersey Board of Public Utilities (BPU) highlights some of the benefit determination issues that are representative of the problems in determining cost-effectiveness (NJBPU, 2008). While it is important to remember that this is a pilot project, and certainly, JCP&L is using that to counter arguments that its proposal is not cost-effective, the issues raised would be pertinent to a full-scale installation. Furthermore, considering the broader perspective that a pilot project provides an additional economic benefit, it could be argued that the JCP&L demand response filing is a cost-effective undertaking.

In its filing, JCP&L presents benefit quantifications for those value streams that it believes it can quantify, specifically, demand reduction compensation from PJM by registration in its Economic Load Response program and ILR (interruptible load for reliability) capacity credits. However, these value streams are not enough to repay capital and operational costs for the system. The utility also presents other value streams that it believes would increase the cost-effectiveness of the proposal, however, states that it is unable to quantify them. These include system reliability improvements, peak load reduction and thus lower market pricing, transmission and distribution deferral, a reduction in the operation of less efficient generation units, a reduction in the necessity for new generation, and environmental benefits.

The argument made by JCP&L is that the pilot project would help in determining the value of these benefits. However, despite this argument, a consultant of the BPU's ratepayer advocate board testified that the value could be quantified and cited examples of value quantifications as conducted by other utilities. Thus, the consultant suggested that a pilot project would not be justified since the technology is proven and the benefits could be determined (NJBPU, 2008 Hornsby Testimony 7/23/2009).

Since the JCP&L case was a pilot project, alternatives were not considered, but the question was posed. In the case of the Presidio installation, the question of alternative technologies was much more important. Regulators had to consider whether the applicant fully analyzed the alternatives to the energy storage system and conducted a benefit-cost analysis to determine the most cost-effective option. In this case, the Texas PUC decided that the utility had provided an adequate argument for cost-effectiveness of the storage system (ETT, 2008 Item 114).

3.1.4.1 Discussion of Cost Effectiveness

The JCP&L case highlights the difficulty in quantifying the value streams that storage systems can provide. The benefits considered in this docket were system reliability improvements, peak load reduction and thus lower market pricing, transmission and distribution deferral, a reduction in the operation of less efficient generation units, a reduction in the necessity for new generation, and environmental benefits. While it may be difficult to quantify some of these benefits, it is not impossible to produce an estimate, as indeed has been done so for a number of demand response programs around the country. Importantly, a reasonable estimate can help to substantiate the business case for storage systems. Improved estimates can always be provided later when more information and data may become available.

Some system reliability services may be quantified through avoided ancillary service costs. Utilities should know what their costs are in delivering ancillary services and thus reliability from a storage system could be represented by this metric. The benefit of peak load reduction and lower market pricing could be quantified through production cost simulation with and without the storage resources in place, with the difference in production cost signifying the benefit.[16] Transmission and distribution (T&D) deferral benefits could be quantified by an analysis of the T&D system to determine where deficiencies lie with the costs required to address these deficiencies identified as the benefits.

The benefit of the reduction in the operation of less efficient generation could be quantified by an evaluation of historical data reflecting the operation of such units and how an energy storage system would affect their operation. This could also be accomplished through production cost modeling. The benefit of avoided cost from investment in new generation units could also be quantified with production-cost modeling, or even a more simple analysis of expected load and generation capabilities.

Finally, environmental benefits could be quantified through a projection of avoided carbon dioxide, nitrogen oxide, and sulfur dioxide emissions using estimated CO_2 and NO_x prices, and the market price for sulfur dioxide credits.

To assist regulators in streamlining the approval process and answering the question of cost-effectiveness, regulators must insist on and support a full benefit-cost study, though sometimes difficult in deregulated utilities, that includes all of the issues and compares all possible alternatives on an equal footing. An important strategy for a utility is to use a proper accounting process and a thorough explanation of how the analyses were conducted.

The evaluation of the cost effectiveness of energy storage systems should be no more difficult than the evaluation of other assets that contribute to the delivery of electrical energy. Many writers and commentators have written extensively on the many benefits and unique features of energy storage systems. The benefits discussed in this paper and the longer lists of benefits that appear in the energy storage literature could, with but one exception, be applied to any technology presently on the grid or technologies to be added in the future. The exceptions are the unique ability of energy storage systems to

[16] The benefits and limitations of production cost modeling are discussed in the evaluation approach section.

absorb and store energy and hold it for a time into the future, and the ability to adjust their output level significantly in microseconds. However, some of the benefits may result in double counting if applied to an actual analysis. For example, time shifting of energy is equivalent to peak shaving; intermittency and sustaining increased renewables generation are equivalent. Care must be taken to avoid double counting in an analysis.

These comments go to making the evaluation of energy storage systems more tractable. Indeed because there are usually alternatives for most or all of the benefits of a grid investment in storage, the benefits of the available alternatives may be equivalent meaning that the alternatives can be evaluated based on their cost to deliver the benefits. The possibility exists that doing nothing would be more cost effective and thus should be evaluated as an alternative as well.

If the intended functional use calls for energy time-shift or, as it is sometimes referred to, energy arbitrage, evaluation of these benefits simply amounts to a demonstration that the cost of charging the storage device is sufficiently less than the value it attributes to energy at the peak demand so that payback of the investment, coverage for operations and maintenance costs, and return on investment justify the expenditure. The value of an MWh of energy at peak, at a minimum, would be the reduction in operating cost of the marginal resource at the peak hour. In a market environment, the value of energy could be higher than this minimum.

It is claimed that service stacking (accumulation of multiple revenue streams from providing multiple grid services) can be a potential advantage of energy storage technologies over other alternatives and should be considered by regulators when evaluating proposals. As mentioned above, often it may be difficult to quantify singular benefits, and the possibility of stacked benefits makes this issue more difficult. The stacking of benefits leads to the possibility that the full value of each benefit cannot be served by the device due to technical limitations. It is difficult to quantify the value proposition when considering stacking. It is important to take care not to double count benefits and ensure that the device can actually deliver the multiple benefits under customary operating conditions. For example, an energy storage device that needs to be at a minimum state of charge for a potential reliability service may not be available to provide its full value to frequency regulation service. Additionally, benefit stacking can place other limitations on the storage system, for example, reduced discharge time, increased wear, reduced useful life, and the potential for premature failures. Research is ongoing to determine whether there is a negative effect on EES technologies, but it does become an important issue to consider when evaluating the stacking of benefits.[17]

The capability of stacking benefits is not unique to energy storage systems. Most assets on the grid supply multiple benefits. For example, a natural gas plant can supply both energy and voltage regulation services and there is an inherent tradeoff between providing the two services.

3.1.5 Synopsis of Hearing Record Discussion of the Utilization & Operation of Storage

Other issues that have arisen during rate case proceedings concern EES device utilization and operations. From an operations perspective, it is important that regulators have adequate understanding of how a particular storage system will be used. As a result, in order to make the strongest case possible, any proposal filed by a storage system owner should include the following items: *(These items have been aggregated from questions posed in the rate cases reviewed as referenced)*

[17] A number of tools are available from research organizations and private consultants that attempt to value service stacking for different grid uses.

- A description of the storage charging and dispatching algorithms (are the added levels of complexity manageable?)
- The scale of deployment of the system
- The strategy of deployment
    - The capability of the system to provide stacked benefits
- The maintenance that will be required and its costs
    - Whether the workforce is present to maintain the system
- How the storage system will fit in to the system overall
- How the storage system will fit into the future electric system

In the rate cases reviewed, there was not significant discussion on these questions, but they were asked in most instances. As a result, determining the answers to these questions can help to conduct an expedited analysis of a proposed system. Though these questions may expedite system processes, it is important to note that continued product development may be required to provide a comprehensive response to these inquiries.

3.1.5.1 Discussion of Storage Utilization and Operation

The charging and dispatching algorithm issue is a pertinent one for storage, though this issue may be more of a problem for regulated utilities proposing energy storage systems in market areas. In the case of a regulated vertically integrated utility, however, this should not be a problem because the utility would presumably know the values and costs of charging and discharging as these are internalized within the entity, signaling one reason to believe that EES systems might be successful in regulated, non-market areas.[18] The utility would meter its purchases of energy for charging in order to build a cost and performance record for the asset and would clearly meter energy the device releases for resale. In market areas, both charging and discharging would be compensated at market clearing prices.

3.1.6 Synopsis of Hearing Record Discussion of Funding Issues

Funding issues are obviously of key importance when regulators consider approving storage technologies for rate recovery.

Once a storage system has been deemed the appropriate technology for a particular application, the next question to answer is how to determine the amount of rate recovery to be approved (and requested from the utility standpoint). Questions of whether outside funding (from states, federal entities, shareholders or other entities) was obtained for projects have been prevalent in these cases, especially since many consist of demonstrations.

Another question of importance for a state regulator is that of cost control. Proposals should include cost containment methods that prevent costs unnecessarily rising in the future from the installation of storage projects. PUC staff and other interveners have insisted that there should not be instances in which a utility requests additional cost recovery for a storage system that was approved for a specific amount in the past. Any potential for this to happen should be addressed within the initial proposal (CAPUC, 2010a Doc. 124414).

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[18] It is important to note that while vertically integrated utilities (including generation) should be able to account for all costs within their systems, in practice, this may be difficult.

3.1.6.1 Discussion of Funding and Financing Issues

Funding and financing issues across the different organizational structures evident in the current state of the electric industry are not directly comparable and thus a broad statement cannot be made on an approach. The approval of financing and the appropriate recovery amount for an EES project will depend on the standard financing process of each PUC. The fact that EES systems are a different technology should not complicate their funding. As for the issue of cost control, it will be up to a LSE and the PUC to ensure that appropriate cost control procedures are in place to prevent the need for a secondary rate recovery request.

The modular design of many energy storage technologies presents a potential funding and financial benefit: utilities can build projects to immediate requirements and expand them as appropriate if demand arises. This allows deferral of capital funding until needed, potentially addressing issues of uncertainty associated with an otherwise larger capital investment.

Regulated utilities may also be able to obtain rate base relief for asset investments that have an experimental, demonstration, or pilot project aspects to them. The PG&E response is on target as a response to this issue. Experimentation and demonstration benefits all parties to the effort including those ―inside” the project as well as those ―outside” the effort. This positive externality cannot be reduced to revenue streams. Indeed, California, Colorado, New York, and New Jersey, amongst a number of other states, have provided cost recovery for EES systems for pilot purposes. Other states may also benefit from such an approach.

3.1.7 Synopsis of Hearing Record Discussion of Markets

Market challenges can also play a significant role in affecting energy storage deployment, specifically in regions of partial deregulation, such as California. A key question raised in the rate case hearings for the *AB2514* process was whether rate recovery for a storage system asset would prevent the establishment of competitive markets. Specifically, the issue that arose in the discussion was whether energy discharge from the installed storage technology would have an effect on wholesale pricing. If this were to be the case, it would be an unfair bias towards regulated utilities that could reduce the potential for revenue for IPPs attempting to compete in the wholesale market (CAPUC, 2010c Doc. 129819).

Along these lines, the issue of mixing retail and wholesale rates was also raised, again with the argument that the possibility for the mixing of rates (by a singular storage system purchasing at wholesale and selling at retail) should be closely monitored to prevent the potential for market distortion (CAPUC, 2010c Doc. 129882).

The point of both issues is to highlight the concern among stakeholders that without proper oversight there may be instances of market distortion that allow entities to obtain rate recovery while participating in wholesale markets.

3.1.7.1 Discussion of Markets

States that instituted unbundling and functional separation may still be subject to ―seams” issues between areas subject to market allocation of wholesale resources and integrated utilities. California is a good example. While all of the IOUs in the state divested generation assets in one way or another and have their transmission networks operated by the ISOs, there remain two important municipal utilities in the state that remain functionally bundled. The functionally unbundled former IOUs are now load serving entities who own and operate the distribution network and retain the retail end of the business. Such entities might wish to install energy storage systems in the distribution network on either side of the customer's meter. To obtain rate base approval for such an investment would require the entity to make its case before the state's public utility commission in order to obtain approval. The commission is responsible for ensuring that the project benefits the customers it represents.

Correspondingly, an IPP or merchant plant could install an energy storage device at or in conjunction with a generation asset it owns, with a view to bidding the assets' services into the relevant market. In this case, the technical characteristics of the asset would be tested by the system operator who would designate the asset as approved and would allow the services of the asset to be bid into the market. The system has checks and balances to prevent regulated utilities to obtain rate base approval for an asset and simultaneously to bid that asset into a market.

3.1.8 Synopsis of Hearing Record Discussion of Mandates and Incentives

Another issue that arises when considering energy storage systems is that of mandates and incentives. At present, no such mechanisms exist that require the deployment of energy storage resources. In the case that a regulator determines that such mechanisms are necessary, they can be implemented, increasing the amount of rate case approvals for storage systems.

Recently, the ruling issued in California, *AB2514*, granted the California Public Utility Commission the discretion to implement procurement mandates as it determines appropriate to ―procure viable and cost-effective energy storage systems" (CAPUC, 2010c). The question that the California PUC must address is whether such mandates would be appropriate and whether they are even necessary: is the increased value in deployment and cost reduction worth the initial cost of the mandates to ratepayers? There are a number of potential mandates that could be implemented, ranging from defined minimum standards, to increased utility rates of return for energy storage investment, to feed-in tariffs.

3.1.8.1 Discussion of Mandates and Incentives

Regulatory commissions do not typically have the authority to establish mandates. State legislatures must either establish mandates directly through legislation or, again through legislation, extend the authority to the state utility regulators to establish mandates, as has been the case in California. Mandates and incentives can increase the deployment of new technologies. This has been amply demonstrated by the renewable portfolio standards that many states have for wind, solar, and other alternative energy technologies, and can be applied for energy storage technologies as well. It can be argued that energy storage should also receive *favored* status as has been done with renewables.

However, mandates can also have unexpected or unintended consequences that can create problems and issues. Renewable technology integration is just such a situation, where technologies that were not necessarily cost-effective were implemented. In general, it may be better for government to provide technology development support and let locally knowledgeable people, either private investors or utility personnel, who are closer to the issue, make decisions about when and where to deploy new technology, basing their decisions on economics and other local issues.

The issue of mandates and incentives, and how they can apply to energy storage, is discussed further in section *3.2.4 The Challenge of Mandates and Incentives*.

3.1.9 Synopsis of Hearing Record Discussion on Evaluation Metrics

The *AB2514* rulemaking required that regulators establish a defined set of metrics to help in the evaluation of energy storage rate cases.

A list of different evaluation metrics that were proposed by the California Energy Storage Alliance (CESA) for the proper evaluation of storage technologies can be found following the reference ―Smart Grid Rulemaking" to Doc. 114772 (CAPUC, 2008 Doc. 114772).

3.1.9.1 Discussion of Evaluation Metrics

An analysis of the other rate cases indicates that there may have been a benefit from such metrics in the evaluation process. The lack of metrics presents a potentially significant challenge to increased energy storage development. Performance and economic metrics can help to define the appropriate value for each technology in order to compare energy storage to other alternatives on a cost-effectiveness basis. Indeed, manufacturers cite a lack of defined metrics and standards as a deterrent in properly evaluating energy storage technologies, not only against alternatives, but also amongst each other. Metrics can also help to determine the appropriate rate recovery amount.

While a few of these metrics would be specific for storage technologies, it would be valuable if the metrics used to evaluate services to the grid would be applicable to multiple grid assets (technologies), or in other words, be technology independent. This would simplify the process of directly comparing different alternatives to determine the most cost-effective technology to serve a desired application.

Thus, this discussion relates back to the earlier discussion of cost effectiveness and benefit-cost analysis. Metrics for the evaluation of assets in the grid do exist and have regularly been used to evaluate other investments. Many of these metrics could be applied to energy storage systems. Utilities proposing such additions to the rate base are experienced in conducting evaluations and can be relied on to perform the analysis.

3.2 Summary of Challenges and Regulatory Responses

Energy storage systems may become important elements of the electricity grid and marketplace of the future. Emerging and advanced storage technologies and systems may become more flexible, more efficient, and have lower costs, making storage a viable alternative to other grid solutions.

However, energy storage systems currently present higher costs than alternative technologies in many of the same applications and therefore have difficulty bringing incremental value to the grid. Some of the factors resulting in higher costs include important institutional challenges facing prospective users of energy storage systems. In order for EES to bring incremental value to the grid, there should be a shift in focus from technology cost to technology value.

Challenges and possible responses presented in this section are based primarily on input from several knowledgeable stakeholders. In some cases, stakeholders provided written comments. In other cases, stakeholder perspectives were elicited during interviews.

3.2.1 Storage-Specific Challenges and Responses

3.2.1.1 EES Benefits Have Not Been Demonstrated and Verified

While EES systems can be solutions to many electric grid problems, particularly the emerging issue of reserve adequacy (RA) in the face of expansion of renewable energy, there has been very few “real” deployments of energy storage systems under conditions other than as pilot and/or demonstration projects. Many installations of deployed energy storage systems resulted either through the lowering of approval standards for various reasons, or financing assistance from public entities, or both, and accordingly do not represent realistic deployment conditions. For example, ARRA projects were partially publicly financed and did not pass through the normal regulatory process. Demonstrations are valuable for validating technology performance characteristics and interaction with the grid. However, their value in verifying the economics and longevity of the storage systems are limited and as a result do not entirely eliminate risk.

The lack of actual experience with EES increases the riskiness of investment not only for the utility that needs to recover its investment but also for utility commissions that need to ensure that they serve electricity consumers’ interests mainly through maintaining low electricity rates. This is a typical problem for breakthrough technologies and was the problem for renewable energy systems for a long time. Renewable Portfolio Standards (RPS), a state regulation that requires the increased production (usually based either on capacity or sales) of energy from a specified renewable energy resource, and other policy initiatives helped these systems to establish a broader market presence and as a result, lower costs. While this solution is not endorsed by this report, it is a policy under consideration in some states and could play a role to address some of these concerns. This issue is discussed further in section *3.2.4 The Challenges of Mandates and Incentives*.

3.2.1.2 Institutional Inertia

Related to the issue of the lack of “real” successful *(i.e., profitable)* implementations of EES is the observation that the electric utility industry has become a very risk averse industry, and to a large degree has lost the initiative for adopting emerging technologies to the private sector (Hirsh, 2003).[19] To a considerable extent, this evolution is due to the policy initiatives evident in the Public Utility Regulatory Policy Act of 1978 and to subsequent initiatives by FERC leading to the unbundling of utilities. The expansion of renewable energy technologies has largely been developed outside the regulated utility industry, even though electric utilities have assumed some of the market risk by signing power purchase agreements with private developers. The latter have assumed most of the technology risk.

It seems worth remembering that the two great technological revolutions that took place in the electric utility industry since the middle of the 20th Century—the deployment of nuclear power in the 50s through 70s and the currently evolving deployment of wind and solar power—were and are the focus of substantial public policy initiatives. Indeed, the federal government is currently heavily involved in the effort to restart the construction of nuclear power plants. There is history of substantial subsidization of our energy industries.

[19] Hirsch delves into considerable analysis of this issue in his book: he documents the transformation of the utility industry very thoroughly (Hirsh, 2003).

3.2.2 Uncertainty Regarding Jurisdiction of FERC and State PUCs over Storage

One important challenge raised in the docket discussion is the uncertainty surrounding jurisdictional authority between FERC and State PUCs. In a fully regulated, fully bundled service territory, clear lines of jurisdiction exist for energy storage as for all other grid assets. State Public Utility Commissions have regulatory authority over generation, transmission, and distribution provided by the utilities they regulate with the exception of transmission that enters interstate commerce. Regulatory forbearance permits FERC to take jurisdiction over bundled wholesale transmission services entering interstate commerce. Examples describing activities or actions by FERC, an RTO, and a state PUC legislation, including positions taken from FERC dockets, describe ways that the use of energy storage resources can create jurisdictional uncertainty between state and federal regulators.

3.2.2.1 FERC

The Federal Energy Regulatory Commission (FERC) is at the heart of the discussion of electric energy storage jurisdictional uncertainty. The issues and concerns brought before the Commission involve business and jurisdictional issues including reliability coordination of variable renewable energy sources, regional protection of indigenous power sources, disagreements over cost structure and allocations, resource planning responsibilities and incumbent transmission ownership in opposition to merchant transmission privileges. The legal basis of FERC jurisdiction over EES was established in a court of law and expressed as jurisdiction involving two aspects related to electric energy business:

- Transmission of electricity across state borders (interstate commerce); and
- Sale of electricity at wholesale.[20]

Pomper (2011) indicates that the initial case identifying where FERC's ruling led to uncertainty in its jurisdiction over EES is *Norton Energy Storage L.L.C.*[21] *Pomper* holds that FERC declared its jurisdiction over energy storage by classifying the charging and discharging process as wholesale transactions and under its exclusive authority under the Federal Power Act rather than state-jurisdictional retail transactions (Pomper, 2011, pp. 2-3). The Commission used the filing to speak to the process of converting electricity to another form of energy (water as this was a pumped storage proposal) in the charging mode then converting it back to electricity through discharge constituted a wholesale transaction and therefore under its jurisdiction over wholesale energy sales. This decision led to further uncertainty when FERC ruled on two other cases involving a pumped storage project in Nevada called The Lake Elsinore Advanced Pumped Storage (LEAPS).

The LEAPS project is an example where energy storage applications could be subject to state (or regional) and federal regulatory authorities. The developer intended to use the facility for transmission services and sought cost recovery through the California ISO (CAISO) transmission recovery charge (TAC) as well as an increased rate of return grant from FERC. The Commission rejected the transmission tariff request indicating that it would not be appropriate for the system to be under exclusive control of CAISO as would be required under the TAC.[22] Under the proposer's operational profiles, the system would have the potential for the ISO to obtain profit from the time sensitive pricing. The Commission

[20] *NY v FERC, 535 U.S. 1, 20 (2002) and 16 U.S.C., Section 824 (b)*

[21] *Norton [95 FERC; 61,476 (2001)]*

[22] *Nev. Hydro Co. 122 FERC ¶ 61,272, at 82-83 (2006)*

made the point that other pumped hydro systems collect revenue through participation in wholesale power markets and allowing rate recovery would provide an unfair advantage.[23]

The Commission made a different determination in its hearing on *Western Grid Development, LLC*. In this case, the *Western Grid* requested transmission rate recovery with increased rate of return for a number of Sodium Sulfur (NaS) batteries installed at selected areas in CAISO territory intended for transmission relief.[24] The Commission found that since the proposal called for CAISO to maintain full control over discharge, that no power would be bid into energy or ancillary service markets, and that any additional revenue from price differentials in charge and discharge would be credited to ratepayers, the systems could be classified as transmission facilities. The proposal was approved for transmission rate recovery and increased rate of return under FPA section 219 and FERC Order 679 for transmission investment promotion.[25] FERC explicitly mentioned that the *Nevada Hydro Co.* case was a different situation.[26]

These three cases highlight that uncertainty arises with the use of energy storage systems. The *Norton* case highlights jurisdictional overlap issues between state PUCs and FERC. The other two cases highlight FERC's views on energy storage technologies. Considering that they are so varied in performance characteristics and can serve a number of functions across the traditional asset classification regime, there is difficulty and uncertainty in rate recovery characterization.

FERC explicitly states that energy storage systems —do not readily fit into only one of the traditional asset functions of generation, transmission or distribution. Under certain circumstances, storage devices can resemble any of these functions or even load. For this reason, the Commission has addressed the classification of energy storage devices on a case-by-case basis."[27]

This uncertainty about classification and jurisdiction potentially creates issues for utilities and developers proposing energy storage systems, and state regulators evaluating their use. An overall policy is not in place that allows potential storage system users a clear path towards deployment.

3.2.2.2 PJM

PJM is currently the world's largest competitive wholesale electricity market serving as a regional transmission organization (RTO) for large portions of the Eastern Interconnection grid. It has engaged FERC on the question of electric energy storage. PJM defines an —Energy Storage Resource" in a limited fashion as only two technologies – flywheels and batteries in order to use these as generation support.[28]

> *"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short-term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.*

[23] *Nev. Hydro Co. 117 FERC ¶ 61,204, at 29 (2006)*

[24] *Western Grid Development 130 FERC ¶ 61,209, at 1-5 (2010)*

[25] *Western Grid Development 130 FERC ¶ 61,209, at 43-52 (2010)*

[26] *Western Grid Development 130 FERC ¶ 61,209, at 17 (2010)*

[27] *Western Grid Development 130 FERC ¶ 61,209, at 44 (2010)*

[28] *PJM Interconnection, L.L.C.,*132 F.E.R.C. ¶ 61,203 (2010)

The Commission accepted PJM's filings and its request to have energy storage resources excluded from ―station power."

> *"Station power shall mean energy used for operating electric equipment on the site of a generation facility located in the PJM region."*

3.2.2.3 ERCOT/PUCT

Much of the state of Texas is self-contained in ERCOT, its own RTO. It has a PUC (PUCT) that regulates the state's electric utilities and ERCOT itself. The ERCOT and PUCT substantive rules that govern electric utilities define only two types of resources – either generation or load. On June 5, 2011, Governor Rick Perry signed into law Senate Bill 943 that permits energy storage projects the right to participate in the competitive wholesale electricity market by providing generation services. This bill is presently being formulated into a protocol through ERCOT's stakeholder working groups.

The definition of electric energy storage equipment or facilities is in the definition of a ―Power Generation Company." A power generation company (PGC):[29]

(a) Generates electricity that is intended to be sold at wholesale;
(b) Does not own a transmission or distribution facility in the state; and
(c) Does not have a certified service area.

The PUCT allows the PGC owner or operator of such storage equipment or facilities to interconnect, obtain transmission service, and use the equipment or facilities to sell electricity services at wholesale.

Not all questions have been resolved about the services that qualify as storage participation (non-spinning reserves, regulation up, responsive reserve, etc.). Additionally, limited energy storage resources (LESR) have not been explicitly addressed in this determination. The PUCT and ERCOT are continuing work on evaluating whether further rule changes may be needed to address LESRs. There is also a pilot project on evaluating fast responding resources (a benefit of EES relative to other technologies) for use to provide ancillary services and modified payment mechanisms for this faster response.[30]

As discussed previously, any storage asset intended for transmission and distribution use would need to be approved for rate base by the PUCT. In approving the NaS Presidio system, the PUCT made clear than any such evaluations will be on a case-by-case basis. As is the case in jurisdiction regions under FERC, a T&D asset cannot provide generation services and a generation asset cannot provide T&D services. Any change to this would require a change in state law, and would likely be a contentious process.

3.2.2.4 Utah Public Service Commission

Utah does not have a mandated RPS. In states that have an RPS, fines can be imposed if utilities fail to meet production and timeframe goals.

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[29] *Project 39657, section 14.002 (Vernon 2007 and Supp. 2010) PURPA Chapter 35 modified S.B. 943*

[30] See ―Fast Responding Regulation Service" http://www.ercot.com/mktrules/pilots/ & Texas Energy Storage Alliance http://texasenergystorage.com/

The Utah Public Service Commission has jurisdiction over the state's investor owned and cooperative owned public utilities according to Utah Code 54 Section 2. The Division of Public Utilities can make recommendations that involve ratemaking, applications, and quality of service to the UPSC. Utah Docket No. 09-2035-01 (June 18, 2009) includes strong comments by the Western Resource Advocates that were critical of the Integrated Resource Planning (IRP) submitted to the UPSC by PacifiCorp.[31] The WRA anticipated climate change regulation, which would result in a carbon tax to Utah electricity consumers. To that end, WRA pushed strongly for use of wind and other renewable resources. There were two energy storage paths in this scheme of preventing damage to the end user. The first involved Compressed Air Energy Storage (CAES), which was to serve as a generation asset within the Western Electricity Coordinating Council (WECC).[32] The other course of action included the UPSC pursuing solar photovoltaic (PV) that, when coupled with energy storage, would serve as transmission deferral.[33] The asset would follow FERC jurisdiction and operating guidelines.[34]

In each of these cases, the ―intended use" of the equipment or facility can be applied to help establish if the energy storage should be considered a generation, transmission, or distribution asset.

3.2.2.5 "Avista Restriction" Relation to EES

The so-called ―Avista Restriction" (AR) arose out of a FERC ruling in 1999 prohibiting ―third-party market-based sales of ancillary services to transmission providers seeking to meet their ancillary service obligations under the Open Access Transmission Tariff (OATT), absent a market study showing lack of market power."[35] While this restriction pertained more generally to the provision of ancillary services (a phrase appropriate only as applied to wholesale market areas), many within the ―storage community" interpreted this to mean that the EES issue was taken up by FERC in this case. This belief is bolstered by the fact that the Avista Energy facility involved was a storage technology (pumped hydro) which applied to have its capital investment compensated as a transmission asset.[36] FERC's initial ruling in the case defined storage technologies as transmission assets and therefore subject to FERC jurisdiction.

In the more recent NOI (notice of inquiry), regarding third party ancillary service provision and EES accounting requirements, FERC sought to clarify its position in the original Avista ruling.[37] It requested input on the issue of ―(1) whether revising or replacing the restriction set forth in *Avista Corp.* (referred to as the *Avista* restriction) which prohibits third-party market-based sales of ancillary services to transmission providers seeking to meet their ancillary services obligations under the Open Access Transmission Tariff (OATT), absent a market study showing lack of market power, would help to

31 Utah PSC. PacifiCorp 2008 IPR

32 U*tah Legislative General Counsel, Senate Bill S.B. 104 Renewable Energy Modifications, Title 10, Chapter 19, Municipal Electric Utility Carbon Emission Reduction Act, and Title 54, Chapter 17, Energy Resource Procurement Act. This bill was sponsored by Stephen Urquhart and Don Ipson.*

33 Utah PSC Docket No 07-035-T14.

34 This example of the Utah Public Service Commission is not a conflict of jurisdiction regarding electric energy storage. It is, however, a solid description of a PUC that did not have to become involved in the potential concerns for how storage providers would fund their investments at the expense of the rate customer. Given that the UPSC was advised to pursue CAES, the discussion may eventually have to address what happens in the development of new energy storage devices, equipment and facilities and what constitutes a public utility.

35 *Avista Corp*., 87 FERC ¶ 61,223 (*Avista*), *order on reh'g.* 89 FERC ¶ 61,136 (*Avista* Rehearing Order) (1999).

36 Avista made this case in order to have access to the (presumably higher) transmission tariff, which the FERC ruling permitted.

37 135 FERC ¶ 61,240 18 CFR Chapter I [Docket Nos. RM11-24-000 and AD10-13-000] Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies (June 16, 2011)

facilitate the provision of ancillary services, and if so; (2) how to balance that goal with the need to ensure just and reasonable rates."[38]

Concerning energy storage, FERC is asking whether its accounting regulations are sufficient to handle energy storage facilities when they provide service that is Commission jurisdictional. The Commission would likely deem any entity providing ancillary services that are sold under an open access transmission tariff to be providing a jurisdictional service.

If this represents an accurate interpretation of the FERC position then there should be no conflict in jurisdiction between FERC and state PUCs. Vertically integrated utilities seeking rate base addition for EES are not operating in a market environment nor are they providing transmission services in interstate commerce. It is understood that the recovery of the proposed investment in EES and the return on the investment will be solely through rates charged to customers within the established service territory and from no other sources.

3.2.3 Existing Cost-Effectiveness Tests Do Not Accommodate Storage Well

This issue appears to suggest that evaluation methods should somehow be modified when applied to EES. The discussion earlier in the report regarding benefit-cost and other economic or financial evaluation criteria is pertinent here as well. Assuming the evaluation techniques are properly applied, there seems no reason that the same principles that apply to the evaluation of other technologies should not also apply without modification to EES systems.

3.2.4 The Challenge of Mandates and Incentives

The issue of mandates and incentives, as discussed above, is important, especially considering that the vertically integrated utilities in the United States have become increasingly risk-adverse. In addition, the ability to finance additional investment for many of these entities has declined over the past several decades due to a combination of financial deterioration resulting from failed diversification efforts and uncertainty surrounding industry restructuring. Getting any significant addition of a new technology to the system is unlikely to happen without a strong driving force.

In the case of renewable energy technologies, specifically wind and solar, the driving force for their increased use was mandates and incentives. The argument can be made that the only reason for their large-scale deployment are Federal and State mandates and incentives. Without incentives, in most cases, there may not be a business case, relative to alternatives, for their use. Even in the instances where there might be a business case, utilities, and even independent power producers, are generally reluctant to use these technologies.

This same issue is also relevant for energy storage systems. At present, the business case for their use in most instances relative to alternatives is not a strong one. Mandates and or incentives could provide a driving force towards increased use.

Mandates and incentives, however, may push technologies onto the electric system that lead to inefficiency. If the goal is to reduce emissions, incentives and mandates may provide a path. If the goal is to reduce system costs, it is unlikely that mandates & incentives will realize this goal, and especially not

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[38] *Ibid*., p. 2

in the short run. In either case, their use creates inefficiency. More efficient methods to reduce emissions and costs may exist.

Ideally, the internalization of the externalities associated with traditional generation would lead to the most efficient means of reducing emissions while reducing costs. By pricing carbon dioxide and other pollutants, through a carbon tax or a cap and trade system, there would be a driving force to reduce system costs, which would in turn reduce emissions of pollutants. The entities involved in providing electricity would be free to determine the most efficient means of reducing their cost, which certainly vary in different situations, whether that would be to install wind energy and use an energy storage system to manage variability, or scrub and capture pollutants from their traditional generation systems.

In the present political climate, it is unlikely that a carbon-pricing regime will be enacted. Thus to reduce emissions, mandates and incentives may be necessary for energy storage systems in order for them to penetrate the electric grid, reducing emissions by supporting renewables to displace the current technologies providing these services.

4 A Process for Evaluating Services of EES Systems

4.1 Introduction

Evaluation of the profitability of EES systems should be no different in principle from the evaluation of the profitability of other grid assets. The unique feature of EES is its ability to store energy rendering EES similar to load. In the regulated, vertically integrated, investor-owned-utility (IOU) environment, where unbundling has not taken place, the IOU has the advantage of appropriating the entire value of the service flow that an asset may provide. Thus, for example, an EES system may be deployed within the integrated utility grid to provide regulation capacity, thereby allowing a conventional generator to operate at a more efficient output level. This improves the plant heat rate, reducing fuel costs and overall emissions. This cost reduction is viewed as a benefit (reduced cost outlay) and is captured by the IOU, as are other reliability improvements in compliance with established reliability standards on the IOU's portion of the grid. The latter, while not resulting in a revenue stream, improves the IOU's portion of the grid, presenting a value stream. In a market environment, opportunities for profitable operation using EES are signaled by prices and may provide revenue streams sufficient to offset investment plus a return.

Profitability can take two forms: 1) additional revenue from the service flow received by the IOU, and 2) avoided cost outlay. Non-monetary service flow can also occur as illustrated in the above example. Examples of additional revenues from the use of EES systems include payments received for energy sales, electric supply capacity, and ancillary services. Examples of avoided cost service flows include a utility's deferred or reduced need for generation, transmission or distribution capacity additions, as well as an IOU customers' reduced cost for energy and demand charges. Examples of non-monetary service flow include excess system stability and reliability improvements beyond requirements and emissions reductions (until an emissions price is enacted).

4.2 EES Evaluation Approaches

Several alternative approaches to EES evaluation can be identified. Each approach is distinguished by the resources required to carry out the evaluation and its specificity. The evaluation approaches are not mutually exclusive and could be viewed in a continuum of increasing specificity and resource outlay.

4.2.1 Generic Studies Approach

The information and data necessary for evaluating EES technologies from a high level is already available in the literature. Details on EES applications and technology features that map to the requirements of the specified applications have been identified. This carries the analyst well into an analysis of EES as an alternative for delivering required grid services. Researchers and economists have carried these analyses even further and have attempted various evaluations that compare the costs per unit of output of specific energy storage devices to the costs of conventional alternatives for delivering the same services.[39]

However, these results, while useful, are generic, and must be for an analyst preparing work that might cover a national perspective. These general estimates cannot be used to support an actual submission by a utility for investment or rate base addition, to its regulating entity. Such a submission will require more locally specific information that is pertinent to the requesting utility's situation.

[39] See, for example, (Rastler, 2010), Executive Summary, Pages xviii-xx; (Eyer & Corey, 2010) various tables in economics sections.

4.2.2 “Down Scoping” Approach

This method amounts to a refinement of the generic approach outlined above. It uses the same methods to identify grid needs (benefits, more specifically, revenues) in specific grids and specific locations in those grids and then down selects to identify the EES technologies best suited to supply those grid needs. This selection process would precede any financial or economic evaluation as explicit recognition that site-specific conditions can greatly affect the outcome of the financial or economic evaluation of the EES technology. It reflects the difference between the questions ―Is storage economic?” and ―Is this particular storage technology an economic alternative to other alternatives at this site, in providing this service?” A further advantage of this approach is that more detailed and, presumably, accurate quotes for installed cost and operation and maintenance costs could be obtained from vendors who would supply the equipment in question. Cost uncertainty is thereby reduced. This ―down-selecting” approach is implicit in numerous studies and reports that involve the matching of EES technology characteristics with grid applications where specific grid needs can best be met (Eyer & Corey, 2010; Rastler, 2010). Southern California Edison rendered this approach into a stepwise process (Rittershausen & McDonagh, 2010).

4.2.3 Localized Economic Simulation Models Approach

A more site specific and detailed level of analysis is characterized by simulation modeling of the performance of a specific type of EES system installed into a specific location on a specific grid. Examples of such analyses are available in the literature: excellent examples are represented by Succar and Williams (2008), Hessami and Bowly (2011), Fertig and Apt (2011). These papers employ abbreviated or scaled down representations of the grid in an area immediately surrounding the intended location of an EES system. These are hypothetical but, to a degree, realistic characterizations that often include a single parameter value or other modeling techniques to represent an important interface of the grid with the intended new investment. Simulations are then run to examine the economic performance of the new investment.

This approach represents a significant increase in specificity as it addresses a specific EES technology applied in a specific location of a specific grid thereby reducing the speculative nature of the generic approach. However, while such an approach is helpful, it still falls short of what a utility would require to make a credible submission to its regulatory commission for rate base addition of an EES system. More than likely, the installed costs and possibly operating costs of the new device are projected from engineering studies rather than from specific quotes from the device vendor as would be necessary in a rate base submission. In addition, details of the grid around the location of the new investment are masked, to a degree, by the assumptions required to make the models tractable. Finally, such an approach focuses on the economic performance of the device from the point of view of the potential investor primarily concerned about return on investment and thus, less concerned about other value that might be contributed to the grid. In other words, these methods may be mostly applicable in a market, rather than a cost of service regulatory context.

4.2.4 Production Cost Modeling Approach

Eventually, a utility proposing to invest funds in any new technology would want to understand how that proposed addition is likely to perform under realistic operating conditions. Production cost modeling is the professional standard of evaluation that would need to be employed to demonstrate the ability of an EES to contribute to operating effectiveness thereby helping to make the case to the utility commission. It takes into consideration aspects of the other generators on the grid, the transmission network, and the load. It is the most complete evaluation available but is, perhaps, also the most costly. For this reason, it is suggested as a final stage of evaluation after other, less costly methods are applied. These other methods can select a smaller subset of technologies and applications to reduce the number of different simulations necessary in production cost modeling.

It is important to note, however, that production cost models have some important and significant limitations. They are unable to quantify the value of added capacity and thus resource adequacy, specifically from the installation of EES as they generally only look at a 1-year timeframe. This limited timeframe also presents issues in terms of risk, specifically in the form of load and renewables forecasting. A value, for example, for an EES system, associated with a 1-year run may not accurately represent the value of the system in future years.[40] Their use needs to address such issues and be supported by other analyses (such as multiple year and sensitivity production cost runs). Presuming that these limitations are addressed, production cost models are particularly well adapted to the decision space occupied by vertically integrated, investor-owned, regulated utilities.

4.3 Elements of A Regulated Utility Rate Base Submission

It should be apparent from the preceding discussion that evaluating EES should be very similar to, and no more difficult than, the evaluation of other utility investments. EES evaluation starts with the identification of the needs and requirements of the grid at a specific location, then the specification of the technologies that can serve those needs, the quantification of the costs of each technology, and, finally, the calculation of the value streams.[41]

4.3.1 The "Down-Scoping" Process: Identifying Grid Location-Specific EES Functional Uses[42]

One of the main distinguishing features of this evaluation approach is the emphasis on site-specific identification of EES asset deployment. Figure 1 presents the technology characteristics of storage systems (a combination of typical module size, power rating, and discharge time). This graphic provides a general view of where EES technologies fit into the grid.[43] More than likely such specifications would reference a specific bus or substation within the transmission or distribution network.

The term *functional uses* refers to the specific characteristics of technologies that can be used to match grid needs and, for this purpose, must have reference to specific locations of the host grid. Commission staff should expect to see a much more specific identification of these variables in relationship to specific locations in the grid with which they have the responsibility to regulate.

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[40] For more discussion, see EPRI Report on benefits and limitations of modeling tools for energy storage (to be released this year). Also see the Sandia/EPRI Energy Storage Handbook and the Sandia ARRA report.

[41] Because of the modularity of EES systems, the funding required to make an investment may be less upfront and possibly less in aggregate if costs decline, than for other types of investment decisions, thereby reducing certain economic risks.

[42] Eyer and Corey (2010), Rastler (2010), and Rittershausen and McDonagh (2010) use the term ―applications." We prefer the term ―functional uses" because it is more specific to the capabilities of the technology. Eyer and Corey (2010) count 17 applications while Rittershausen and McDonagh (2010) count 12.

[43] A phrase that describes EES and is sometimes used in the literature, limited energy storage resources or LESRs, conveys the clear idea that storage resources have the ability to provide energy or capacity up to the maximum of their stored energy. Applications of EES are determined in part by matching the need for energy or capacity with the ability of different EES technologies to bridge the required duration.

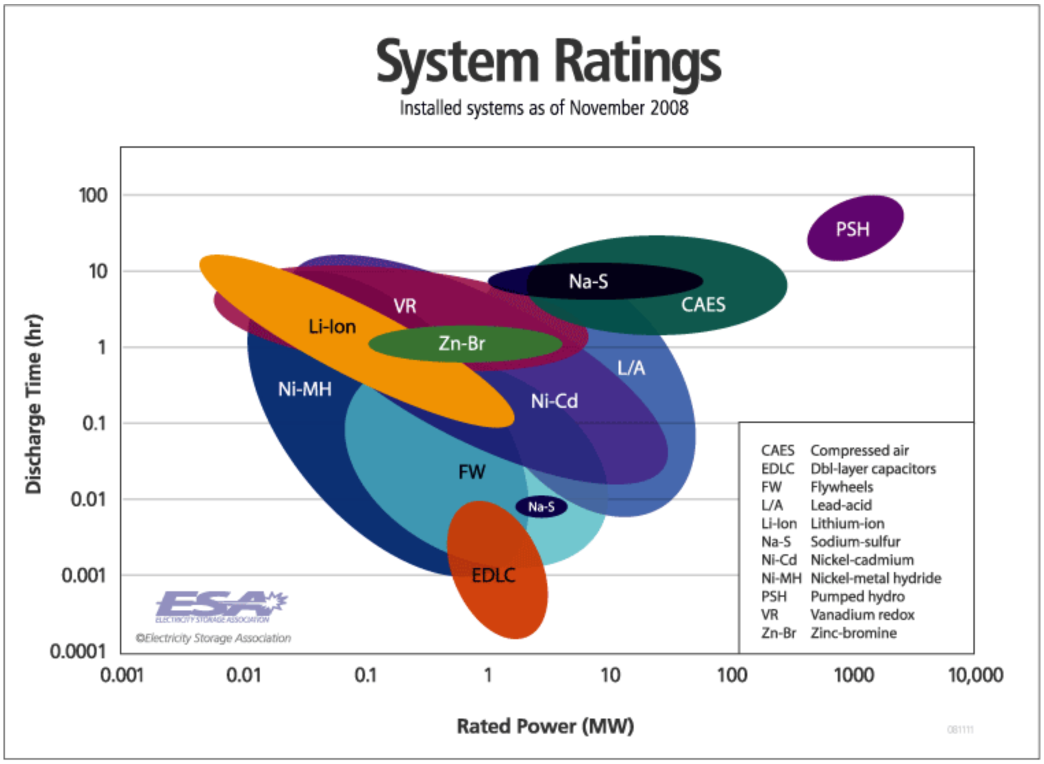

Figure 1: EES technology characteristics arrayed with time[44]

The important considerations in identifying functional uses for EES include the following:

- The status quo (what is currently filling the need)
- A clear use specification
- Potential issues with current solutions
- Technical specifications, including duration of required charge and discharge periods
- The length of time the solution is needed, which affects the cost-effectiveness of the asset

4.3.2 Identification of Benefits or Revenue Streams

The process of identifying functional uses clarifies where the benefits of the storage device accrue in the electric system. This may be different from the physical location of the storage system. For example, an EES located at the end user's location might act as a substitute for overall system peak capacity that is traditionally associated with central generation. The functional uses are based on a match between the engineering or physical characteristics that are required, given the characteristics of the grid, including the other technologies on the system.

A value metric must be identified and associated with each functional use that will translate physical functional use into dollars. This is a necessary step towards the valuing of energy storage systems in

[44] Electricity Storage Association.

comparison to other alternatives. Table 1 presents the functional uses for EES systems and their associated value metrics.

Table 1: Functional uses for EES systems and their associated value metrics.

		Functional Use	Value Metric	Possible Analysis Approaches
Bulk Energy	1	Electric Energy Time-Shift	The price differential between energy price during charge and discharge. This includes: ● *arbitrage* ● *renewable energy firming and integration*	Production cost modeling; optimization using historical and projected data; use specific valuation tools
			● *electric supply capacity:* The avoided cost of new generation capacity (procurement or build capital cost) to meet requirements.	Long term planning models; production cost modeling
T&D	2	Transmission Upgrade Deferral	The avoided cost of deferred infrastructure.	Long term planning models
	3	Distribution Upgrade Deferral	The avoided cost of deferred infrastructure.	Long term planning models
	4	Transmission Voltage Support	The avoided cost of procuring voltage support services through other means.	Power flow modeling
	5	Distribution Voltage Support	The avoided cost of procuring voltage support services through other means.	Power flow modeling
Reserve	6	Synchronous Reserve	*Regulated env:* the avoided cost of procuring reserve service through other means. *Market env:* the market price for synchronous reserve.	Production cost modeling; optimization using historical and projected data; use specific valuation tools
	7	Non-Synchronous Reserve	*Regulated env:* the avoided cost of procuring reserve service through other means. *Market env:* the market price for non-synchronous reserve.	Production cost modeling; optimization using historical and projected data; use specific valuation tools
	8	Frequency Regulation	*Regulated env:* the avoided cost of procuring service through other means. *Market env:* the market price for frequency regulation service.	High resolution production cost modeling; optimization using historical and projected data; use specific valuation tools
Customer	9	Power Reliability	The avoided cost of new resources to meet reliability requirements.	Distribution modeling: power flow; use specific valuation tools; simple internal modeling
	10	Power Quality	The avoided cost of new resources to meet power quality requirements, or avoided penalties if requirements not being met.	Distribution modeling: power flow; use specific valuation tools; simple internal modeling

Different authors count a different number of benefits: Eyer & Corey (2010) count 27 while Rittershausen and McDonagh (2010) identify 22 ―operational uses.‖ Because some uses are not independent, this paper aggregates these into fewer functional uses, in an attempt to eliminate duplication and overlap. These functional uses provide the building blocks for further evaluation.

An EES application is the combination of the distinct functional uses a storage system provides when sited at a specific location and managed in a particular manner. Four factors must be addressed to understand the ability to provide a service at a specific location:

- How would an EES system performing a functional use be operated?
- Where would an EES system performing a functional use be physically located on the electric system?
- What primary requirements drive this functional use?
- What other functional uses could be provided by this system?

The answers to these questions help assess how EES can be practically used to provide simultaneous grid services. The values associated with each individual functional use can vary depending on the interactions within the application.

4.3.3 Application of a Benefit-Cost Evaluation of Alternatives

4.3.3.1 Perspective of the Evaluation

When a regulated, investor-owned utility wishes to invest in an energy storage device, commissioners and their staffs should expect to receive an analysis of the investment in grid assets in the form of a private benefit-cost analysis of the investment. This analysis could take a variety of forms, depending upon the preferred analysis approach of the particular utility presenting the analysis. That said, some key elements should be incorporated. Foremost, the important issue of the perspective of the analysis should be addressed. The commission should expect the regulated IOU to present an analysis from the perspective of their shareholders, with the analysis demonstrating that the investment adds to shareholder value. This would be a private benefit-cost analysis. As such, it would contain evaluations of only benefits and costs as viewed from the utility's perspective. Additional sales of electricity would be evaluated at the regulated rates for the utility, and costs would be accounted from the point of view of the utility. Because rates are regulated, the successful investment would be viewed as a reduction of costs compared to some alternative. This would involve an analysis of at least two alternatives: the ―undertake the project" alternative and the ―do not undertake the project alternative.

With specific grid needs identified, and the EES technologies that can supply those needs also identified as described, a benefit-cost evaluation process can be applied. While it is not the purpose of this report to develop a complete description of all of the issues relevant to the development of a benefit-cost analysis of a private project, a high-level description of the important methodological issues is appropriate and thus provided.

Benefit-cost analysis applied in a private sector context is often referred to as *discounted cash flow* (DCF) analysis (Campbell & Brown, 2003). The methodological principles and techniques of the two approaches are virtually the same. The main difference is that the private analysis focuses exclusively on the revenue and cost (cash) flows that are estimated to result over the lifetime of the project upon its implementation, and does not include public benefits and costs.

Again, this is adopting the perspective of the investor in the EES system.[45] Additional analyses might accompany the investment proposal; for example, if the investor is the utility itself, it will also likely perform a revenue requirements analysis to demonstrate the likely impact of the investment on the need for or lack of need for retail electric rate adjustment. It is likely that a suite of analyses would support the proposal to the commission. A DCF/benefit-cost analysis to demonstrate positive net benefits over the long term, helping to support the capacity adequacy aspect; a revenue requirements analysis to demonstrate retail rate impact, if any; and a production cost modeling exercise to demonstrate operating cost-effectiveness; are all likely components of the analysis suite.

It is possible that the commission, its staff, or an intervener organization will wish to extend this private benefit-cost analysis into a consideration of the public benefits and costs of the project. In that case, much of the relevant information about the project will already be available from the private analysis.

A schematic representing the process of reaching a decision through the application of benefit-cost analysis is contained in Figure 2. This figure represents the allocation of resources to one or the other of two projects where the right hand branch represents alternatives (including continued use of current technologies). The do nothing alternative should always be present in project comparisons. Independence between the benefits and costs of the projects is normally assumed. If independence is not the case in a particular application, then additional alternatives must be devised that are comprised of a combination of the interdependent projects. Incremental benefits and costs must then be calculated for the combined alternative. The effect of the process described in Figure 2 is to apply the economic concept of opportunity cost. If resources are assumed scarce, the cost of action A is the net revenue that could have been earned from applying the resources to action B instead. Other references on benefit-cost analysis include Hendrickson and Matthews (2011) and Newnan, Eschenbach, and Lavelle (2012).

[45] The investor in an EES system proposed by a regulated utility could be the utility itself, an IPP proposing an EES investment the output of which is sold to the regulated utility (under a PPA), or a merchant plant.

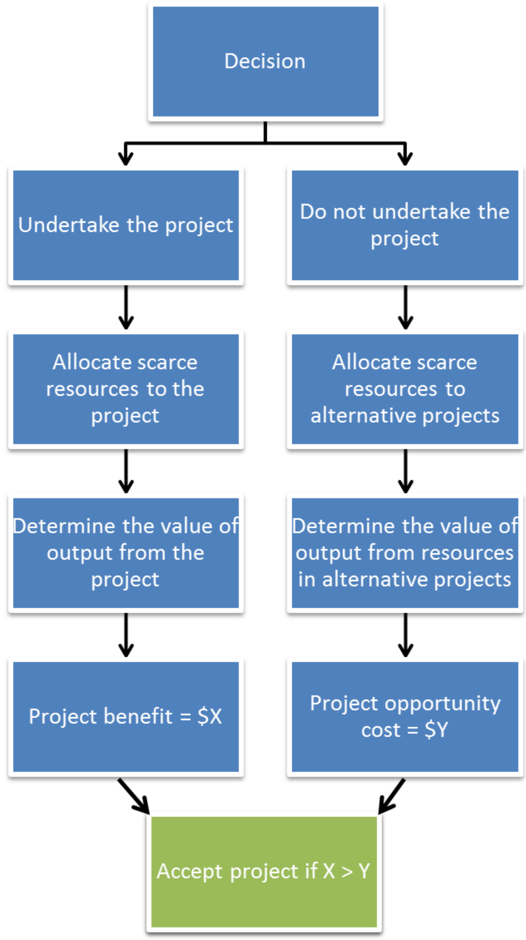

Figure 2: Benefit-cost analysis using the concept of opportunity cost.[46]

A variety of investment criteria can be used in the discounted cash flow methodology. These include internal rate of return (IRR) which is the rate of return that equalizes the present value of benefits and costs; the rate of return on equity capital of the entity proposing the project; or, the net present value (NPV), which is the present value of benefits minus the present value of costs. Any one of the criteria can be used and often several or all of the criteria will be calculated and used in conjunction, for a thorough analysis.[47] The Appendix contains two cases that demonstrate this process with the application of the net present value criterion to an evaluation of two hypothetical EES investments. In these cases, only the net present values are calculated.

4.4 Externalities Associated with Use of EES Technologies

EES technologies can reduce system costs by permitting conventional generators to operate at their most efficient level. Currently, operators of conventional generators typically hold back some of their capacity and use it to provide services for grid operations (ancillary services in market areas). If EES systems

[46] Adapted from Campbell and Brown (2003).

[47] The Sandia ARRA report has a further discussion of the various investment criteria and a recommendation of the appropriate criteria depending on the situation.

replace this reserve capacity and provide ancillary services to reserve markets, thereby allowing conventional generators to operate at their most efficient set point, an external benefit is provided to the system and to specific generator owners that the owners of the EES systems have no means to appropriate.

Reduction of air emissions from electricity generation is a potentially important incidental benefit of EES. If EES systems are used to provide grid services, allowing conventional generators to operate at their most efficient output level, less fuel is used per unit of output, which lowers both fuel costs and emissions. Due to lower nighttime temperatures, generators used to charge storage will operate more at night when fuel efficiency is higher and emissions output is lower. Finally, because energy to charge storage is transmitted at night when ambient temperatures, and transmission and distribution (T&D) loading are relatively low, T&D energy losses are reduced relative to those that would be incurred if that energy were transmitted during the day. Implementation of a cap and trade program or a carbon tax may change the relative economics of energy storage systems by quantifying this benefit.

In many situations, the use of energy storage will increase the amount of electricity that is generated and/or transmitted and/or distributed using existing utility assets. The effect is commonly referred to as *increased asset utilization*. Two important implications of increased asset utilization are:

- The cost to own the equipment is amortized across more (units of) energy generation and/or transmission and/or distribution, which reduces the capacity-related portion of unit cost for that energy.
- The payback from the investment (in the respective utility capacity asset) occurs sooner, which reduces investment risk and increases capital efficiency.

Consider an example: A utility installs distributed energy storage to address local electric service reliability needs and to defer an expensive T&D upgrade. Energy storage use increases generation asset utilization if the storage is charged using existing generation assets, during times when demand is low. Similarly, transmission asset utilization increases if existing transmission capacity is used to transmit the energy to charge storage (presumably, transmission occurs during times when transmission asset utilization is normally low). Depending on location, distributed energy storage may also increase distribution asset utilization.

There may also be negative externalities associated with EES systems. The production of EES systems, depending on the type of technology, the raw materials needed, and the harvesting process, could present environmental issues in the form of emissions from energy use, habitat destruction, or water contamination. Additionally, many of the EES battery technologies involve toxic chemicals, from lithium in lithium-ion systems, to lead in lead acid systems, which unless properly recycled and disposed, may present end-of-life environmental issues. The installation of pumped hydro or CAES systems may result in habitat destruction. There may also be safety issues involved with the use of EES systems. With batteries, there is a potential for overheating and fire or explosion, not only presenting a safety risk, but also an environmental issue with the release of toxic fumes. There is also the potential for leakage of toxic battery components.

That said, with proper protocols in place, these issues can be addressed, and if so, the benefits and positive externalities associated with EES systems have the potential to outweigh the negatives.

5 Concluding Observations

The present state of the regulated utility environment for electrical energy storage system deployment has been discussed in this report to provide state utility regulators an understanding of how energy storage systems can be considered an electric grid asset.

This review includes the definition of utility owned EES, the identification of grid applications for EES, and the factors affecting the future grid that may affect the deployment of EES. Brief descriptions of the various EES technologies are provided along with the factors affecting demand for EES and references to summary cost information for each. In addition, the current deployments of EES within the forty-eight contiguous states are discussed. Current dockets referencing various levels of review and approval for EES are summarized and the main advantages, disadvantages, and challenges for energy storage systems are identified.

Much of the literature about energy storage systems has sought to portray them as unique, endowed with a wide array of potential benefits; however, it is claimed to be difficult to determine how they can be evaluated and where they are most useful. This report has attempted to cut through some of this complexity in order to emphasize the essence of energy storage systems. Hopefully this approach will help to make energy storage systems more appealing from a technological, economic, and regulatory standpoint and therefore more likely to be deployed.

The one feature that makes these systems unique—their ability to store energy— also puts them in direct economic competition with load, or more properly, demand response. Not only do storage technologies face competition from every technology on the supply side but also competition from those on the demand side. Thus, the main present challenges to increased deployment have to do with economic comparisons—can energy storage systems deliver their services at lower cost than competing technologies? Public utility commissioners faced with decisions regarding such technology deployments will ultimately make their decisions based on protecting the interests of their constituents: do these technologies help to protect electricity consumers from unnecessary increases in electric rates.

Trends in the industry may help to further the deployment of energy storage systems. Clearly increased penetration of renewables is one such trend. The increased ―peakiness" of load and declining inertia on the system may also provide opportunities. Furthermore, the relatively small scale of most energy storage technologies (pumped hydro and CAES excepted) should provide many opportunities for deployment. Thus, a deployment strategy emphasizing the appropriate technology and scale to provide distribution system and near-to-consumer deployment can be cost-effective, and provide grid support indirectly, while at the same time, buy time for further (cost-reducing) technology development of larger energy storage technologies. The following are among the most important takeaways from this analysis:

- Electric Energy Storage systems (EES) have the potential to play a major role in the current and future electricity grid;
- The value contributed by EES is judged by the cost of the next best alternative means of providing the service;
- EES systems have a unique feature in their ability to store energy;
- Vertically integrated utilities may have an advantage in their ability to internalize all of the benefits available from energy storage technologies although this probably cannot be conclusively demonstrated and may depend on organizational structure and possibly other characteristics. Unfortunately, these benefits are valued at cost (of the next best alternative) as opposed to values based on revenues derived from market transactions as they would be in a market environment;

- Asset classification issues can be clarified by viewing the systems from the point of view of the services they perform rather than their inherent engineering characteristics;
- The regulatory environment may make it difficult for utilities to propose such systems; regulatory commissions may need to work with utilities to facilitate deployment;
- Establishing a framework for evaluating EES and their alternatives, as provided in this report, may help increase deployment by aiding utilities in proposing, and regulatory commissions in evaluating, energy storage systems;
- Phase-in tariffs or other incentives might provide the necessary financial incentives to induce utilities to invest in EES in the absence of carbon pricing.

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Appendix

1 Electricity Storage Technology

In simplest terms, electricity storage involves two processes: storing electrical energy (charging), and releasing electrical energy (discharging). To make energy storage profitable, electricity is purchased at a low price for charging and sold at higher prices while discharging. Thus, energy storage functions on the principles of financial arbitrage.

1.1 Physics of Electricity Storage

For electricity related applications, energy storage involves conversion of electricity to or from potential gravitational energy (pumped hydro), kinetic energy (flywheels), pneumatic pressure (CAES), and electrochemical charge (batteries and capacitors).

Pumped hydroelectric plants store energy by pumping water up to a higher elevation, converting the electrical energy to potential energy. When electricity is required, this water is allowed to return to a lower level, through a turbine generator that converts the potential energy back to electricity.

Flywheels store electricity in the form of kinetic energy, increasing the velocity of a spinning mass via a reversible motor-generator (the energy stored using a flywheel can be referred to as rotational energy). When electricity is needed, the reversible motor-generator reduces the kinetic energy of the spinning mass by applying a load, slowing it down, and thereby generating (or, in effect, discharging) electricity.

Storing electricity via pneumatic pressure in CAES is done using the compression of air in a constrained space. The constrained space typically includes high-pressure pipes, tanks, or underground geologic formations (generally an aquifer or salt dome). Electric power is used to compress the air during charging phase. Power is generated as the compressed air is expanded in a turbine generator.

Electrochemical storage involves electrochemical reactions that are used to store and discharge energy. The reactions absorb electrons (e.g., current from the grid) to store energy by plating reducing ions and plating them onto an electrode surface. Energy is released when a load induces the reverse reaction. Electrons are released as the plated atoms are oxidized, providing current, and thus electricity. The reactions occur within a cell, these cells are grouped into batteries, and batteries are grouped, as needed, to provide the necessary scale.

Electricity can also be stored in the form of electrostatic charge in a device called a capacitor. Energy is stored by the accumulation of charge on an electrode surface within the capacitor. A capacitor is charged when current is provided so that its two plates have opposite charges, creating an electric field. When electricity is extracted, the opposite charges equilibrate, in effect releasing electrons to create an electric current.

1.1.1 Electricity Storage Plant Primary Rating Criteria: Energy and Power

The two primary storage plant-rating criteria are capacity and energy. *Capacity* indicates the instantaneous energy available from the storage system. Instantaneous energy is also referred to as power, thus capacity can be interchanged with power or power capacity. *Energy* specifies the total amount of energy that a storage system can store, or alternatively, discharge from its full state.

The capacity, or power rating, is expressed in static units of kW or MW. Energy rating is usually expressed in units of kilowatt-hours (kWh) or megawatt hours (MWh). These units allow for an easy understanding of a storage system, as another important plant rating criteria is discharge duration, which represents the length of time a storage device can be continuously discharged at its rated capacity. Thus, the energy rating equals the capacity multiplied by the discharge duration or MW multiplied by hours gives MWh.

1.1.1.1 Storage Plant Performance Criteria

Round-trip Efficiency – Round-trip efficiency indicates the amount of usable energy that can be discharged from a storage system relative to the amount of energy that was put in. This accounts for the energy lost during each charge and discharge cycle due to mechanical, electrochemical, or electronic losses. Typical values range from 60% to 95%.

Response Time – Response time is the amount of time required for a storage system to go from standby mode to full output. This performance criterion is one important indicator of the flexibility of storage as a grid resource relative to alternatives. Most storage systems have a rapid response time, typically less than a minute and are typically very accurate in reference to signals received. Pumped hydroelectric storage and compressed air energy storage tend to be relatively slow as compared with batteries and flywheels while capacitors tend to have a relatively fast response time.

Ramp Rate – Ramp rate indicates the rate at which storage power can be varied. A ramp rate for batteries and flywheels can be faster than 100% variation in one to a few seconds. The ramp rate for pumped hydroelectric storage and for compressed air energy storage is similar to the ramp rate of conventional generation facilities.

Energy Retention or Standby Losses – Energy retention time is the amount of time that a storage system retains its charge. The concept of energy retention is important because of the tendency for some types of storage to self-discharge or to dissipate energy while the storage is not in use. In general, terms, energy losses could be referred to as parasitic or standby losses.

1.1.1.2 Other Storage Plant Characteristics

Energy Density – This criterion specifies the amount of energy that can be stored for a given amount of area, volume, or mass. Energy density varies significantly, by a factor of three or more for the spectrum of energy storage technologies. This criterion is important in applications where area is a limiting factor, for example, in an urban substation where space could be a limiting constraint to site energy storage.

Power Density – Power density indicates the amount of power that can be delivered for a given amount of area, volume, or mass. In addition, like energy density, power density varies significantly among storage types. Again, power density is important if area and/or space are limited or if weight is an issue.

Safety – Just as for all other electric equipment, safety is an important consideration for energy storage systems. Safety is related to both electricity and to the specific materials and processes involved in storage systems. As an example, flywheel storage uses a heavy spinning mass that could cause severe injury in the case of failure; pumped hydroelectric plants use upper reservoirs, which could result in dangerous flooding if they were to break; and the chemicals and reactions used in batteries can pose safety or fire concerns.

1.2 Electricity Storage Types

This section discusses the different electricity storage technologies.

1.2.1 Pumped Hydroelectric Storage

Pumped hydroelectric storage (commonly referred to as pumped storage hydro, pumped hydro, or pumped storage) consists of a lower and an upper reservoir, the latter being located at a higher elevation. Energy is stored by purchasing less expensive electricity to pump water from the lower reservoir to the upper reservoir. Energy is recovered by allowing water in the upper reservoir to return to the lower reservoir through a turbine-generator (similar to those used for conventional hydroelectric generation).The advantage provided by such a system is to time-shift electric energy production to times when it is more in demand (more expensive).

Pumped hydro is a mature and fully commercialized technology with about 21.5 GW of pumped hydro capacity in the U.S. and over 100 GW worldwide. Notable PSH plants in the U.S. include:

- The 240-MW Lewiston PSH plant near Niagara Falls, New York owned by the New York Power Authority.
- Pacific Gas and Electric Company owns the 1,050 MW Helms PSH plant located in Fresno County, California.
- The City of Los Angeles owns the 1,275 MW Castaic PSH plant. A facility that is part of the California Aqueduct Project.
- The Raccoon Mountain PSH plant, owned by the Tennessee Valley Authority, generates 1,530 MW.
- The 2,772 Bath County PSH in the Alleghany Mountains is owned by Dominion and the Allegheny Power System.

Important features of pumped storage hydro include:

- Mature and fully commercialized technology.
- Low incremental cost for additional energy storage.
- Nearly immediate start-up, much faster than fossil-fueled thermal generation.
- Limited number of locations, considering water and siting-related restrictions and transmission constraints as well as high initial capital cost.

1.2.2 Compressed Air Energy Storage

As mentioned above, CAES involves compressing air that will be used to generate electricity when needed.

For conventional CAES designs, to improve the efficiency of the process, the air is preheated before expansion using natural gas fired heaters and then sent through the turbine, which turns a generator to generate electricity. Typically, to improve the efficiency of the process, the air is preheated during expansion using natural gas fired heaters.

Adiabatic CAES (A-CAES) is a newer CAES concept that eliminates the need to burn natural gas when compressed air is released during storage discharge. Air is preheated during the discharge (expansion) phase by heat exchange with the hot air that is a product of the charge (compression) phase as energy is being stored. This avoids the use of polluting natural gas and increases the efficiency of the system. However, this process is still in its research phase with no demonstrations outside of the laboratory.

For larger CAES plants, compressed air is stored in underground geologic formations, such as salt domes, aquifers, and depleted natural gas fields. For smaller CAES plants, compressed air is stored in on-site tanks or pipes (above or underground) designed for high-pressure applications.

Most of the component machinery and equipment used for CAES is fully commercialized. Conventional CAES has been demonstrated as a large-scale asset. Two commercial plants are in service and others are in planning and design. The two plants in commercial operation include one at Huntorf, Germany, rated at 290 MW, and the other at McIntosh, Alabama that is rated at 110 MW. Lately, A-CAES and small above ground CAES are receiving attention.

Key features of CAES include:

- Subsystems are mature and represent fully commercialized technology.
- Low to medium incremental cost for additional energy storage.
- Comparable performance to fossil-fueled thermal generation.
- Requirement for fuel, usually natural gas for —Conventional" CAES.
- Limited number of locations, considering geology and siting-related restrictions and transmission constraints for traditional CAES systems.

1.2.3 Flywheel Energy Storage

Flywheel electric energy storage systems (FEES) are comprised of a cylinder or wheel attached to a shaft within a robust, evacuated enclosure. In some systems, a magnet levitates the cylinder; thus, limiting friction-related energy losses and wear. The shaft is connected to a motor/generator. Electric energy is converted to kinetic energy by increasing the flywheel's rotational speed. The stored kinetic energy is converted back to electric energy by applying a load via the motor/generator, slowing the flywheel's rotational speed and thus generating electricity. High-speed flywheels spin at rates from 10,000 to 20,000 RPM. Flywheels are becoming a commercial technology by virtue of commercial-scale applications in New York and demonstration projects in a number of other locations.

Key features of flywheels include:

- Mature subsystems that constitute a fully commercialized technology.
- Very rapid ramp and accurate response to signals make this technology ideal for frequency regulation.
- Flexibility in siting considerations constitutes a distinct advantage for FESS technology.
- Frequent charge/discharge cycles for this technology.

1.2.4 Electrochemical Batteries

Electrochemical batteries (batteries) involve chemical reactions for storing and discharging electric energy. Numerous battery chemistries exist, including common ones such as alkaline, lead-acid and nickel metal hydride. A battery is a device comprised of more than one interconnected galvanic cell within which chemical reactions occur. Cells are comprised of three fundamental elements: a) the anode (the negative terminal), b) the cathode (the positive terminal), and c) the electrolyte, a material that conducts electricity.

Key features of electrochemical batteries include:

- Limited life due to limits on the charge/discharge cycles.
- Most suitable for stored energy for peak shaving and similar applications.
- Relatively costly because first cost and frequent replacement involve capital cost expenditure.
- New technologies and chemistries that show great promise and potential for expansion of battery deployment.

1.2.5 Flow Batteries

Most electrochemical batteries are self-contained so that the electrolyte is in the same vessel as the cells wherein the electrochemical reactions occur. Flow batteries use electrolyte stored in separate containers. In flow batteries, the reactive material is in solution instead of in solid plates as with the lead-acid battery. Energy and capacity are decoupled and can be sized separately. When flow batteries are charging or discharging, the electrolyte is pumped between the electrolyte containers and the cell stack.

The commercial status of flow batteries may be described as near commercial. Several flow battery technologies have undergone significant development and some have been deployed. Development of flow batteries is increasing and fully commercial products are in the field.

Largely, flow batteries operate much like electrochemical batteries. A key advantage to flow batteries is that the storage system's discharge duration can be increased by adding more electrolyte (and, if needed to hold the added electrolyte, additional and/or larger electrolyte containers). It is also relatively easy to replace a flow battery's electrolyte when it degrades.

1.2.6 Summary Statement on EES Technology Characteristics

Technology development among EES is very dynamic and progress is being made along all technology fronts affecting the scale, discharge duration, efficiency, response time, ramp rate, cost, and commercial maturity of most of the technologies. This dynamic situation leads us to direct the interested reader to other sources where this information is more regularly reported and updated. References to published reports are presented in the references section. Other internet sources include the following:

- http://www1.eere.energy.gov/vehiclesandfuels/technologies/energy_storage/index.html
- http://storagealliance.org/about.html
- http://www.sandia.gov/ess/
- http://energyenvironment.pnnl.gov/ei/energy_storage.asp
- http://www.nrel.gov/vehiclesandfuels/energystorage/publications.html

1.3 Other Engineering Features of EES Systems

Electricity storage technologies vary over a considerable capacity range; units combined in a plant configuration can achieve a wide range of scale. Typically batteries and flywheel energy storage range from kW to single digit MW size. Underground CAES can be quite large (tens to hundreds of MW) while above ground CAES, though smaller, can be optimally sized. To achieve large plant sizes these storage technologies could be configured in multiple-unit plants. Given the modular nature of some storage types, it is practical to build transportable storage systems. Transportable energy storage may be attractive for several reasons:

- Transportable storage can be deployed when and where needed.
- More storage can be easily added if needed.

1.4 Average EES Device Costs

Several excellent reports have recently examined EES technologies in detail, including the extent of maturity for each technology, the most suitable applications for each, and the performance of each technology in different applications. One report develops the estimated costs for various EES systems in their most advantageous applications using current costs as supplied by vendors. The cost estimation methods and assumptions are detailed in each report. Due to the wide availability of those reports and the complexity of the various calculations and evaluations, we do not repeat the results here. The review of each of these reports will provide the reader a rich perspective on the technologies, their state of development maturity, their most suitable grid applications, and the estimated costs of capacity and energy produced by each.

The following reports provide this information:

- Eyer, J., & Corey, G. (2010). Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide. (SAND2010-0815). Albuquerque, NM: Sandia National Laboratories.

- Rastler, D. (2010). Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits. Palo Alto, CA, Electric Power Research Institute.

- A. Akhil, "DOE/EPRI 2012 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association," Sandia National Laboratories, Albuquerque, NM. Expected November 2012.

2 Deployment of Electric Energy Storage

2.1 Current Status

2.1.1 Conventional and Pumped Storage Hydro

Deployment of energy storage technologies through recent U.S. history and up to the present is mostly the story of hydroelectric and pumped storage facility development. Many hydro projects, particularly, those in the Rocky Mountain West were built with public funds and multipurpose justifications including flood control, irrigation, water supply, recreation, and power generation. The power generation purpose is served through the federal marketing agencies of Western Area Power Administration (WAPA) and Bonneville Power Administration (BPA), both of which are institutionally constrained to market largely to municipal utilities, irrigation districts, rural electric coops, and so forth.

Despite the relatively large installed base, the likelihood of new conventional hydro projects is limited due to high capital costs and environmental opposition, among other factors. Some pumped storage hydro projects have been developed with private capital, but topological and capital cost factors are limitations to further deployment. Pumped storage facilities are perhaps a more likely hydroelectric option. Permitting and approval times—often consuming more than a decade—will need to be streamlined in order for this option to become viable. The FERC website identifies the project locations of already licensed, pending licenses, preliminary permits, and pending preliminary permits for pumped storage facilities.[48] Some European countries are investing significantly in pumped storage hydro projects and it is expected that by 2020 more than 60 new pumped hydro projects will be constructed with an installed capacity of 27GW.[49] New conventional hydro capacity beyond incremental changes due to turbine improvements is likely to be limited.

2.1.2 Other Storage Technologies

Meanwhile, other storage technologies—namely batteries, flywheels, and compressed air—are the focus of a resurgence of interest and significant technology development. The resurgence of interest may be explained partly by the renewable portfolio standards that many states have adopted, driving a surge of investment in renewable energy. Additionally, tax incentives offered by some states and the federal government play into this resurgence. Variability of generation from wind and solar may establish a niche where storage technologies can come to the forefront and play a constructive and profitable role.

Unfortunately, grid scale industry experience with these technologies is limited. Again, due to the dynamic nature of project development we provide the reader a link where the most recent, updated information can be obtained.[50]. Technology diffusion may be most significant for batteries with possibly up to ten or so commercial scale applications. However, some of those deployments may be on the customer side of the meter. Flywheel deployment has begun with the Beacon Power facility in the NYISO area. As experience with this facility accumulates, it may help to boost the diffusion of flywheels. The only compressed air facility in the U.S. is the Norton Energy Storage facility in Alabama. This facility has

[48] ~~"~~FERC: Hydropower – Pumped Storage Projects." Federal Energy Regulatory Commission. Updated May 2, 2012. http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp.

[49] ~~"~~The European Market for Pumped-storage Power Plants." ecoprog GmbH. Cologne. March 2011. http://www.ecoprog.com/en/publications/energy-industry/pumped-storage-power-plants.htm.

[50] http://www.sandia.gov/ess/project_map/index.html

been in operation since the early 1990s and therefore should have generated enough actual experience with the technology to answer industry questions about technology practicability.

2.1.3 American Recovery and Reinvestment Act Projects (ARRA)

The US Department of Energy has funded a number of EES projects throughout the United States to demonstrate the potential for energy storage systems to contribute valuable electric grid services. While these projects have not been subjected to the normal approval and evaluation processes they can provide valuable information and data required to assess the potential of specific applications of EES.

3 Case Studies: Energy Storage Proposals

The case studies presented here are based on the framework presented by Southern California Edison in their report on energy storage (Rittershausen & McDonagh, 2010). This work has been modified and expanded into a more comprehensive example following the evaluation process presented in Section 4 of this report in order to provide regulators with a clear framework to evaluate energy storage systems.

3.1 Case Study 1: Renewable Energy Shifting and Firming

Considering that renewable energy penetration may increase significantly in the near term, and that most of this will likely be in the form of intermittent wind and solar resources, the integration requirements and costs to the system are expected to be significant. As outlined in this report, resources, such as EES systems will be necessary to address these requirements.

Thus, it is reasonable to expect that in the near future, a utility will submit a storage system for rate base consideration with its purpose being to shift off-peak energy to on-peak, thereby firming the intermittent energy provided by a renewable energy resource. Note that these are not separate activities: energy arbitrage, and simultaneously, providing firming.

3.1.1 Functional Uses

An EES device will be located at the generation site of an 80 MW wind farm. This wind farm produces a significant amount of its energy during the nighttime, as is the case with wind production in West Texas and in Denmark. The energy storage system will be charged off-peak and discharged on-peak to make this wind farm an on-peak dispatchable, firm resource. It is assumed that the wind farm and associated energy storage system will be owned and operated by a regulated utility. The regulated utility will need to submit a rate base case to its state public utility commission to recover costs for this system. A discounted cash flow (private perspective benefit-cost analysis) evaluation for such a system would be included among the documents submitted to support the request.

Monetary benefits and avoided costs include:

1) Resource Adequacy (RA) and dependable operating capacity: Wind energy, being an intermittent energy source cannot provide its nameplate capacity for resource adequacy or dependable operating capacity purposes. By using an EES system to firm output, RA and dependable operating capacity could be provided.

2) Intermittent energy firming: An EES system can firm the intermittent energy as is otherwise provided by a wind farm and transform the system into a dispatchable resource. The EES system would also smooth the generation output from the wind farm, both on and off-peak. This would be in the form of ramp rate control, significantly reducing curtailment of the resource and easing the need for other, potentially more expensive, resources to provide this service.

3) Energy shifting / wholesale price arbitrage: Lower value off-peak energy can be shifted and sold at on-peak prices.

3.1.2 Required Technology Characteristics

There are a number of different EES technologies, all of which have different technical performance, operational, and cost characteristics that need to be considered. In order to choose the optimal technology that will perform best under the above conditions and best serve the required application, necessary technology characteristics need to be explicitly defined:

- *High-energy output: necessary for long-term on-peak discharge.*
- *High-power output: high capacity necessary to supplement wind.*
- *Moderate charge/discharge frequency: a few charge-discharge cycles may be required over a day.*
- *High depth of discharge capability: For arbitrage, the system needs to be able to release most of its energy.*
- *No limitations on site implementation: Since the system will be located with a wind farm, size issues, permitting issues, T&D connection issues, and other obstacles are unlikely to be important considerations for this installation.*

Depending on the typical daily profile of the wind output at the wind farm, and a firm capacity factor that needs to be met, this requirement will lead to a specific power rating. In this case, an EES system of 20 MW is assumed.[51] It will also be assumed that at least six hours of daily discharge will be necessary to firm the output of the wind farm by shifting off-peak energy to on-peak. Thus, this system will need to provide 120 MWh of energy storage.

These requirements are within the range of what a battery EES system could provide. The power requirement is too low to consider pumped hydro and probably too low for a typical compressed air energy storage system. Therefore, a battery system would likely be the optimal choice.[52]

In this case, a 20MW/120MWh Li-Ion storage system has been selected as the optimal option. The high depth of discharge requirement effectively eliminates Lead-Acid batteries and their new advanced derivatives. Other options that could be considered would include Sodium Sulfur (NaS) and various flow batteries. Ideally, a utility would conduct a performance-cost analysis to determine the best choice.

In this case, the Li-Ion storage system is chosen due to its high-energy storage capability and its relative maturity as a storage technology. Additionally, Li-Ion systems have the ability to undergo a high depth of discharge without significant deterioration in operating life. The relatively small discharge frequency also presents no issues, direct O&M costs are limited, and since other limitations, such as size, safety in confined quarters, or other specific requirements are not an issue, the Li-Ion option will serve this functional use.[53]

3.1.3 Discounted Cash Flow Analysis Assumptions

In order to conduct the benefit-cost analysis, the following assumptions were used for both benefits and costs. These are in addition to the general assumptions discussed above.

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[51] In a complete evaluation, an EES system would need to be sized considering wind output data and would likely involve modeling economic considerations.

[52] There may be other options not considered here, such as aboveground CAES, or micro pumped storage.

[53] Additional detail about Li-Ion batteries is provided in the appendix.

3.1.3.1 Monetary Benefits and Avoided Costs Assumptions

- Capacity procurement costs are based on market prices for electricity trades in CAISO.[54]
- Capital costs for additional capacity were estimated at $71.82/kW-yr. in fixed costs to build a combustion turbine.[55]
- The integration adder for wind used in this analysis is $4/MWh.[56]
- The on peak and off-peak price differential is assumed to be $25/MWh. This value will vary significantly with system location, time of the year, and other factors.
- Benefit values will be escalated 2% annually.

3.1.3.2 Costs Assumptions

- 15 year life for Li-Ion System
- $200,000 annual O&M costs
- O&M escalation 2% annually
- 30% ITC (Federal Investment Tax Credit)
- 0% salvage value
- Total system cost of ***$3,500*** / kW: 40% installation (site preparation, power conditioning system, controls, etc.) and 60% battery capital[57]

3.1.4 Discounted Cash Flow Analysis Calculations

The assumptions detailed above are used to conduct the following discounted cash flow benefit-cost analysis. They are made explicit in the benefit and costs calculation sections.

3.1.4.1 Monetary Benefits and Avoided Costs

The benefits evaluated for this case are: 1) resource adequacy and dependable operating capacity; 2) intermittent energy firming; and 3) energy shifting/wholesale price arbitrage. It must be mentioned that not all of the benefits of an EES system are necessarily compatible. The benefits an EES system can serve depend upon the situation. A utility, knowing all of the details, and having the operating data for its system, should be able to determine and estimate the value of applicable benefits.

The specific assumptions used to make the benefit value calculation are provided in

[54] EIA Wholesale Market Data http://www.eia.gov/electricity/wholesale/index.cfm Averaged CA SP 15 & SP 15–EZ (2007-2011)

[55] E3: Energy + Environmental Economics. ―CPUC Avoided Cost Workshop" PowerPoint presentation for CPUC forum on June 30 and July 31, 2004.

[56] *2012 Transmission and Ancillary Service Rate Schedules General Rate Schedule Provisions (FY 2012-2013)*, Bonneville Power Administration, 2011.

[57] 70% of difference between minimum and maximum estimate for Li-ion system from Rastler (2010).

Table 2 and Table 3 below.

Table 2: Value estimates used in calculations for case study 1

Value Assumptions	
Capacity Procurement Cost [$/kW]	$52.28
Additional Capacity Cost [$/kW-yr.]	$71.82
Wind Integration Adder [$/MWh]	$4
Average On-Peak and Off-Peak Price Spread [$/MWh]	$25.00

Table 3: EES and RE system performance characteristics for case study 1

System Assumptions	
Battery Capacity [MW]	20
Battery System Efficiency [%]	90%
Wind Farm Maximum Capacity [MW]	80
Wind Farm Firm Capacity (w/Battery) [MW]	32
System Lifetime [years]	15

The following table (Table 4) specifies assumptions about each individual benefit and the calculation to determine the value of that benefit, in order to determine a total value of the EES system on an annual and one-time basis.

Table 4: Benefit value specifications for annual and one-time bases for case study 1

Benefit Value Calculation		
1	**Resource Adequacy and Dependable Operating Capacity (per year)**	**$1,672,960**
	avoided cost of new generation capacity (open market procurement) to meet RA or dependable operating capacity requirements	
	Value = Capacity Procurement Cost X Wind Farm Firm Capacity (w/Battery)	
2	**Intermittent Energy Firming (per year)**	**$840,960**
	avoided costs of having to operate the electric grid with an intermittent resource and the premium returns associated with a firmed renewable resource	
	Value = Wind Int. Add X 30% Cap Factor Wind w/o Battery X Wind Max. Capacity X 8760 hrs.	
3	**Energy Shifting/Wholesale Price Arbitrage (per day)**	**$1,800**
	the price differential between off-peak and on-peak prices minus any efficiency losses associated with the charging and discharging process	
	Assumed that 20 MW shifted for 4 hours daily. *Value = Avg. On and Off-Peak Price Spread [$/MWh] X System Efficiency X 20 MW X 4 hours*	

Annual Benefit Value		
Annual Benefits		
1	**Resource Adequacy and Dependable Operating Capacity**	$1,672,960
2	**Intermittent Energy Firming**	$840,960
3	**Energy Shifting/Wholesale Price Arbitrage (300 days)**	$540,000
	Total	**$3,053,920**

3.1.4.2 Costs

Determining lifetime system costs is a relatively straightforward exercise. The same process that is used for other capital improvements can also be applied to EES systems as long as the appropriate assumptions are taken into account. A simplified evaluation breakdown is presented below.

3.1.4.3 Investment Criterion: Net Present Value

Benefits are added together as presented above. The initial and yearly costs are identified and any applicable investment tax credit (ITC), or other incentive, is applied. Lifetime is also specified and double declining balance depreciation is applied. Table 5 below presents the fundamental performance and economic assumptions used in the NPV calculation shown in Table 6 as a simple 15-year net present value calculation for this system.

Table 5: Performance and economic assumptions used in NPV calculations for case study 1

System Size [MW]	20
System Cost [$/kW]	$3,500
Equipment Capital	$42,000,000
Installation Capital	$28,000,000
Investment Tax Credit	30%
Total Capital Investment	$49,000,000
Salvage Value	-
Clean-up Costs	-
Yearly O&M	$200,000
Lifetime (n)	15
Discount rate (i) [58]	7.4%
Yearly Benefit	$3,053,920
Benefit & Cost Escalation Factor	2%
Marginal Tax Rate	35%

[58] 7.4% is the cost of capital as utilized by the *Energy Information Administration* in its Annual Energy Outlook for 2012.

Table 6: DCF Analysis: EES revenues, costs, and NPV by year for case study 1

Year	Capital Cost	Operating Costs	Gross Revenue	Net Revenue[59]	Present Value of Net Revenue	Total Present Value
0	($49,000,000.00)					(49,000,000)
1		($200,000)	3,053,920	2,853,920	2,657,281	2,657,281
2		($204,000)	3,114,998	2,910,998	2,523,675	2,523,675
3		($208,080)	3,177,298	2,969,218	2,396,786	2,396,786
4		($212,242)	3,240,844	3,028,603	2,276,277	2,276,277
5		($216,486)	3,305,661	3,089,175	2,161,828	2,161,828
6		($220,816)	3,371,774	3,150,958	2,053,132	2,053,132
7		($225,232)	3,439,210	3,213,977	1,949,902	1,949,902
8		($229,737)	3,507,994	3,274,200	1,849,571	1,849,571
9		($234,332)	3,578,154	3,316,818	1,744,549	1,744,549
10		($239,019)	3,649,717	3,360,287	1,645,635	1,645,635
11		($243,799)	3,722,711	3,404,626	1,552,467	1,552,467
12		($248,675)	3,797,166	3,449,852	1,464,702	1,464,702
13		($253,648)	3,873,109	3,495,983	1,382,018	1,382,018
14		($258,721)	3,950,571	3,543,036	1,304,114	1,304,114
15		($263,896)	4,029,583	3,591,030	1,230,707	1,230,707
Total	0.00					**($20,807,355)**

[59] Net revenue includes operating costs, gross revenue, taxes, and depreciation.

3.1.5 Discounted Cash Flow Analysis Results and Summary

The total net present value for this system amounts to negative $20 million. Based on this analysis the project is not cost-effective. There would need to be a reduction in system costs, or an increase in benefit value for the project to obtain cost-effectiveness. This analysis does not aim to discuss all of the merits and potential for this application. Evidently, with these assumptions, there is not a business case. However, taking into account a broader range of business considerations may advance the business case.

A direct benefit-cost analysis was also conducted in conjunction with the discounted cash flow analysis. The net present value from the direct benefit-cost perspective was calculated to be a negative $20.5 million, providing a benefit to cost ratio of 0.42.

Despite the lack of a business case for this specific situation, the procedure here outlines an economic evaluation method a regulator may use to evaluate rate base approval of an EES system. As mentioned previously, a utility would have all of the necessary data to conduct a more robust estimation of the benefits and costs of such a system and thus this procedure would lead to a discounted cash flow analysis that a regulator could use to determine rate base approval. Importantly, the regulator (and its utility) would also need to include a cost-effectiveness comparison to different alternatives, including no system modification, but following this methodology, this should be a relatively straightforward process.

3.2 Case Study 2: Distributed Generation Smoothing and Integration

Distributed generation resources have the potential to play a major role in the nation's future electricity grid. A utility may consider utilizing distributed generation resources on its electricity network to more efficiently serve its load. This could be especially true in instances where load is geographically distributed. It could also be true where one portion of the load is sufficiently distant from the rest of the transmission network that delivering power to that load pocket reliably may require significant transmission and distribution investment.

It is possible, in the near future, that a utility will submit a rate case requesting recovery for distribution level EES storage investments on its power grid. It could use this system to improve grid performance and reliability, avoid upgrade costs, while addressing the reliability or shortcomings of a distributed energy resource. Additionally, a utility may consider energy storage systems as a necessary means of effective operation of a customer owned distributed generation where the customer is attempting to sell electricity back onto the distribution network. As in the previous section, this section outlines a process to evaluate the cost-effectiveness of such a system using a DCF analysis.

3.2.1 Functional Uses

In this application, a storage device will be located at the generation site of a small, distributed generation resource, in this case, a 1MW solar array. The local peak load at the distributed resource site is 1 MW. Depending on the time of year, and thus the solar resource available, the EES system will be used to provide a number of benefits. As alluded to above, the EES system will be charged using either or both electricity from the distributed resource and the electric grid. It will be discharged to support the distributed generation resource as needed.

As before, it is assumed that the distributed generation resource and the associated energy storage system will be owned and operated by a regulated utility within the territory of a regional transmission organization or independent system operator (RTO/ISO).[60] Thus, the regulated utility will need to submit a rate base case to its state Public Utility Commission to recover system costs.

The reasons for a utility to consider such a system could be: 1) because of the transmission and distribution system and the location of the load relative to the system, it may be more cost-effective to utilize distributed generation and an EES system; 2) Load may expand in a localized region; for example, a new subdivision built where the current transmission to that area might be insufficient to meet that extra load. DG and an EES would be an alternative option. 3) Utility owned DG may already exist and its operation not optimal. An EES might allow for more efficient and lower cost operation by utilizing less grid electricity. 4) The state may mandate that the utility obtain a portion of its energy from renewable energy sources under an RPS. 5) Outage mitigation for unreliable systems.

[60] This assumption will allow for the use of market rates to estimate benefits. However, a utility may not both add an asset to its rate base and participate in a market using that same asset.

Monetary benefits and avoided costs include:

1. Intermittent Distributed Generation: The EES system would support the PV DG installation by avoiding energy backflow to the grid, providing necessary ancillary services, and eliminating or reducing any other required upgrades, such as additional capacity, to efficiently operate the DG installation

2. In-Basin Generation: Within the localized area of the DG resource, an EES system can provide additional capacity to solve capacity issues. This is dependent upon the situation.

3. Intermittent resource output smoothing: An EES system could smooth the output of the renewable DG installation by charging when output spikes and discharging when output drops.

4. Power Reliability: An EES system could also provide energy downstream in case of system outages assuming there is still reliance on the electric grid downstream of the EES system. The value would be quantified as the value to the utility of avoided customer outages (value of lost load).[61]

3.2.2 Required Technology Characteristics

There are a number of different EES technologies, all of which have different technical performance, operational, and cost characteristics that need to be considered. In order to choose the optimal technology that will perform best under the above conditions and best serve the required application, necessary technology characteristics need to be explicitly defined:

1) Medium-to-low energy capacity: The system is a small 1 MW PV system; long-term output fluctuation should be limited.
2) Low power output: A small 1 MW PV system would require a relatively similarly sized EES system.
3) Moderate to frequent charge/discharge frequency: This could vary depending on the situation and the weather conditions, but likely up to several charge-discharge cycles may be required over a day.
4) Limited depth of discharge capability: considering the application is primarily for PV firming and preventing backflow, a large depth of discharge capability is not necessary. There may be, however, instances, specifically outages, where significant discharge may be required.
5) There may be some limitations on site implementation: Being located near commercial or residential localities necessitates safety be a critical concern. Additionally, the system should present limited disruption both during installation and during operation. Sizing concerns are also an issue: the system and its ancillary components cannot have a large spatial footprint. Most of the infrastructure to support installation and operation must also be present.

Considering that this distributed PV system is sized at 1 MW, for this case, a 500 kW EES system is assumed able to deliver the necessary power to meet this application. This rating can vary significantly depending on the weather profile of the local area and thus the daily output profile for the PV system. It would also depend on the specific situation of the distributed generation system, that is, its distance from

[61] Care should be taken to ensure that this reliability benefit is not double counted with the DG integration benefit.

the proposed EES system, and the characteristics of the local distribution network.[62] It will also be assumed that for this particular situation, 1 hour of total capacity, or discharge, will be necessary to serve the application. Thus, this system will need to provide 500kWh of energy storage capacity.

These requirements are within the range of what a battery EES system could provide. The power requirement is too low and the application too small to consider pumped hydro or compressed air energy storage. Additionally the energy capacity requirement (alternatively discharge timeframe) and small system size prevent a flywheel EES system from being considered. Therefore, a battery system would likely be the best choice.[63]

In this case, a 500kW/500kWh Advanced Lead-Acid storage system has been selected as the best option. The frequent charge/discharge cycling, limited depth of discharge potential, the low O&M requirement, and sizing and safety requirements lead to advanced lead acid as the best choice. Other options that could be considered include lithium-ion systems, excluded here due to the potential for safety issues in the case of improper operation. Sodium Sulfur (NaS) and various flow batteries have not been chosen as sizing and O&M concerns come into play. Ideally, as in the previous case, a utility would conduct a performance-cost analysis to determine the optimum choice.[64]

3.2.3 Discounted Cash Flow Analysis Assumptions

In order to conduct the DCF benefit-cost analysis, the following assumptions were used for benefits and costs:

3.2.3.1 Monetary Benefits and Avoided Costs Assumptions

- Monetary benefits are based on the deferred cost of distribution upgrades. This will be very situation specific and should relatively be easily estimated by the utility. Here, they are assumed as $300/kW.
- Regulation service procurement costs are based on CAISO average prices for 2007-2010 for regulation up and regulation down service.
- Benefit values will be escalated 2% annually.

3.2.3.2 Costs Assumptions

- 15 year life for the Advanced Lead Acid System
- $3,000 annual O&M
- O&M cost escalation at 2% annually
- 30% ITC (Federal Investment Tax Credit)
- 0% salvage value
- Total system cost of ***$810***/ kW:15% installation (site preparation)) and 85% battery capital (complete system)

[62] In a complete evaluation, an EES system would need to be sized considering wind output data and would likely involve modeling economic considerations.

[63] There may be other options not discussed here.

[64] Additional detail about advanced lead acid batteries is provided in the appendix and in the additional sources listed in the appendix.

3.2.4 Discounted Cash Flow Analysis Calculations

3.2.4.1 Monetary Benefits and Avoided Costs

The benefits chosen here were: 1) intermittent distributed generation support, 2) distribution power reliability, 3) in-basin generation, and 4) intermittent resource smoothing. The specific assumptions used to make the benefit value calculation are provided in Table 7 and Table 8 below.

Table 7: Value estimates used in calculations for case study 2

Value Assumptions	
Capacity (DG) Cost [$/kW-yr.]	$71.82
Wind Integration Adder [$/MWh]	$4
Distribution Upgrade Cost [$/kW]	$300

Table 8: EES and RE system performance characteristics for case study 2

System Assumptions	
Battery Capacity [kW]	500
Batter System Efficiency [%]	90%
Solar Farm Maximum Capacity [MW]	1
Wind Farm Firm Capacity (w/Battery) [kW]	500
System Lifetime [years]	15

Table 9 specifies assumptions about each individual benefit and the calculation to determine the value of that benefit, in order to determine a total value of the EES system on an annual and one-time basis.

Table 9: Benefit value specifications for annual and one-time bases for case study 2

Benefit Value Calculation		
1	**Intermittent Distributed Generation Support (one time)**	**$150,000**
	avoided system upgrade costs	
	Value = Distribution Upgrade Cost X Battery System Capacity	
2	**Distribution Power Reliability (one time)**	**$150,000**
	avoided cost of new infrastructure	
	Value = Distribution Upgrade Cost X Battery System Capacity	
3	**In-Basin Generation (per year)**	**$35,910**
	avoided cost of additional DG to meet the capacity requirement	
	Value = Capacity (DG) Cost X Battery System Capacity	
4	**Intermittent Resource Smoothing (per year)**	**$17,520**
	avoided integration cost of an intermittent resource	
	Value = Wind Integration Adder X Solar Farm Firm Capacity X 8760 hrs.	

Yearly Benefit Value		
One-Time Benefits		
1	**Intermittent Distributed Generation Support (one time)**	$150,000
2	**Distribution Power Quality (one time)**	$150,000
	Total	**$300,000**
Yearly Benefits		
3	**In-Basin Generation (per year)**	$35,910
4	**Intermittent Resource Smoothing (per year)**	$17,520
	Total	**$53,430**

3.2.4.2 Costs

Determining lifetime system costs is a relatively straightforward exercise. The same process that is used for other capital improvements can also be applied to EES systems as long as the appropriate assumptions are taken into account. A simplified evaluation breakdown is presented below.

3.2.4.1 Investment Criterion: Net Present Value

Benefits are added together as presented above. The initial and yearly costs are identified and any applicable investment tax credit (ITC), or other incentive, is applied. Lifetime is also specified and double declining balance depreciation is applied. Table 10 below presents the fundamental performance and economic assumptions used in the NPV calculation shown in Table 6 as a simple 15-year net present value calculation for this system.

Table 10: Performance and economic assumptions used in NPV calculations for case study 2

System Size [MW]	500
System Cost [$/kW]	$810
Equipment Capital	$344,250
Installation Capital	$60,750
Investment Tax Credit	30%
Total Capital Investment	$283,500
Salvage Value	-
Clean-up Costs	-
Yearly O&M	$3,000
Lifetime (n)	15
Discount rate (i) [65]	7.4%
Yearly Benefit	$53,430
One-Time Benefit	$300,000
Benefit & Cost Escalation Factor	2%
Marginal Tax Rate	35%

[65] 7.4% is the cost of capital as utilized by the *Energy Information Administration* in its Annual Energy Outlook for 2012.

Table 11: EES revenues, costs, and NPV by year for case study 2

Year	Capital Cost	Operating Costs	Gross Revenue	Net Revenue[66]	Present Value of Net Revenue	Total Present Value
0	($283,500.00)					(283,500)
1		($3,000)	353,430	241,010	224,404	224,404
2		($3,060)	54,499	44,901	38,927	38,927
3		($3,121)	55,589	44,041	35,550	35,550
4		($3,184)	56,700	43,398	32,618	32,618
5		($3,247)	57,834	42,946	30,054	30,054
6		($3,312)	58,991	42,806	27,892	27,892
7		($3,378)	60,171	43,530	26,409	26,409
8		($3,446)	61,374	44,268	25,007	25,007
9		($3,515)	62,602	45,021	23,680	23,680
10		($3,585)	63,854	45,790	22,425	22,425
11		($3,657)	65,131	46,573	21,237	21,237
12		($3,730)	66,433	47,372	20,113	20,113
13		($3,805)	67,762	48,187	19,049	19,049
14		($3,881)	69,117	49,019	18,043	18,043
15		($3,958)	70,500	49,867	17,090	17,090
Total						**$298,997**

[66] Net revenue includes operating costs, gross revenue, taxes, and depreciation.

3.2.5 Discounted Cash Flow Analysis Results and Summary

The total net present value for this system amounts to a positive $299,000. Based on this analysis, the project is cost-effective and provides a 5.5% ROI. Some of these assumptions may present an optimistic perspective on the project. However, they do indicate that a business case can be made for an EES system serving such an application.

A direct benefit-cost analysis was also conducted in conjunction with the discounted cash flow analysis. The net present value from the direct benefit-cost perspective was calculated to be a positive $498,500 providing a benefit to cost ratio of 2.6 and a 76% ROI.

The procedure here outlines a method a regulator may use to evaluate rate base approval of an EES system serving such an application. The application in this case is different from the one discussed previously, but the methodology for evaluating its cost-effectiveness is similar. A utility would have all of the necessary data to conduct a more robust estimation of the benefits and costs of such a system and thus this procedure would lead to a DCF benefit-cost analysis that that a regulator could use to determine rate base approval. The regulator would also need to include a cost-effectiveness comparison to different alternatives, but such, again following this methodology, should be a relatively straightforward exercise.

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