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DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA

Abbas A. Akhil, Georgianne Huff, Aileen B. Currier, Benjamin C. Kaun, Dan M. Rastler, Stella Bingqing Chen, Andrew L. Cotter, Dale T. Bradshaw, and William D. Gauntlett

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Abstract

The Electricity Storage Handbook (Handbook) is a how-to guide for utility and rural cooperative engineers, planners, and decision makers to plan and implement energy storage projects. The Handbook also serves as an information resource for investors and venture capitalists, providing the latest developments in technologies and tools to guide their evaluations of energy storage opportunities. It includes a comprehensive database of the cost of current storage systems in a wide variety of electric utility and customer services, along with interconnection schematics. A list of significant past and present energy storage projects is provided for a practical perspective. This Handbook, jointly sponsored by the U.S. Department of Energy and the Electric Power Research Institute in collaboration with the National Rural Electric Cooperative Association, is published in electronic form at www.sandia.gov/ess.

This Handbook is best viewed online.

Comments, inquiries, corrections, and suggestions can be submitted via the website www.sandia.gov/ess/, beginning August 1, 2013.

REVISION LOG

Rev. Number	Date	Purpose of Revision	Document Number	Name or Org.
Rev. 0	July 2013	Update and revise the 2003 EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications to provide how-to information for various stakeholders.	SAND2013-5131	DOE (SNL), EPRI, NRECA
Rev. 1	Jan. 2015	Chapter 2: • Added information highlighting thermal storage solution. Chapter 3: • Added subchapter highlighting tools available to use to evaluate a Storage solution from a modeling and simulation standpoint. • Added new Subsections 3.3.1 through 3.3.6. Chapter 4: • With respect to the "AC battery" system: o Added a reference to the patent #4,894,764. o Added a picture of an AC battery. • Added information about KIUC and the RFI and RFP. Appendix A: • Added information regarding ES models and tools. Appendix B: • Expanded on three energy and power cost components. o Calculation of the sum of the energy and power components. o How these costs are highly system dependent and do not scale linearly. • Expanded on derivation of the Total Plant Cost (TPC) and referenced costs that are components of the TPC. • Added explanation of equipment costs. Appendix F: • Added introductory text. Appendix G: • Added reference to AC battery patent. • Removed Hawaii battery projects information.	SAND2015-1002	DOE (SNL), EPRI, NRECA

ACKNOWLEDGMENTS

Without the work of the Energy Storage Handbook (Handbook) Advisory Panel and contributors, this Handbook could neither have been completed nor would it have the credibility or value to the energy storage community that the authors intend.

The authors are very grateful to the Advisory Panel, who diligently reviewed this Handbook for technical accuracy and content and contributed their unique perspectives. The Panel members include: Eva Gardow, FirstEnergy; Steve Willard, Public Service Company of New Mexico; Naum Pinsky, Southern California Edison; Rick Winter, UniEnergy Technologies; Mike Jacobs, Xtreme Power; Kimberly Pargoff, A123; Pramod Kulkarni, Customized Energy Solutions; Chet Sandberg, Electricity Storage Association; Janice Lin, California Energy Storage Association; and Ali Nourai, DNV-KEMA. Their guidance has been invaluable in ensuring that the Handbook can meet the needs of a broad audience.

The authors would also like to thank Ray Byrne, Verne Loose, Dhruv Bhatnagar, Ben Schenkman, Jason Neely, and Anthony Menicucci, Sandia National Laboratories, for their many hours of writing and numerous reviews to prepare the content for the Handbook.

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Special thanks are due to Leona Van Ostrand of Raytheon Company and Sharon O’Connor, Eleni Otto, and Diane L. Miller of Sandia National Laboratories for their tireless editing, re-editing, and proofreading of countless drafts and for producing what the authors hope is a cohesive document.

Finally, the authors wish to express their appreciation to the U.S. Department of Energy’s Office of Electricity and Dr. Imre Gyuk, Energy Storage Program Manager; Haresh Kamath, Electric Power Research Institute; and Robbin K. Christianson, National Rural Electric Cooperative Association, for their vision and collaboration through all phases in the development and compilation of the Handbook.

FOREWORD

From: Dr. Imre Gyuk

I am most proud to introduce the 2013 edition of the DOE/EPRI Electricity Storage Handbook prepared in collaboration with the National Rural Electric Cooperative Association.

When we put together the first EPRI/DOE Energy Storage Handbook some 10 years ago, the field was very much in its infancy. There were only a few demonstrations and almost no commercially viable deployment. The Handbook consisted mostly of a survey of available storage technologies and analysis of potential applications. Things are vastly different now. There are dozens of demonstrations of manifold technologies in a wide spectrum of applications. Sizes vary from tens of kW to 20-30MW. Storage for frequency regulation has become fully commercial and facilities are being built to explore renewable integration, PV smoothing, peak shifting, load following and the use of storage for emergency preparedness. Important policy decisions are being made in the regulatory arena to pave the way for an equitable deployment of storage. This is happening not only in the U.S. but round the globe: Among others, Germany, Japan, and China are all becoming strong advocates of energy storage.

Now, in 2013, it is time to publish a new Handbook. It will fill an industry-wide need for a single-point resource to describe the services and applications of energy storage in the grid, the current storage technologies and their commercial status, system costs, and performance metrics. DOE has taken the lead to fill this industry need by partnering with the Electric Power Research Institute (EPRI) to produce this Handbook.

I want to recognize the tremendous cooperation and sharing of data by EPRI to make this happen. This effort brought together the resources of two leading authorities in the Energy Storage field to produce a landmark work that will greatly benefit the storage industry. Collaboration with NRECA additionally ensures that the Handbook is available to the widest possible audience of storage users including the investor-owned utilities who are members of EPRI and the large community of rural cooperatives across the Nation who are members of NRECA.

Lastly, this is a free, publicly available resource downloadable through the internet by any interested reader. We hope that it will lead to more technology, more deployment, and a structured regulatory environment, putting energy storage well on the road to full commercialization.

Dr. Imre Gyuk
US DOE/OE Energy Storage Program

From: Haresh Kamath

I am very pleased to join my friend and colleague Dr. Imre Gyuk in introducing the 2013 edition of the DOE/EPRI Electricity Storage Handbook, prepared in collaboration with the National Rural Electric Cooperative Association.

The first edition of the Handbook, a collaborative effort between EPRI and DOE, was released in 2003, just in time to address the growing need for data and insight on energy storage technologies in transmission and distribution applications. The opportunities for improving asset utilization of transmission and distribution through the strategic use of storage, as well as the various dynamic operating benefits of storage, were already well-recognized. The Handbook was an early attempt to quantify the benefits from storage systems used in multiple applications. In 2004, the Handbook was further enhanced through the publication of a supplement that addressed the use of storage in increasing grid flexibility in a world with rapidly increasing penetrations of variable renewable energy sources.

Since then, the field of energy storage has moved forward at an incredible pace, on both the application and technology fronts. This progress has come about through the tireless work of a remarkable community of scientists, engineers, economists, and businesspeople from across the world, representing diverse organizations including utilities, generation companies, universities, national laboratories, consulting organizations, technology developers, and government agencies.

The accomplishments of the last decade are due in no small part to the leadership and vision of DOE and its partners, particularly at Sandia National Laboratory, as well as to organizations such as NRECA. EPRI has been proud to collaborate with these visionary partners in exploring the performance and applications of energy storage technologies for the grid.

While much work is yet required before storage technologies become commonplace, it is important to recognize the distance we have come towards achieving this goal, and the experience and knowledge gained in the journey. This Handbook serves as a distillation of this knowledge, which will hopefully facilitate the broader use of utility energy storage in maintaining the reliability and affordability of the modern grid in an environmentally responsible way.

We at EPRI would like to thank DOE and NRECA for their interest and commitment in producing this publicly-available resource for those pursuing the use of energy storage in grid applications.

Haresh Kamath
EPRI Program Manager for Energy Storage

CONTENTS

FIGURES

TABLES

GLOSSARY

– A –	
AC	alternating current
ACE	area control error
AEP	American Electric Power
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
ARRA	American Recovery and Reinvestment Act of 2009
AS	ancillary service
– B –	
BPA	Bonneville Power Authority
– C –	
CAES	compressed air energy storage
CAISO	California Independent System Operator
Calculator	Lifecycle Analysis Calculator (EPRI)
CCGT	Combined-cycle gas turbine
CES	Community Energy Storage
CESA	California Energy Storage Alliance
CO2	carbon dioxide
CONE	cost of new entry
Co-op(s)	Rural electric cooperative(s)
CPUC	California Public Utility Commission
CT	combustion turbine
– D –	
DAS	Data Acquisition System
dc	direct current
DESS	Distributed Energy Storage System
DETL	Distributed Energy Technologies Laboratory
DOD	depth of discharge
DOE	U.S. Department of Energy
$/kW-month	dollars per kilowatt per month
DR	demand response
DSA	Dynamic Security Assessment
DSCR	Debt Service Coverage Ratio
– E –	
EES	Electric Energy Storage
EESAT	Electrical Energy Storage Applications and Technologies
EMC	electromagnetic compatibility
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESA	Electricity Storage Association

ESAL	Energy Storage Analysis Laboratory
ESCO	energy service company
ESCT	Energy Storage Computational Tool
ESIF	Energy Systems Integration Facility
ESPTL	Energy Storage Performance Test Laboratory
ESS	Energy Storage Systems or Electricity Storage Systems
ESTF	Energy Storage Test Facility
ESTP	Energy Storage Test Pad
ESVT	Energy Storage Valuation Tool
ETT	Electric Transmission Texas
EV	Electric Vehicle
– F –	
Fe-Cr	Iron-chromium
FERC	Federal Energy Regulatory Commission
– G –	
G & T	generation and transmission
GE	General Electric
GHG	greenhouse gas
GST	Grid Storage Technologies
GW	gigawatts
– H–	
H-APU	Hybrid Ancillary Power Unit
Handbook	Electricity Storage Handbook
HCEI	Hawaii Clean Energy Initiative
hr	hour
Hz	hertz
– I –	
IDC	Interest During Construction
ILZRO	International Lead Zinc Research Organization
IPP	Independent Power Producer
IR	infrared
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
IOU	Investor Owned Utility
– J –	
JCP&L	Jersey Central Power and Light Company
– K –	
KIUC	Kauai Island Utility Cooperative
kW	kilowatt
kWh	kilowatt hour

– L –	
LA	lead-acid
LCOE	levelized cost of energy
Li	lithium
LMP	locational marginal pricing
LSEs	load-serving entities
– M –	
MMBtu	one million Btu
Muni	municipal electric utility
MVAR	mega volt-ampere reactive
MW	megawatt
MWh	megawatt hour
– N –	
Na	sodium
Na_2S5	sodium pentasulfide
NaCl	salt
$NaAlCl_4$	sodium ion conductive salt
NaS	sodium sulfur
NAS™	registered trademark for NGK Insulators, Ltd. sodium sulfur batter
NEC	National Electrical Code
NEDO	New Energy Development Organization
NERC	North American Electric Reliability Council
NESC	National Electric Safety Code
NETL	National Energy Technology Laboratory
Ni	nickel
$NiCl_2$	nickel chloride
NIST	National Institute of Standards and Technology
NISTIR	National Institute of Standards and Technology Interagency Report
NiMH	nickel metal-hydride
NOx	nitrogen oxides
NPV	Net Present Value
NRECA	National Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYSERDA	New York State Energy and Development Authority
– O –	
O & M	Operations and Maintenance
OE (DOE)	Office of Electricity Delivery and Energy Reliability
OEM	original equipment manufacturer
OIR	
– P –	
PbO2	lead dioxide

PCS	power conversion system or power conditioning system
PCT	Patent Cooperation Treaty
PG&E	Pacific Gas and Electric
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
PHES	pumped hydroelectric energy storage
PJM	PJM Interconnection, LLC
PNM	Public Service Company of New Mexico
PNNL	Pacific Northwest National Laboratory
PQ	power quality
PREPA	Puerto Rico Electric Power Authority
PSLF	Positive Sequence Load Flow
PUC	Public Utility Commission
PV	photovoltaic
Pb-acid	Lead Acid Battery
– Q –	
No “Q” terms	
– R –	
R&D	research and development
Redox	reduction and oxidation
RFI	Request for Information
RFP	Request for Proposals
RFQ	Request for Quote
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
– S –	
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SCR	Selective Catalytic Reduction
SDG&E	San Diego Gas and Electric
SGIP	Self-generating Incentive Program
SMD	Standard Market Design
SNL	Sandia National Laboratories
– T –	
T&D	transmission and distribution
TCOS	transmission cost of service
TEPCO	Tokyo Electric Power Company
TESA	Texas Energy Storage Alliance
TIEC	Texas Industrial Energy Consumers
TOU	time of use
TPC	total plant cost
TSP	Tehachapi Wind Energy Storage
TVA	Tennessee Valley Authority

– U –	
UBG	Utility Battery Groups
UPS	uninterruptible power supply
– V–	
V	volts
VAR	reactive power and volt-ampere reactive
VLA	vented lead-acid
VPS	VRB Power Systems
VRLA	valve regulated lead-acid
W –	
WACC	weighted average cost of capital
WECC	Western Electric Coordinating Council
– X –	
No “X” terms	
– Y –	
No “Y” terms	
– Z –	
$ZnBr_2$	zinc bromine

INTRODUCTION

Publication of the Electricity Storage Handbook (Handbook) is funded through Dr. Imre Gyuk, U.S. Department of Energy (DOE) and Haresh Kamath, Electric Power Research Institute (EPRI) in collaboration with the National Rural Electric Cooperative Association (NRECA). Development of the Handbook's content was guided by a ten-member Advisory Panel representing system vendors, electric utilities, regulators, and trade associations.[1]

The Handbook includes discussion of stationary energy storage systems that use batteries, flywheels, compressed air energy storage (CAES), and pumped hydropower and excludes thermal, hydrogen, and other forms of energy storage that could also support the grid, such as plug-in electric vehicles (PEVs) or electric vehicles (EVs). Both DOE and EPRI have separate programs which support PEVs and EVs.

This edition of the Handbook builds primarily upon the EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications, released in December 2003, a landmark collaboration between EPRI and DOE. The first Handbook presented a broad perspective on the potential of energy storage in the national grid, comparative storage technology and benefits assessments, and a review of ten different storage technologies in 14 transmission and distribution (T&D) categories.

This edition of the Handbook is a how-to guide for electric systems engineers/planners, energy storage system vendors, and investors to aid in the selection, procurement, installation, and/or operation of stationary energy storage systems in today's electric grid. Various perspectives of grid electricity storage are presented for different stakeholders: generators and system operators, load-serving entities (LSEs) with various ownership structures, and customers. The Handbook includes a review of the current status of technical, financial, regulatory, and ownership issues that impact energy storage adoption, primarily with a U.S.-centric focus. Much of the material presented in this edition of the Handbook has been condensed and updated from existing reports from Sandia National Laboratories (SNL), EPRI, NRECA, other national laboratories, and industry sources published from the mid-1980s to the present. This edition presents updated information on storage technologies and their benefits in an operational and regulatory environment and recognizes energy storage as a grid component in further detail than the 2003 Handbook.

[1] The advisory panel members are Eva Gardow, FirstEnergy; Steve Willard, Public Service Company of New Mexico; Naum Pinsky, Southern California Edison; Rick Winter, UniEnergy Technologies; Mike Jacobs, Xtreme Power; Kimberly Pargoff, A123; Pramod Kulkarni, Customized Energy Solutions; Chet Sandberg (representing Electricity Storage Association); Janice Lin, California Energy Storage Association; and Ali Nourai, DNV-KEMA.

OUTLINE

This Handbook is organized into four chapters and appendices. Roadmaps are provided at the end of this section to aid in navigation of the Handbook.

Chapter 1: Electricity Storage Services and Benefits

The first chapter reviews 14 services and functional uses, including electricity storage services to the grid, ancillary services, grid system services and functional uses, end user/utility customer functional services and renewables integration that electricity storage provides to the grid as a generation, transmission and distribution (T&D), and customer-side resource. The chapter also provides a brief review of simultaneous use of electricity storage for multiple applications (stacked).

Chapter 2: Electricity Storage Technologies: Cost, Performance, Maturity

The second chapter presents the principles of operation for pumped hydro and Compressed Air Energy Storage (CAES) and the electrochemistry for a family of currently available battery technologies. Each technology section also includes capital and levelized cost of energy (LCOE) charts based on the responses of a first-of-a-kind, comprehensive survey of more than 40 storage vendors. An appendix to this chapter provides further detail on the component and system cost for each technology to provide select grid services, including representative schematics for each service.

Chapter 3: Methods/Tools for Evaluating Electricity Storage

The third chapter discusses screening-level and advanced production cost, electric stability, and financial tools that can be used to evaluate the impact of electricity storage in the grid. An appendix to this chapter provides a summary of specific evaluation tools currently available.

Chapter 4: Storage Systems Procurement and Installation

The final chapter provides an overview of procurement options based on approaches used both in the past and for current projects. Sections in this chapter address purchasing options, safety, interconnection and communication, warranty, and disposal issues. Further details on noteworthy past and present storage projects and a worldwide storage project database initiated by the DOE are presented in a related appendix.

References and Appendices

A glossary of select terms and an extensive reference database of reports published by DOE, EPRI, NRECA, and industry sources are among the supporting appendices provided at the end of the Handbook. References for material in the text are provided in footnotes.

Handbook Roadmaps

This Handbook addresses the what, why, and how of electricity energy storage for grid and stand-alone applications. It is intended for use by an audience that falls broadly into three groups: utility and co-operative (co-op) engineers/system planners; system vendors and investors; and regulators and policy makers. The authors have developed roadmaps that guide the reader to the relevant sections of the Handbook based on their perceived needs in their exploration of electricity storage. These audiences each have different questions of significance to them, and each roadmap is organized to suit their needs. The following roadmaps provide a suggested navigation of the four chapters and their corresponding appendices providing additional detail and references on each topic of interest.

Suggested Guide for Utility and Co-op Engineers/System Planners

What are the relevant use cases for electricity storage?

Chapter 1 identifies storage services and functional uses including storage for renewable integration and provides ranges and minimum requirements for storage systems with illustrative examples. The use cases and applications span generation, transmission and distribution (T&D) as well as customer-side applications.

What are the technology options and how can use cases of interest be assessed?

Chapter 2 describes current storage technologies and their high-level performance characteristics, maturity, and costs in dollars per kilowatt ($/kW) and dollars per kilowatt hour ($/kWh).

Chapter 4 identifies various technology-assessment tools from preliminary screening to more detailed analysis. Selected tools are described in Appendix A.

What are the costs and important procurement and installation issues?

Chapter 4 presents two different system procurement/ownership options for investor-owned utilities (IOUs) and co-ops. It addresses practical safety, interconnection, warranty, and codes issues to guide successful project completion.

Appendix B gives detailed system and component cost information organized by storage technology. These data were obtained from system vendors for the various technologies currently in use for stationary applications and were used to derive the capital costs in Chapter 2.

Appendix C provides sample Requests for Information (RFIs) and Requests for Proposals (RFPs) that can be modified to suit specific needs and serve as guidelines for system procurement processes.

Appendix D illustrates interconnection configurations for selected storage systems and gives representative interconnection equipment costs. These configurations can be changed to meet more specific site needs as necessary.

Appendix C contains a sample specification for cyber security guidance specific to Li-ion battery systems that can serve as a guideline for other storage technology systems.

How have public utility commissions (PUCs) treated storage and what are the regulatory drivers for storage?

Appendix E provides a comprehensive review PUC cases where storage was included and their outcomes.

Chapter 4 summarizes enacted and pending Federal Energy Regulatory Commission (FERC) and State regulatory initiatives that promote storage.

Which trade associations are promoting storage and what are the venues for networking in this community?

Chapter 4 identifies those industry groups and not-for-profit conferences that provide networking opportunities with system vendors, technology developers, and other utilities that use or are considering storage, as well as a window into Federal and State programs that promote storage deployment.

Suggested Guide for System Vendors and Investors

How do utilities and co-ops purchase electricity storage systems?

Chapter 4 presents two different ownership options for electricity storage systems and provides a high-level discussion of safety, interconnection, warranty, and codes that are important from the customer perspective.

Appendix C shows sample RFI and RFP documents that are representative of the terms and conditions that utilities and co-ops will likely seek in the procurement process.

Which industry trade groups promote electricity storage?

Chapter 4 identifies those industry groups that actively promote electricity storage and not-for-profit conferences that provide networking opportunities with a wide spectrum of the storage community.

What are the policy and regulatory drivers that impact electricity storage?

Appendix E provides a comprehensive review of past PUC cases that included electricity storage and their outcomes.

Chapter 4 lists enacted and pending FERC and State regulatory initiatives that promote electricity storage.

What are the relevant codes, interconnection, and safety issues?

Chapter 4 discusses safety, interconnection, communication, and warranty issues that are important to prospective customers in the utility sector.

Where can full systems be tested and what are the test standards/protocols?

Appendix F identifies several test facilities and capabilities which can test fully configured systems and discusses the test protocols and standards that are being formulated to govern standardized performance testing of storage systems.

Suggested Guide for Regulators and Policy Makers

What are the services and functional uses of electricity storage?

Chapter 1 describes various services and functional uses of electricity storage in the grid with illustrative charts, including the use of electricity storage to support renewable resource integration.

What are the current electricity storage technologies?

Chapter 2 describes current electricity storage technologies, their high-level performance characteristics, and their maturities. Additional cost detail is provided in Appendix B and Appendix D.

How has storage been addressed by other PUCs?

Appendix E presents a summary of regulatory cases and the outcomes in several State PUC filings that address electricity storage.

ENERGY STORAGE 101

What is energy storage? Energy storage mediates between variable sources and variable loads. Without storage, energy generation must equal energy consumption. Energy storage works by moving energy through time. Energy generated at one time can be used at another time through storage. Electricity storage is one form of energy storage. Other forms of energy storage include oil in the Strategic Petroleum Reserve and in storage tanks, natural gas in underground storage reservoirs and pipelines, thermal energy in ice, and thermal mass/adobe.

Electricity storage is not new. In the 1780s, Galvani demonstrated “animal electricity” and in 1799 Volta invented the modern battery. In 1836, batteries were adopted in telegraph networks. In the 1880s, lead-acid batteries were the original solution for night-time load in the private New York City area direct current (dc) systems. The batteries were used to supply electricity to the load during high demand periods and to absorb excess electricity from generators during low demand periods for sale later. The first U.S. large-scale electricity storage system was 31 megawatts (MW) of pumped storage in 1929 at the Connecticut Light & Power Rocky River Plant. As of 2011, 2.2%[2] of electricity was stored world-wide, mostly in pumped storage.

In this Handbook, a complete electricity storage system (that can connect to the electric grid or operate in a stand-alone mode) comprises two major subcomponents: storage and the power conversion electronics. These subsystems are supplemented by other balance-of-plant components that include monitoring and control systems that are essential to maintain the health and safety of the entire system. These balance-of-plant components include the building or other physical enclosure, miscellaneous switchgear, and hardware to connect to the grid or the customer load. A schematic representation of a complete energy storage system is shown in Figure 1 with a generic storage device representing a dc storage source, such as a battery or flywheel.

In battery and flywheel storage systems, the power conversion system is a bidirectional device that allows the dc to flow to the load after it is converted to alternating current (ac) and allows ac to flow in the reverse direction after conversion to dc to charge the battery or flywheel. The monitoring and control subcomponents may not be a discrete box, as shown in Figure 1, but could be integrated within the power conversion system (PCS) itself.

[2] Source: *Annual Electric Generator Report,* 2011 EIA - Total Capacity 2009; U.S. Energy Information Administration, Form EIA-860, 2011.

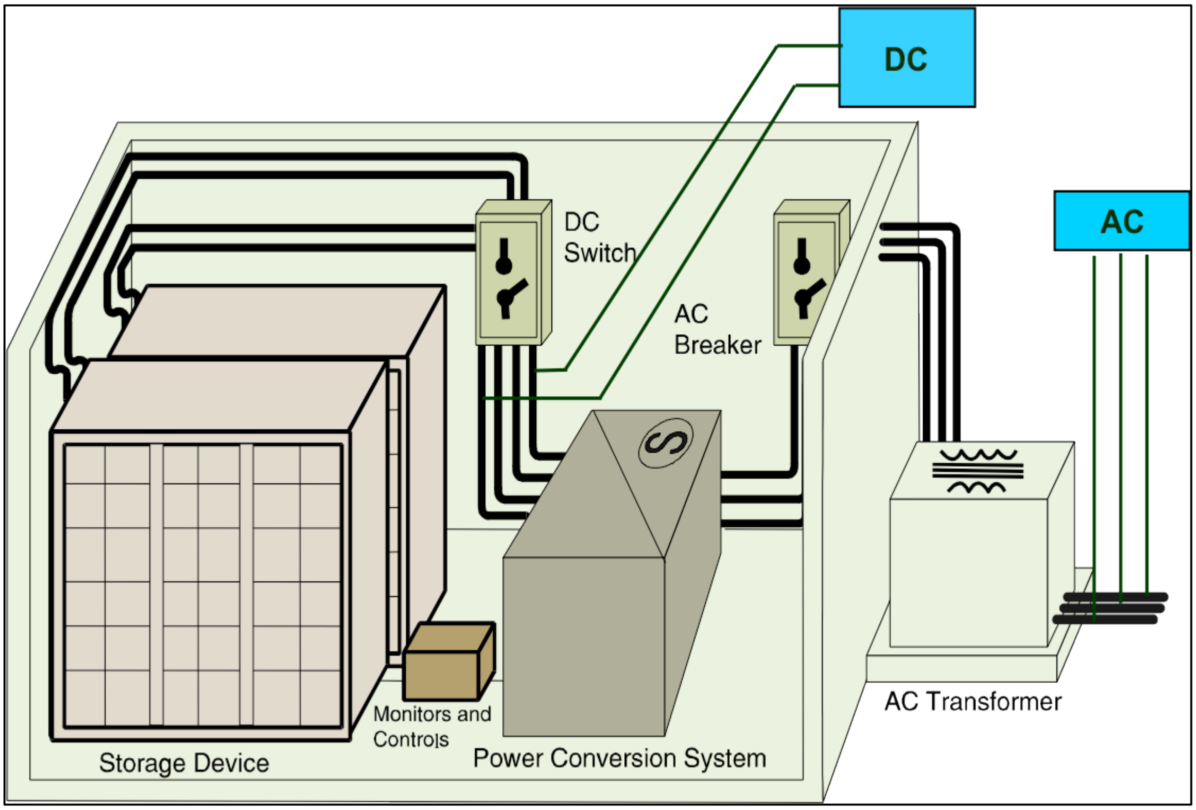

Figure 1. Schematic of a Battery Energy Storage System
(Source: Sandia National Laboratories)

CAES involves high-pressure air stored in underground caverns or above-ground storage vessels (e.g., high-pressure pipes or tanks). In pumped hydroelectric energy storage (PHES), energy is stored by pumping water to an upper reservoir at a higher elevation than the system's lower reservoir.

CHAPTER 1. ELECTRICITY STORAGE SERVICES AND BENEFITS

Operational changes to the grid, caused by restructuring of the electric utility industry and electricity storage technology advancements, have created an opportunity for storage systems to provide unique services to the evolving grid. Regulatory changes in T&D grid operations, for instance, impact the implementation of electricity storage into the grid as well as other services that storage provides. Although electricity storage systems provide services similar to those of other generation devices, their benefits vary and are thoroughly discussed in this chapter.

Until the mid-1980s, energy storage was used only to time-shift from coal off-peak to replace natural gas on-peak so that the coal units remained at their optimal output as system load varied. These large energy storage facilities stored excess electricity production during periods of low energy demand and price and discharged it during peak load times to reduce the cycling or curtailment of the coal load units. This practice not only allowed the time-shifting of energy but also reduced the need for peaking capacity that would otherwise be provided by combustion turbines. The operational and monetary benefits of this strategy justified the construction of many pumped hydro storage facilities. From the 1920s to the mid-1980s, more than 22 gigawatts (GW) of pumped hydro plants were built in the United States. After this period, the growth in pumped hydro capacity stalled due to environmental opposition[3] and the changing operational needs of the electric grid, triggered by the deregulation and restructuring of the electric utility industry.

By the mid-1980s, the push was stronger to develop battery and other storage technologies to provide services to the electric grid. However, these technologies could not match the ability of pumped hydro to provide large storage capacities. In the late 1980s, researchers at DOE/SNL and at EPRI were identifying other operational needs of the electric grid that could be met in shorter storage durations of 1 to 6 hours rather than the 8 to 10+ hours that pumped hydro provided.

Two SNL reports[4,5] in the early 1990s identified and described 13 services that these emerging storage technologies could provide. A more recent report, Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide[6] expanded the range of the grid services and provided significantly more detail on 17 services as well as guidance on estimating the benefits accrued by these services.[7] Other works have also documented use cases and services

[3] From the 2003 Handbook: ‘‘The addition of pumped hydro facilities is very limited, due to the scarcity of further cost-effective and environmentally acceptable sites in the U.S.’’ *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003.

[4] *Battery Energy Storage: A Preliminary Assessment of National Benefits (The Gateway Benefits Study)*, Abbas Ali Akhil; Hank W Zaininger; Jonathan Hurwitch; Joseph Badin, SAND93- 3900, Albuquerque, NM, December 1993.

[5] *Battery Energy Storage for Utility Applications: Phase I Opportunities Analysis*, Butler, Paul Charles, SAND94-2605, Albuquerque, NM, October 1994.

[6] *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*, Eyer, James M. – distributed Utility Associates, Inc., Garth Corey – Ktech Corporation, SAND2010-0815, Albuquerque, NM and Livermore, CA, February 2010.

[7] An application, or grid service, is a use whereas a benefit connotes a value. A benefit is generally quantified in terms of the monetary or financial value.

that storage provides to the grid. Most notably, EPRI's Smart Grid Resource Center Use Case Repository contains over 130 documents that discuss various aspects of storage.[8] Similarly, California Independent System Operator (CAISO) also describes eight scenarios supplemented by activity diagrams to demonstrate the use of storage for grid operations and control.[9]

This Handbook combines that knowledge base and includes the description and service-specific technical detail of 18 services and applications in five umbrella groups, as listed in Table 1.

Table 1. Electric Grid Energy Storage Services Presented in This Handbook

Bulk Energy Services	
	Electric Energy Time-Shift (Arbitrage)
	Electric Supply Capacity
Ancillary Services	
	Regulation
	Spinning, Non-Spinning and Supplemental Reserves
	Voltage Support
	Black Start
	Other Related Uses
Transmission Infrastructure Services	
	Transmission Upgrade Deferral
	Transmission Congestion Relief
Distribution Infrastructure Services	
	Distribution Upgrade Deferral
	Voltage Support
Customer Energy Management Services	
	Power Quality
	Power Reliability
	Retail Electric Energy Time-Shift
	Demand Charge Management

1.1 Bulk Energy Services

1.1.1 Electric Energy Time-shift (Arbitrage)

Electric energy time-shift involves purchasing inexpensive electric energy, available during periods when prices or system marginal costs are low, to charge the storage system so that the stored energy can be used or sold at a later time when the price or costs are high. Alternatively, storage can provide similar time-shift duty by storing excess energy production, which would otherwise be curtailed, from renewable sources such as wind or photovoltaic (PV). The functional operation of the storage system is similar in both cases, and they are treated interchangeably in this discussion.

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8 EPRI Smartgrid Resource Center: Use Case Repository, http://smartgrid.epri.com/Repository/Search.aspx?search=storage, last accessed May 9, 2013.

9 "*IS-1 ISO Uses Energy Storage for Grid Operations and Control*," Ver 2.1, California ISO, Folsom, CA, November 2010, http://www.caiso.com/285f/285fb7964ea00.pdf, last accessed May 9, 2013.

Technical Considerations

Storage System Size Range: 1 – 500 MW
Target Discharge Duration Range: <1 hour
Minimum Cycles/Year: 250 +

Storage used for time-shifting energy from PV or smaller wind farms would be in the lower end of the system storage size and duration ranges shown above, whereas storage for arbitrage in large utility applications or in conjunction with larger wind farms or groups of wind and/or PV plants would fall in the upper end of these ranges.

Both storage variable operating cost (non-energy-related) and storage efficiency are especially important for this service. Electric energy time-shift involves many possible transactions with economic merit based on the difference between the cost to purchase, store, and discharge energy (discharge cost) and the benefit derived when the energy is discharged.

Any increase in variable operating cost or reduction of efficiency reduces the number of transactions for which the benefit exceeds the cost. That number of transactions is quite sensitive to the discharge cost, so a modest increase may reduce the number of viable transactions considerably. Two performance characteristics that have a significant impact on storage variable operating cost are round-trip efficiency of the storage system and the rate at which storage performance declines as it is used.

In addition, seasonal and diurnal electricity storage can be considered as a bulk service. It can be very useful for wind or PV if there are significant seasonal and diurnal differences.

1.1.2 Electric Supply Capacity

Depending on the circumstances in a given electric supply system, energy storage could be used to defer and/or to reduce the need to buy new central station generation capacity and/or purchasing capacity in the wholesale electricity marketplace.

The marketplace for electric supply capacity is evolving. In some cases, generation capacity cost is included in wholesale energy prices (as an allocated cost per unit of energy). In other cases, market mechanisms may allow for capacity-related payments.

Technical Considerations

Storage System Size Range: 1 – 500 MW
Target Discharge Duration Range: 2 – 6 hours
Minimum Cycles/Year: 5 – 100

The operating profile for storage used as supply capacity (characterized by annual hours of operation, frequency of operation, and duration of operation for each use) is location-specific. Consequently, it is challenging to make generalizations about storage discharge duration for this service. Another key criterion affecting discharge duration for this service is the way that generation capacity is priced. For example, if capacity is priced per hour, then storage plant duration is flexible. If prices require that the capacity resource be available for a specified duration for each occurrence (e.g., five hours), or require operation during an entire time period (e.g., 12:00 p.m. to 5:00 p.m.), then the storage plant discharge duration must accommodate those requirements.

The two plots in Figure 2 illustrate the capacity constraint and how storage acts to compensate the deficit. The upper plot shows the three weekdays when there is need for peaking capacity. The lower plot shows storage discharge to meet load during those three periods and also shows that the storage is charged starting just before midnight and ending late at night during the times when system load is lower.

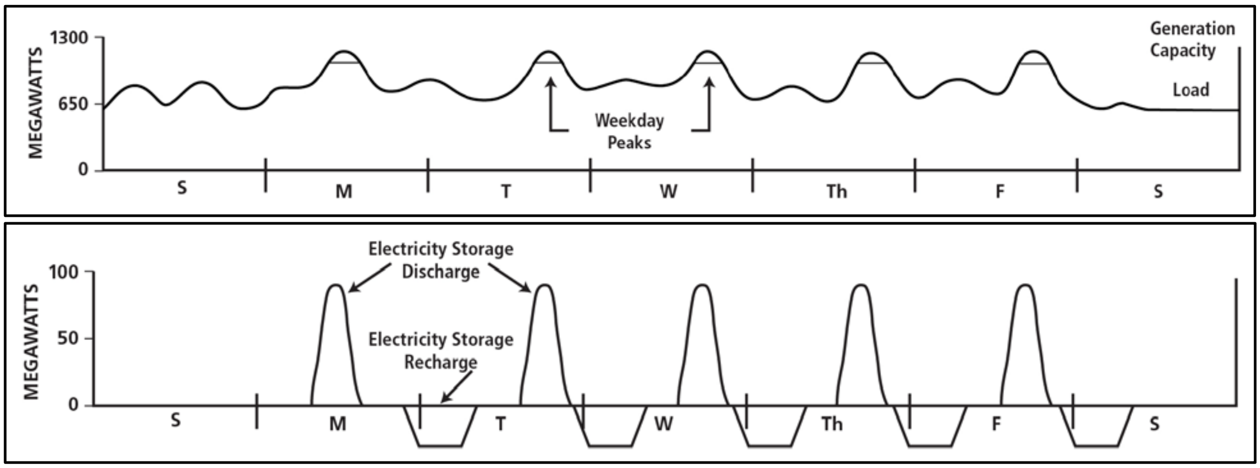

Figure 2. Storage for Electric Supply Capacity

1.2 Ancillary Services

1.2.1 Regulation

Regulation is one of the ancillary services for which storage is especially well-suited. Regulation involves managing interchange flows with other control areas to match closely the scheduled interchange flows and momentary variations in demand within the control area. The primary reasons for including regulation in the power system are to maintain the grid frequency and to comply with the North American Electric Reliability Council’s (NERC’s) Real Power Balancing Control Performance (BAL001) and Disturbance Control Performance (BAL002) Standards.

Regulation is used to reconcile momentary differences caused by fluctuations in generation and loads. Regulation is used for damping of that difference. Consider the example shown in Figure 3. The load demand line in Figure 3 shows numerous fluctuations depicting the imbalance between generation and load without regulation. The thicker line in the plot shows a smoother system response after damping of those fluctuations with regulation.

Generating units that are online and ready to increase or decrease power as needed are used for regulation and their output is increased when there is a momentary shortfall of generation to provide up regulation. Conversely, regulation resources’ output is reduced to provide down regulation when there is a momentary excess of generation.

An important consideration in this case is that large thermal base-load generation units in regulation incur significant wear and tear when they provide variable power needed for regulation duty.

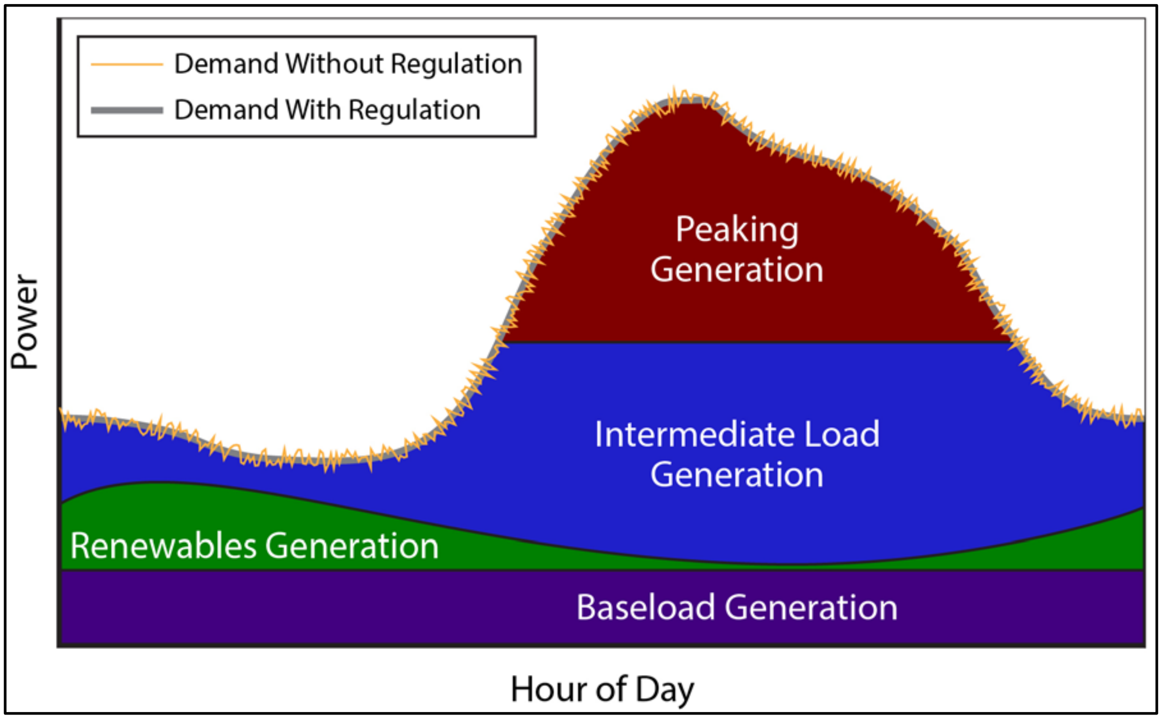

Figure 3. System Load Without and With Regulation
(Source: Sandia National Laboratories)

Two possible operational modes for 1 MW of storage used for regulation and three possible operational modes for generation used for regulation are shown in Figure 4. The leftmost plot shows how less-efficient storage could be used for regulation. In that case, increased storage discharge is used to provide up regulation and reduced discharge is used to provide down regulation. In essence, one-half of the storage's capacity is used for up regulation and the other half of the storage capacity is used for down regulation (similar to the rightmost plot, which shows how 1 MW of generation is often used for regulation service). Next, consider the second plot, which shows how 1 MW of efficient storage can be used to provide 2 MW of regulation – 1 MW up and 1 MW down – using discharging and charging, respectively.

When storage provides down regulation by charging, it absorbs energy from the grid; the storage operator must pay for that energy. That is notable – especially for storage with lower efficiency – because the cost for that energy may exceed the value of the regulation service.

Technical Considerations

Storage System Size Range: 10 – 40 MW
Target Discharge Duration Range: 15 minutes to 60 minutes
Minimum Cycles/Year: 250 – 10,000

The rapid-response characteristic (i.e., fast ramp rate) of most storage systems makes it valuable as a regulation resource. Storage used for regulation should have access to and be able to respond to the area control error (ACE) signal or an automatic generation control (AGC) signal if one is available from the Balancing Authority in which the storage system is located, as opposed to conventional plants, which generally follow an AGC signal. The equivalent benefit of regulation from storage with a fast ramp rate (e.g., flywheels, capacitors, and some battery types) is on the order of two times that of regulation provided by conventional generation,[10] due to the fact that it can follow the signal more accurately and thus reduce the total wear and tear on other generation.

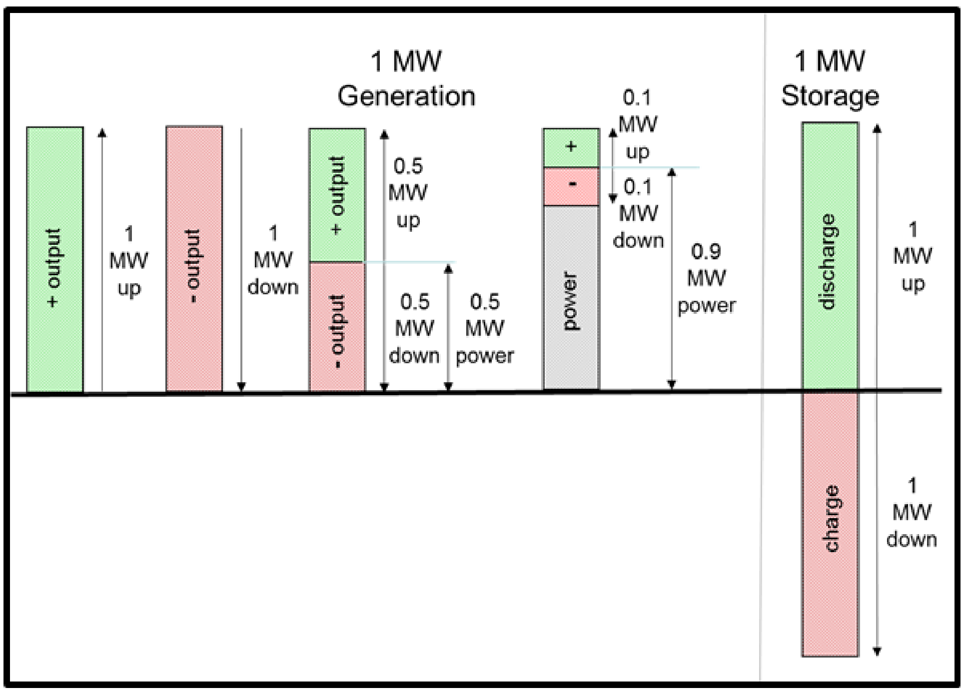

Figure 4. Storage and Generation Operation for Regulation
(Source: E&I Consulting)

Figure 5 shows two plots to illustrate the storage response for a regulation requirement. The upper plot is an exaggerated illustration of the generation variance in response to fluctuating loads. The lower plot shows storage either discharging or charging to inject or absorb the generation as needed to eliminate the need for cycling of the generation units.

[10] "*Assessing the Value of Regulation Resources Based on Their Time Response Characteristics*," Y.V. Makarov, S. Lu, J. Ma, T.B. Nguyen, PNNL-17632, Pacific Northwest National Laboratory, Richland, WA, June 2008.

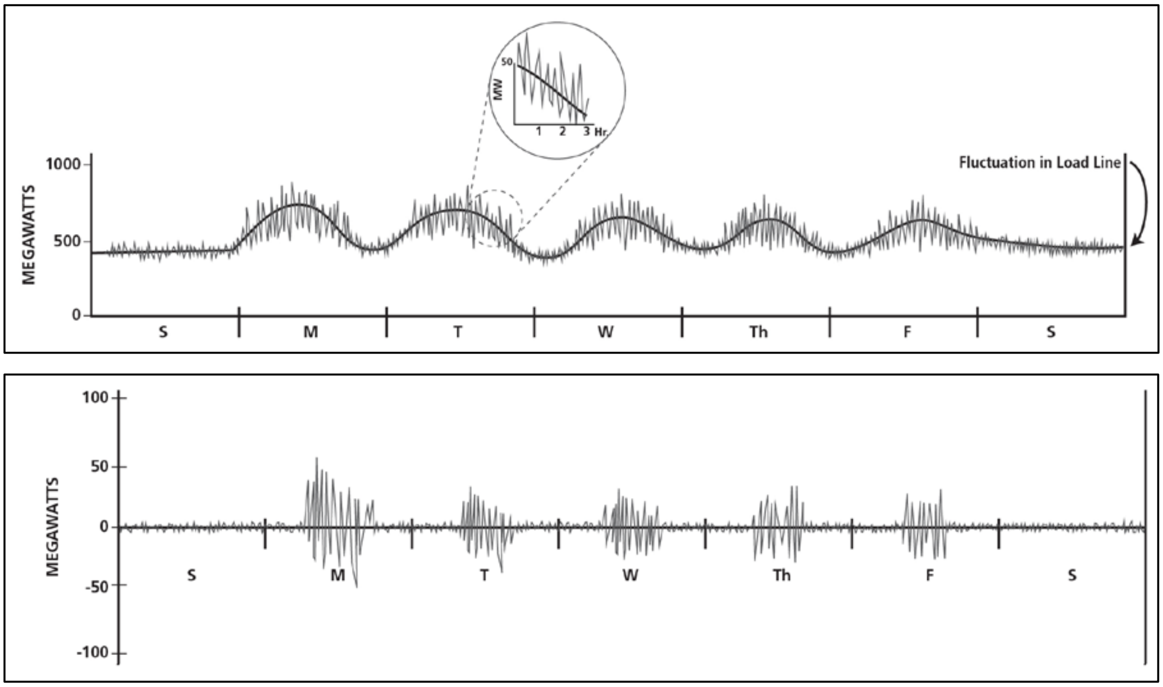

Figure 5. Storage for Regulation

1.2.2 Spinning, Non-Spinning, and Supplemental Reserves

Operation of an electric grid requires reserve capacity that can be called upon when some portion of the normal electric supply resources become unavailable unexpectedly.

Generally, reserves are at least as large as the single largest resource (e.g., the single largest generation unit) serving the system and reserve capacity is equivalent to 15% to 20% of the normal electric supply capacity. NERC and FERC define reserves differently based on different operating conditions. For simplicity, this Handbook discusses three generic types of reserve to illustrate the role of storage in this service:

Spinning Reserve[11] **(Synchronized) –** Generation capacity that is online but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. 'Frequency- responsive' spinning reserve responds within 10 seconds to maintain system frequency. Spinning reserves are the first type used when a shortfall occurs.

[11] Spinning reserve is defined in the NERC Glossary as "Unloaded generation that is synchronized and ready to serve additional demand."

Non-Spinning Reserve[12] **(Non-synchronized) –** Generation capacity that may be offline or that comprises a block of curtailable and/or interruptible loads and that can be available within 10 minutes.

Supplemental Reserve – Generation that can pick up load within one hour. Its role is, essentially, a backup for spinning and non-spinning reserves. Backup supply may also be used as backup for commercial energy sales. Unlike spinning reserve capacity, supplemental reserve capacity is not synchronized with grid frequency. Supplemental reserves are used after all spinning reserves are online.

Importantly for storage, generation resources used as reserve capacity must be online and operational (i.e., at part load). Unlike generation, in almost all circumstances, storage used for reserve capacity does not discharge at all; it just has to be ready and available to discharge when needed.

Technical Considerations

Storage System Size Range: 10 – 100 MW
Target Discharge Duration Range: 15 minutes – 1 hour
Minimum Cycles/Year: 20 – 50

Reserve capacity resources must receive and respond to appropriate control signals. Figure 6 shows how storage responds to spinning reserve requirements. The upper plot shows a loss of generation and the lower plot shows the immediate response with a 30-minute discharge to provide the reserve capacity until other generation is brought online.

[12] Non-spinning reserve is not uniformly the same in different reliabiity regions. It generally consists of generation resources that are offline, but could be brought online within 10 to 30 minutes and could also include loads that can be interrupted in that time window.

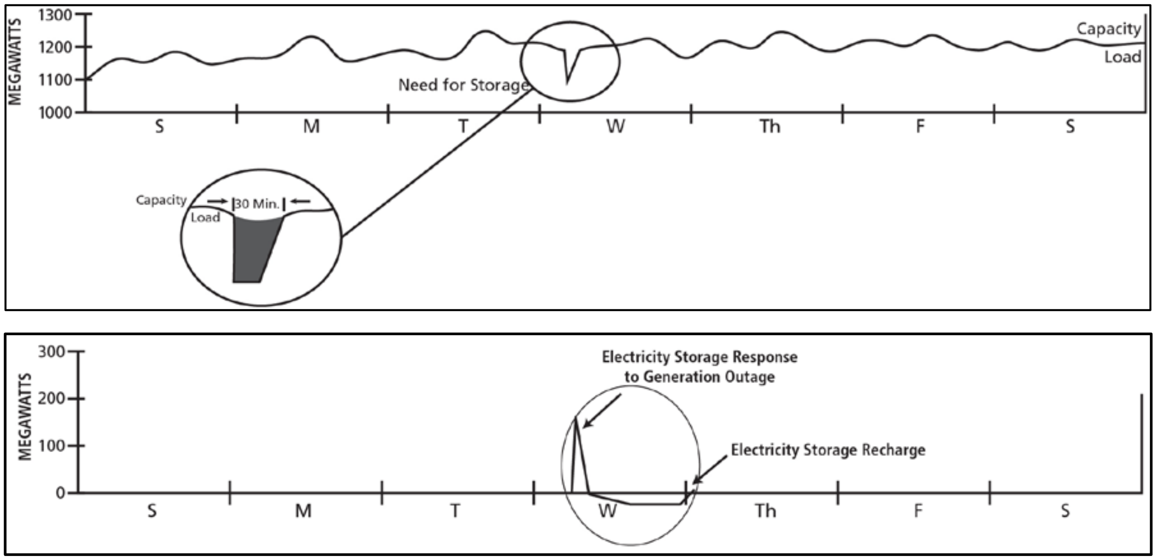

Figure 6. Storage for Reserve Capacity

1.2.3 Voltage Support

A requirement for electric grid operators is to maintain voltage within specified limits. In most cases, this requires management of reactance, which is caused by grid-connected equipment that generates, transmits, or uses electricity and often has or exhibits characteristics like those of inductors and capacitors in an electric circuit. To manage reactance at the grid level, system operators need voltage support resources to offset reactive effects so that the transmission system can be operated in a stable manner.

Normally, designated power plants are used to generate reactive power (VAR) to offset reactance in the grid. These power plants could be displaced by strategically placed energy storage within the grid at central locations or taking the distributed approach and placing multiple VAR-support storage systems near large loads.

Technical Considerations

Storage System Size Range: 1 – 10 mega volt-ampere reactive (MVAR)
Target Discharge Duration Range: Not Applicable
Minimum Cycles/Year: Not Applicable

The PCS of the storage systems used for voltage support must be capable of operating at a non-unity power factor, to source and sink reactive power or volt-ampere reactive (VARs). This capability is available in all PCSs used in today's storage systems. Real power is not needed from the battery in this mode of operation and thus discharge duration and minimum cycles per year are not relevant in this case.

The nominal time needed for voltage support is assumed to be 30 minutes — time for the grid system to stabilize and, if necessary, to begin orderly load shedding to match available generation. Figure 7 shows three discharges of storage: with active injection of real power and VARs, with absorbing power to balance voltage while providing VARs, and providing VARs only without real power injection or absorption as needed by the grid.

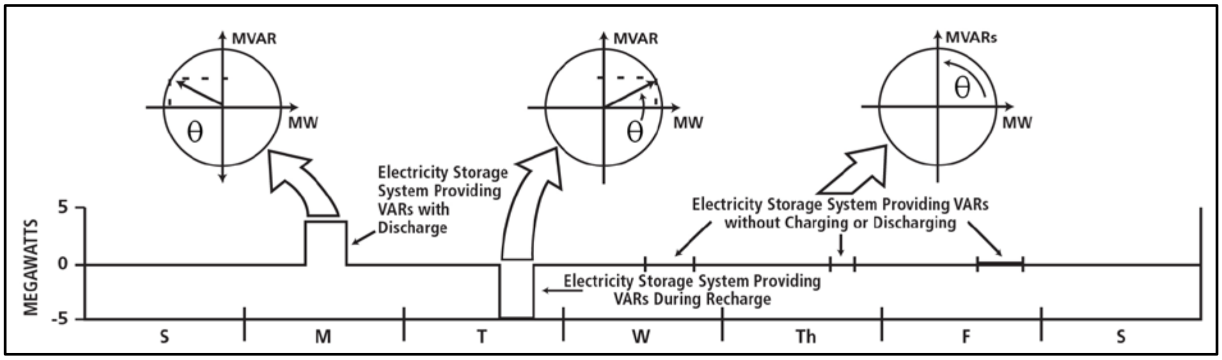

Figure 7. Storage for Voltage Support Service

1.2.4 Black Start

Storage systems provide an active reserve of power and energy within the grid and can be used to energize transmission and distribution lines and provide station power to bring power plants on line after a catastrophic failure of the grid. Golden Valley Electric Association uses the battery system in Fairbanks for this service when there is an outage of the transmission intertie with Anchorage. The operation of the battery is illustrated in Figure 8, which shows its discharge to provide charging current to two transmission paths as needed, as well as start-up power to two diesel power plants that serve Fairbanks until the intertie is restored.

Storage can provide similar startup power to larger power plants, if the storage system is suitably sited and there is a clear transmission path to the power plant from the storage system's location.

Technical Considerations

Storage System Size Range: 5 – 50 MW
Target Discharge Duration Range: 15 minutes – 1 hour
Minimum Cycles/Year: 10 – 20

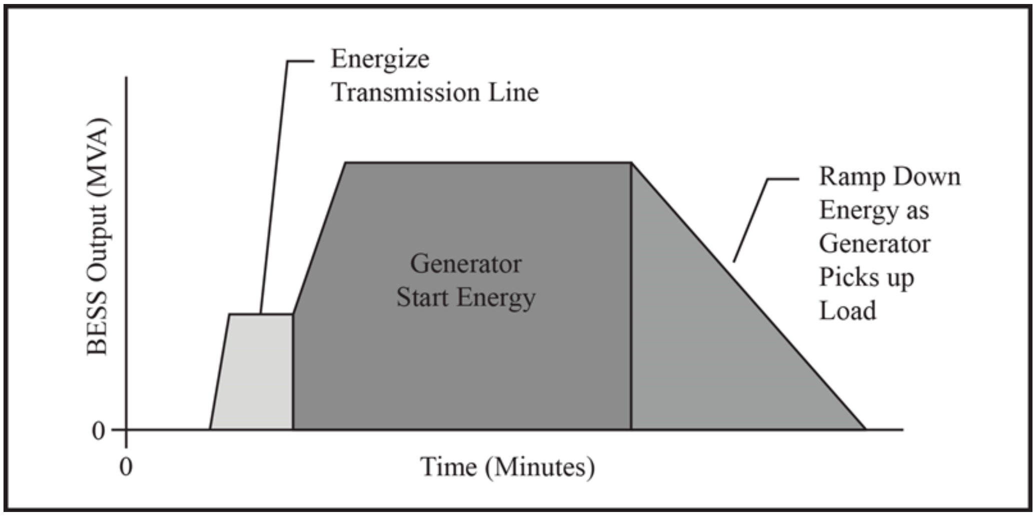

Figure 8. Black Start Service by Storage
(Courtesy: Golden Valley Electric Association)

1.2.5 Other Related Uses

1.2.5.1 Load Following/Ramping Support for Renewables

Electricity storage is eminently suitable for damping the variability of wind and PV systems and is being widely used in this application. Technically, the operating requirements for a storage system in this application are the same as those needed for a storage system to respond to a rapidly or randomly fluctuating load profile. Most renewable applications with a need for storage will specify a maximum expected up- and down-ramp rate in MW/minute and the time duration of the ramp. This design guidance for the storage system is applicable for load following and renewable ramp support; this Handbook therefore treats them as the same application.

Load following is characterized by power output that generally changes as frequently as every several minutes. The output changes in response to the changing balance between electric supply and load within a specific region or area. Output variation is a response to changes in system frequency, timeline loading, or the relation of these to each other that occurs as needed to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.

Conventional generation-based load following resources' output *increases* to follow demand up as system load increases. Conversely, load following resources' output *decreases* to follow demand down as system load decreases. Typically, the amount of load following needed in the up direction (load following up) increases each day as load increases during the morning. In the evening, the amount of load following needed in the down direction (load following down) increases as aggregate load on the grid drops. A simple depiction of load following is shown in Figure 9.

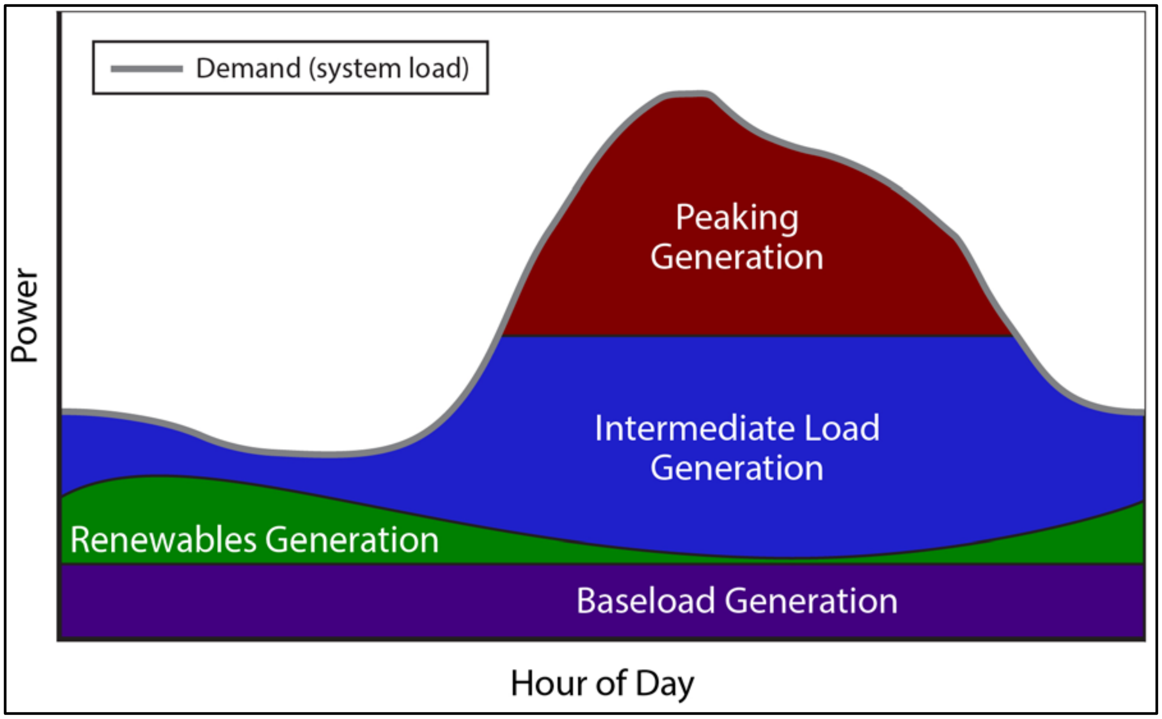

Figure 9. Electric Supply Resource Stack

Normally, generation is used for load following. For load following up, generation is operated such that its output is less than its design or rated output (also referred to as 'part load operation'). Consequently, the plant heat rates, fuel cost, and emission are increased. This allows operators to increase the generator's output, as needed, to provide load following up to accommodate increasing load. For load following down, generation starts at a high output level, perhaps even at design output, and the output is decreased as load decreases.

These operating scenarios are notable because operating generation at part load requires more fuel per megawatt hour (MWh) and results in increased air emissions per MWh relative to generation operated at its design output level. Varying the output of generators (rather than operating at constant output) will also increase fuel use and air emissions, as well as the need for generator maintenance and thus variable operations and maintenance (O&M) costs. In addition, if a fossil plant has to shut down during off-peak periods, there will be a significant increase in fuel use, O&M, and emissions. Plant reliability will also deteriorate, resulting in the need for significant purchases of replacement energy.

Storage is well-suited to load following for several reasons. First, most types of storage can operate at partial output levels with relatively modest performance penalties. Second, most types of storage can respond very quickly (compared to most types of generation) when more or less output is needed for load following. Consider also that storage can be used effectively for both load following up (as load increases) and for load following down (as load decreases), either by discharging or by charging.

In market areas, when charging storage for load following, the energy stored must be purchased at the prevailing wholesale price. This is an important consideration, especially for storage with lower efficiency and/or if the energy used for charging is relatively expensive, because the cost of energy used to charge storage (to provide load following) may exceed the value of the load following service.

Conversely, the value of energy discharged from storage to provide load following is determined by the prevailing price for wholesale energy. Depending on circumstances (i.e., if the price for the load following service does not include the value of the wholesale energy involved), when discharging for load following, two benefits accrue – one for the load following service and another for the energy.

Note that in this case, storage competes with central and aggregated distributed generation and with aggregated demand response/load management resources including interruptible loads and direct load control.

Technical Considerations

Storage System Size Range: 1 – 100 MW
Target Discharge Duration Range: 15minutes – 1 hour
Minimum Cycles/Year: Not Applicable

Storage used for load following should be reliable or it cannot be used to meet contractual obligations associated with bidding in the load following market. Storage used for load following will probably need access to AGC from the respective independent system operator (ISO). Typically, an ISO requires output from an AGC resource to change every minute.

Other considerations include synergies with other services. Large/central storage used for load following may be especially complementary to other services if the charging and discharging for the other services can be coordinated. For example, storage used to provide generation capacity mid-day could be charged in the evening, thus following diminished system demand down during evening hours.

Load following could have good synergies with renewables capacity firming, electric energy time-shift, and possibly electric supply reserve capacity applications. If storage is distributed, then that same storage could also be used for most of the distributed applications and for voltage support.

1.2.5.2 Frequency Response

Frequency response is very similar to regulation, described above, except it reacts to system needs in even shorter time periods of seconds to less than a minute when there is a sudden loss of a generation unit or a transmission line. As shown in Figure 10[13], various generator response actions are needed to counteract this sudden imbalance between load and generation to maintain the system frequency and stability of the grid. The first response within the initial seconds is the primary frequency control response of the governor action on the generation units to increase their power output as shown in the lower portion of the figure. This is followed by the longer duration secondary frequency control response by the AGC that spans the half a minute to several minutes shown by the dotted line in the lower portion of Figure 10. It is important to note that the rate at which the frequency decays after the triggering event – loss of generator or transmission – is directly proportional to the aggregate inertia within the grid at that instant. The rotating mass of large generators and/or the aggregate mass of many smaller generators collectively determines this inertia.

The combined effect of inertia and the governor actions determines the rate of frequency decay and recovery shown in the arresting and rebound periods in the upper portion of Figure 10. This is also the window of time in which the fast-acting response of flywheel and battery storage systems excels in stabilizing the frequency. The presence of fast-acting storage assures a smoother transition from the upset period to normal operation if the grid frequency is within its normal range. The effectiveness of fast-acting storage in this application has been successfully utilized by utilities[14] and also described in other reports and papers[15].

[13] *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation*, Joseph H. Eto (Principal Investigator) et al., LBNL-4142E, Lawrence Berkeley National Laboratory, Berkeley, CA, December 2010, http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf), last accessed on March 25, 2013.
[14] See BEWAG and PREPA projects in Appendix G: Noteworthy Projects.
[15] *Energy Storage – a Cheaper, Faster and Cleaner Alternative to Conventional Frequency Regulation*, a white paper by the California Energy Storage Alliance (CESA), Berkeley, CA, (http://www.ice-energy.com/stuff/contentmgr/files/1/76d44bfc1077e7fad6425102e55c0491/download/cesa_energy_storage_for_frequency_regulation.pdf), last accessed March 25, 2013.

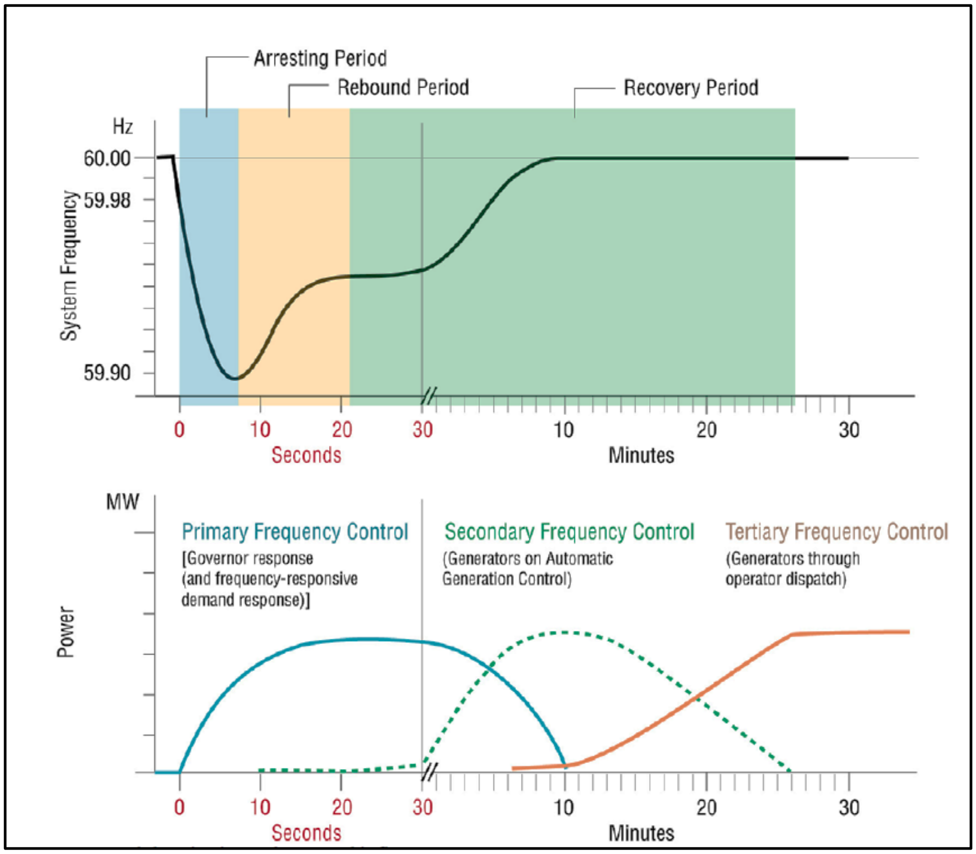

Figure 10. The Sequential Actions of Primary, Secondary, and Tertiary Frequency Controls Following the Sudden Loss of Generation and Their Impacts on System Frequency

The size of storage systems to be used in frequency response mode is proportional to the grid or balancing area in which they are needed. Generally, storage systems in the 20 MW and greater size can provide effective frequency response due to their fast action; some studies[16] have shown that the response is twice as effective as a conventional fossil-fueled generator, including combustion turbines (CTs) and coal units. However, location of the storage system within the grid with respect to other generation, transmission corridors, and loads plays a crucial role in the effectiveness as a frequency response resource.

[16] Ibid.

1.3 Transmission Infrastructure Services

1.3.1 Transmission Upgrade Deferral

Transmission upgrade deferral involves delaying – and in some cases avoiding entirely – utility investments in transmission system upgrades, by using relatively small amounts of storage. Consider a transmission system with peak electric loading that is approaching the system's load-carrying capacity (design rating). In some cases, installing a small amount of energy storage downstream from the nearly overloaded transmission node could defer the need for the upgrade for a few years.

The key consideration is that a small amount of storage can be used to provide enough incremental capacity to defer the need for a large lump investment in transmission equipment. Doing so reduces overall cost to ratepayers, improves utility asset utilization, allows use of the capital for other projects, and reduces the financial risk associated with lump investments.

Notably, for most nodes within a transmission system, the highest loads occur on just a few days per year, for just a few hours per year. Often, the highest annual load occurs on one specific day with a peak somewhat higher than any other day. One important implication is that storage used for this application can provide significant benefits with limited or no need to discharge. Given that most modular storage has a high variable operating cost, this may be especially attractive in such instances.

Although the emphasis for this application is on transmission upgrade deferral, a similar rationale applies to transmission equipment life extension. That is, if storage use reduces loading on existing equipment that is nearing its expected life, the result could be to extend the life of the existing equipment. This may be especially compelling for transmission equipment that includes aging transformers and underground power cables.

Technical Considerations

Storage System Size Range: 10 – 100 MW
Target Discharge Duration Range: 2 – 8 hours
Minimum Cycles/Year: 10 – 50

Energy storage must serve sufficient load, for as long as needed, to keep loading on the transmission equipment below a specified maximum.

Figure 11 illustrates the use of storage for transmission deferral. The lower plot shows storage being discharged on Wednesday afternoon to compensate for the high load on the substation transformer, as shown in the upper plot. The storage is recharged when the feeder load reduces in the late evening. Alternatively, the storage can be recharged during the late night as long as it is available to serve the peak load that the transformer is likely to see the following day(s).

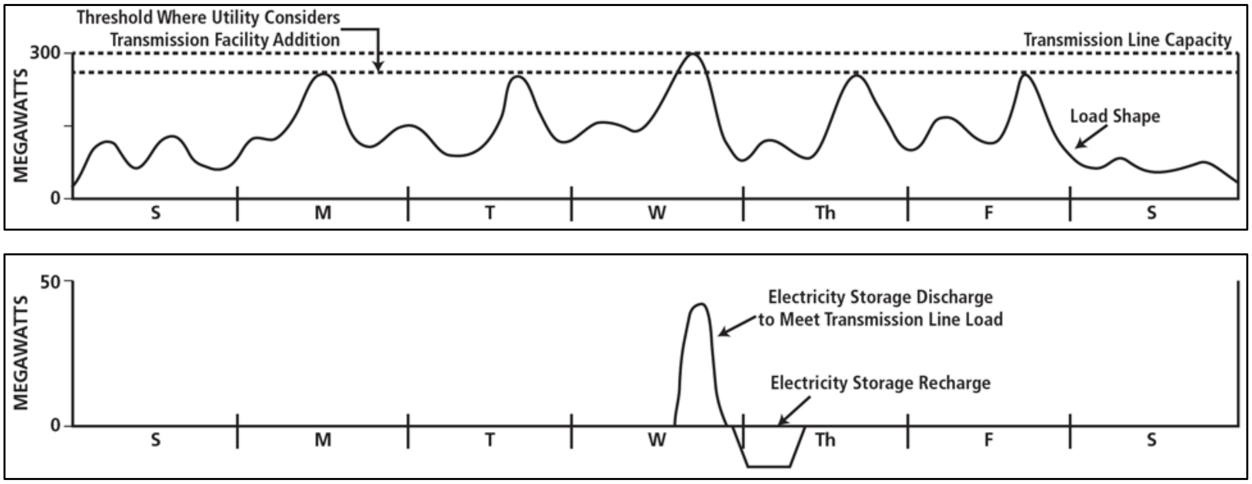

Figure 11. Storage for Transmission and Distribution Deferral

1.3.2 Transmission Congestion Relief

Transmission congestion occurs when available, least-cost energy cannot be delivered to all or some loads because transmission facilities are not adequate to deliver that energy. When transmission capacity additions do not keep pace with the growth in peak electric demand, the transmission systems become congested. Thus during periods of peak demand, the need and cost for more transmission capacity increases along with transmission access charges. Transmission congestion may also lead to increased congestion costs or locational marginal pricing (LMP) for wholesale electricity at certain transmission nodes.

Electricity storage can be used to avoid congestion-related costs and charges, especially if the costs become onerous due to significant transmission system congestion. In this service, storage systems would be installed at locations that are electrically downstream from the congested portion of the transmission system. Energy would be stored when there is no transmission congestion, and it would be discharged (during peak demand periods) to reduce peak transmission capacity requirements.

Technical Considerations

Storage System Size Range: 1 – 100 MW
Target Discharge Duration Range: 1 – 4 hours
Minimum Cycles/Year: 50 – 100

The discharge duration needed for transmission congestion relief cannot be generalized easily, given all the possible options. As with the Transmission upgrade deferral service, it may require only a few hours of support during the year when congestion relief is required. Generally, congestion charges apply for just a few occurrences during a year when there are several consecutive hours of transmission congestion.

Figure 12 illustrates the storage response in transmission congestion relief service. The upper plot shows four instances in which load exceeds the capacity of the transmission line. The lower plot shows storage discharge during those four events and a recharge during the late night when the system load is lower and the transmission line is lightly loaded.

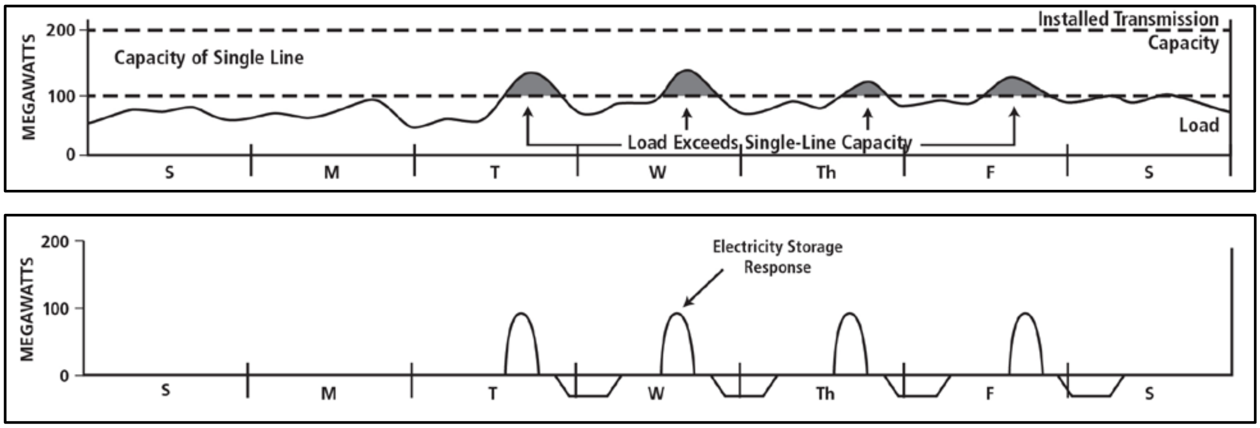

Figure 12. Storage for Transmission Congestion Relief

1.3.3 Other Related Uses

Energy storage used for transmission support improves the transmission system performance by compensating for electrical anomalies and disturbances such as voltage sag, unstable voltage, and sub-synchronous resonance. The result is a more stable system. It is similar to the network stability ancillary service that is not addressed in this Handbook. Benefits from transmission support are highly situation-specific and site-specific. Two cases are briefly described:

Transmission Stability Damping: Increase load-carrying capacity by improving dynamic stability.

Sub-synchronous Resonance Damping: Increase line capacity by allowing higher levels of series compensation by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies.

Technical Considerations

Storage System Size Range: 10 – 100 MW
Target Discharge Duration Range: 5 seconds – 2 hours
Minimum Cycles/Year: 20 – 100

Energy storage must be capable of sub-second response, partial state-of-charge operation, and many charge-discharge cycles. For storage to be most beneficial as a transmission support resource, it should provide both real and reactive power. Typical discharge durations for transmission support are between one and 20 seconds.

Figure 13 shows two plots that illustrate the storage response to momentary voltage sag and a deviation in the phase angle that persists for a few seconds, as shown in the upper plot. The storage response is a quick discharge and recharge to damp the oscillation caused by the voltage sag and phase angle deviation. As shown in the lower plot, the storage response needs to be very fast and requires high power but lower energy capacity.

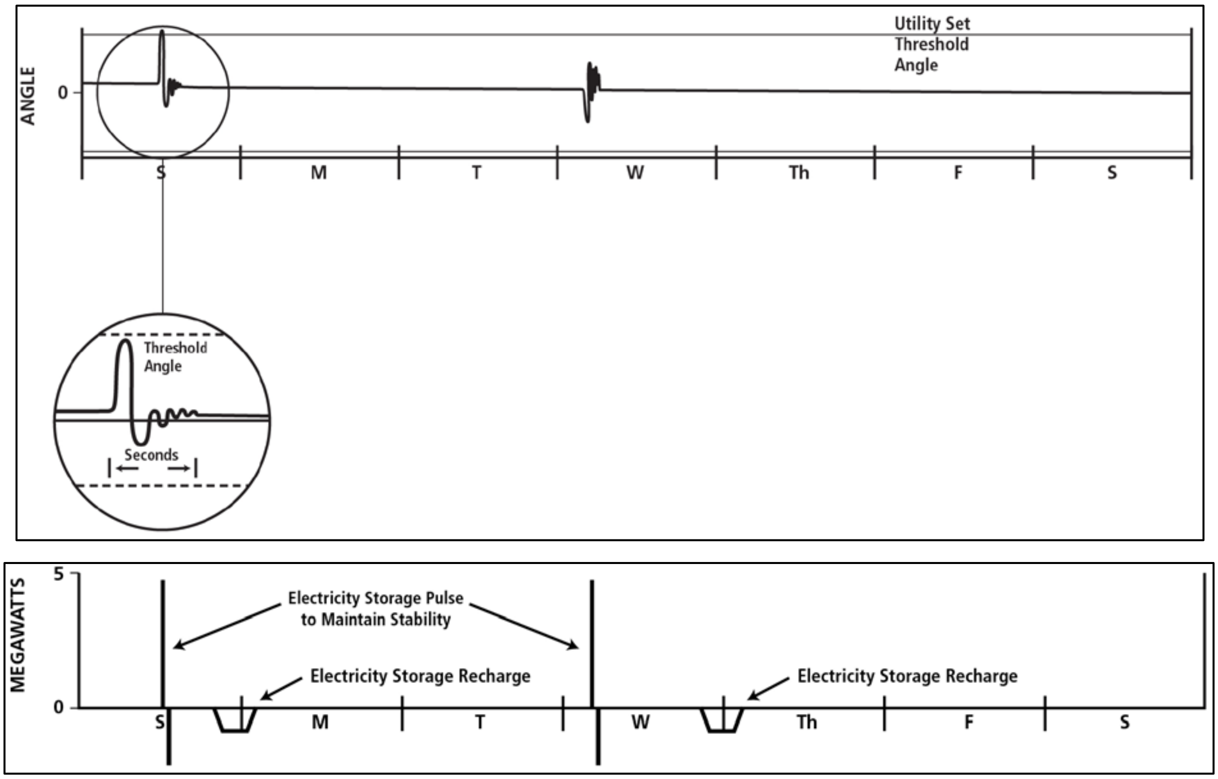

Figure 13. Storage for Customer-side Power Quality

1.4 Distribution Infrastructure Services

1.4.1 Distribution Upgrade Deferral and Voltage Support

Distribution upgrade deferral involves using storage to delay or avoid investments that would otherwise be necessary to maintain adequate distribution capacity to serve all load requirements. The upgrade deferral could be a replacement of an aging or over-stressed existing distribution transformer at a substation or re-conductoring distribution lines with heavier wire.

When a transformer is replaced with a new, larger transformer, its size is selected to accommodate future load growth over the next 15-year to 20-year planning horizon. Thus a large portion of this investment is underutilized for most of the new equipment's life. The upgrade of the transformer can be deferred by using a storage system to offload it during peak periods, thus extending its operational life by several years. If the storage system is containerized, then it can be physically moved to other substations where it can continue to defer similar upgrade decision points and further maximize the return on its investment.

A corollary to this strategy is that it also minimizes the ever-present risk that planned load growth does not occur, which would strand the investment made in upgrading the transformer or re-conductoring the line. This could be the case when a large load, such as a shopping mall or a residential development, did not materialize because the developer delayed or cancelled the project after the utility had performed the upgrade in anticipation of the new load. A storage system allows not only deferring the upgrade decision point, but also allows time to evaluate the certainty that planned load growth will materialize, which could be a two-year to three-year window.

Notably, for most nodes within a distribution system, the highest loads occur on just a few days per year, for just a few hours per year. Often, the highest annual load occurs on one specific day with a peak somewhat higher than any other day. One important implication is that storage used for this application can provide significant benefits with limited or no need to discharge.

A storage system that is used for upgrade deferral could simultaneously provide voltage support on the distribution lines. Utilities regulate voltage within specified limits[17] by tap changing regulators at the distribution substation and by switching capacitors to follow load changes. This is especially important on long, radial lines where a large load such as an arc welder or a residential PV system may be causing unacceptable voltage excursions on neighboring customers. These voltage fluctuations can be effectively damped with minimal draw of real power from the storage system.

Technical Considerations

Storage System Size Range: 500 kilowatts (kW) – 10 MW
Target Discharge Duration Range: 1 – 4 hours
Minimum Cycles/Year: 50 – 100

Figure 14 illustrates the use of storage for T&D deferral. The lower plot shows storage being discharged on Wednesday afternoon to compensate for the high load on the substation transformer, as shown in the upper plot. The storage is recharged when the feeder load reduces in the late evening. Alternatively, the storage can be recharged during the late night, as long as it is available to serve the peak load that the transformer is likely to see the following day(s).

[17] ANSI C84.1 "American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hz)" establishes nominal voltage ratings for utilities to regulate the service delivery and operating tolerances at the point of use.

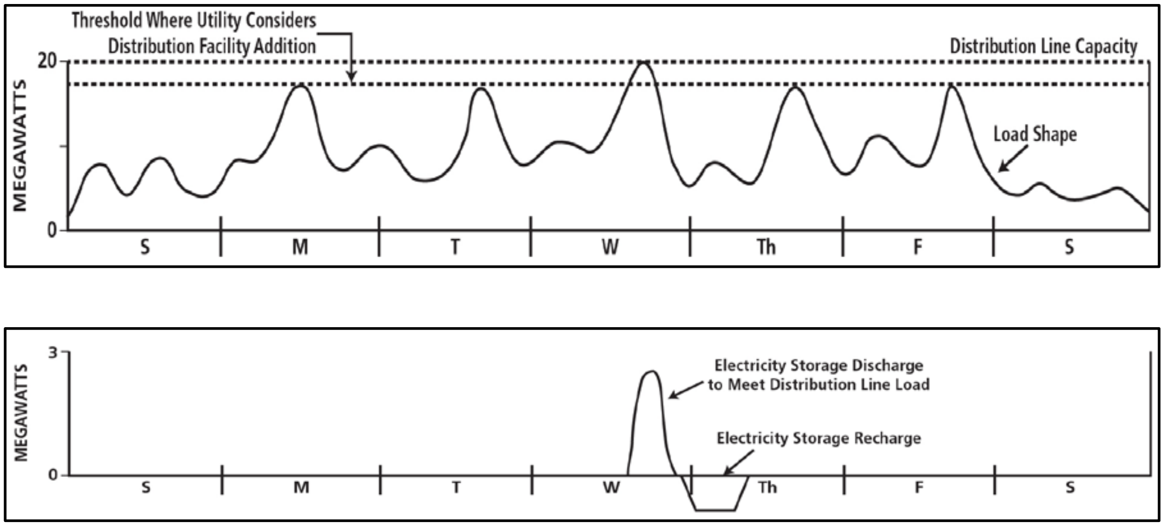

Figure 14. Storage for Distribution Upgrade Deferral

1.5 Customer Energy Management Services

1.5.1 Power Quality

The electric power quality service involves using storage to protect customer on-site loads downstream (from storage) against short-duration events that affect the quality of power delivered to the customer's loads. Some manifestations of poor power quality include the following:

- Variations in voltage magnitude (e.g., short-term spikes or dips, longer term surges, or sags).
- Variations in the primary 60-hertz (Hz) frequency at which power is delivered.
- Low power factor (voltage and current excessively out of phase with each other).
- Harmonics (i.e., the presence of currents or voltages at frequencies other than the primary frequency).
- Interruptions in service, of any duration, ranging from a fraction of a second to several seconds.

Technical Considerations

Storage System Size Range: 100 kW – 10 MW
Target Discharge Duration Range: 10 seconds – 15 minutes
Minimum Cycles/Year: 10 – 200

Typically, the discharge duration required for the power quality use ranges from a few seconds to a few minutes. The on-site storage system monitors the utility power quality and discharges to smooth out the disturbance so that it is transparent to the load.

The upper plot in Figure 15 shows a voltage spike of 50 volts (V) and the lower plot shows storage absorbing the 50V-spike to maintain a constant 480V to the load. These anomalies in the electric supply to the customer, which can occur several times in quick succession due to events in the T&D network that supplies the customer, need to be corrected to protect sensitive processes and loads at the customer site.

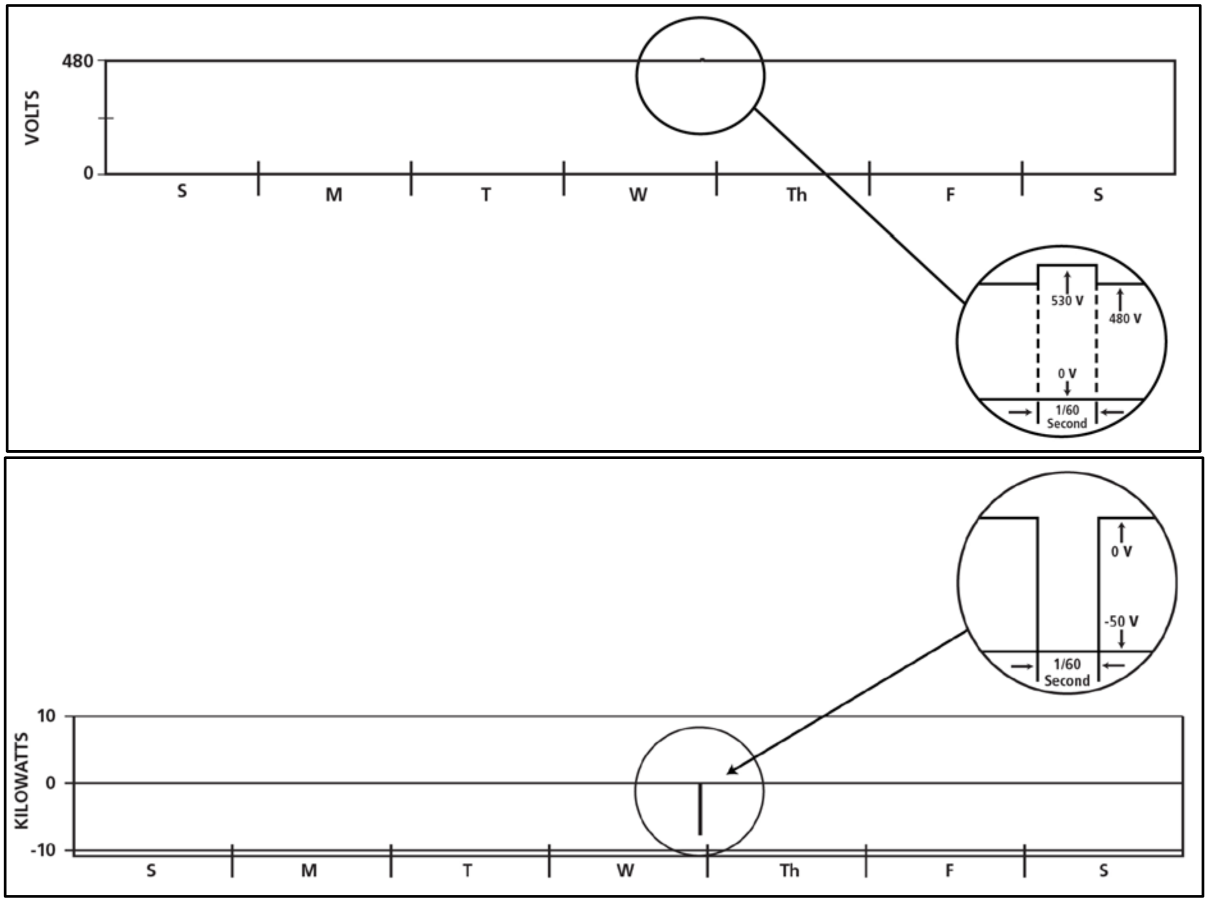

Figure 15. Storage for Customer-side Power Quality

1.5.2 Power Reliability

A storage system can effectively support customer loads when there is a total loss of power from the source utility. This support requires the storage system and customer loads to island during the utility outage and resynchronize with the utility when power is restored. The energy capacity of the storage system relative to the size of the load it is protecting determines the time duration that the storage can serve that load. This time can be extended by supplementing the storage system with on-site diesel gen-sets that can continue supporting the load for long-duration outages that are beyond the capacity of the storage system.

The storage system can be owned by the customer and is under customer control at all times. An alternate ownership scenario could be that the storage system is owned by the utility and is treated as a demand-side, dispatchable resource that serves the customer needs as well as being available to the utility as a demand reduction resource.

1.5.3 Retail Energy Time-Shift

Retail electric energy time-shift involves storage used by energy end users (utility customers) to reduce their overall costs for electricity. Customers charge the storage during off-peak time periods when the retail electric energy price is low, then discharge the energy during times when on-peak time of use (TOU) energy prices apply. This application is similar to electric energy time-shift, although electric energy prices are based on the customer's retail tariff, whereas at any given time the price for electric energy time-shift is the prevailing wholesale price.

For example, a hypothetical TOU tariff is shown in Figure 16. It applies to Commercial and Industrial electricity end users from May to October, Monday through Friday, whose peak power requirements are less than or equal to 500 kW.

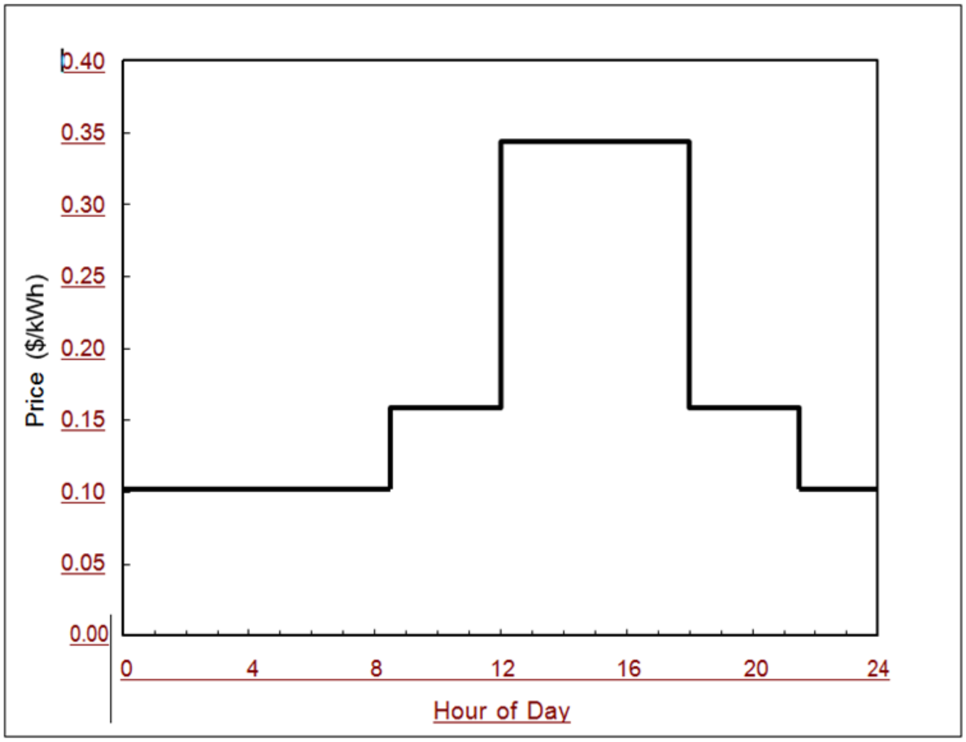

Figure 16. Time of Use Summer Energy Prices for Small Commercial/Industrial Users

As shown in Figure 16, energy prices are about 32¢/kilowatt hour (kWh) on-peak (12:00 p.m. to 6:00 p.m.). Prices during partial-peak (8:30 a.m. to 12:00 p.m. and 6:00 p.m. to 9:30 p.m.) are about 15¢/kWh, and during off-peak (9:30 p.m. to 8:30 a.m.), prices are about 10¢/kWh.

Technical Considerations

Storage System Size Range: 1 kW – 1 MW
Target Discharge Duration Range: 1 – 6 hours
Minimum Cycles/Year: 50 – 250

The maximum discharge duration in this case is determined based on the relevant tariff. For example, for the assumed hypothetical tariff, there are six on-peak hours (12:00 p.m. to 6:00 p.m.). The standard value assumed for this case is five hours of discharge duration.

1.5.4 Demand Charge Management

Electricity storage can be used by end users (i.e., utility customers) to reduce their overall costs for electric service by reducing their demand during peak periods specified by the utility.

To avoid a demand charge, load must be reduced during all hours of the demand charge period, usually a specified period of time (e.g., 11:00 a.m. to 5:00 p.m.) and on specified days (most often weekdays). In many cases, the demand charge is assessed if load is present during just one 15-minute period, during times of the day and during months when demand charges apply.

The most significant demand charges assessed are those based on the maximum load during the peak demand period (e.g., 12:00 p.m. to 5:00 p.m.) in the respective month. Although uncommon, additional demand charges for 1) part peak or (partial peak) demand that occurs during times such as shoulder hours in the mornings and evenings and during winter weekdays and 2) base-load or facility demand charges that are based on the peak demand no matter what time (day and month) it occurs.

Because there is a facility demand charge assessed during charging, the amount paid for facility demand charges offsets some of the benefit for reducing demand during times when the higher peak demand charges apply. Consider a simple example: The peak demand charge (which applies during summer afternoons, from 12:00 p.m. to 5:00 p.m.) is $10/kW-month, and the annual facility demand charge is $2/kW-month. During the night, when charging occurs, the $2/kW facility demand charge is incurred; when storage discharges mid-day (when peak demand charges apply), the $10/kW-month demand charge is avoided. The net demand charge reduction in the example is

$$\$10/\text{kW-month} - \$2/\text{kW-month} = \$8/\text{kW-month}$$

Note that the price for electric energy is expressed in $/kWh used, whereas demand charges are denominated in $/kW of maximum power draw. Tariffs with demand charges have separate prices for energy and for power (demand charges). Furthermore, demand charges are typically assessed for a given month; thus demand charges are often expressed using $/kW per month ($/kW-month).

To reduce load when demand charges are high, storage is charged when there are no or low demand charges. (Presumably, the price for charging energy is also low.) The stored energy is discharged to serve load during times when demand charges apply. Typically, energy storage can discharge for five to six hours, depending on the provisions of the applicable tariff.

Consider the example illustrated in Figure 17. The figure shows a manufacturer's load that is nearly constant at 1 MW for three shifts. During mornings and evenings, the end user's direct load and the facility's net demand are 1 MW. At night, when the price for energy is low, the facility's net demand doubles as low-priced energy is stored at a rate of 1 MW, while the normal load from the end user's operations requires another MW of power. During peak demand times (12:00 p.m. to 5:00 pm in the example), storage discharges (at the rate of 1 MW) to serve the end user's direct load of 1 MW, thus eliminating the real-time demand on the grid.

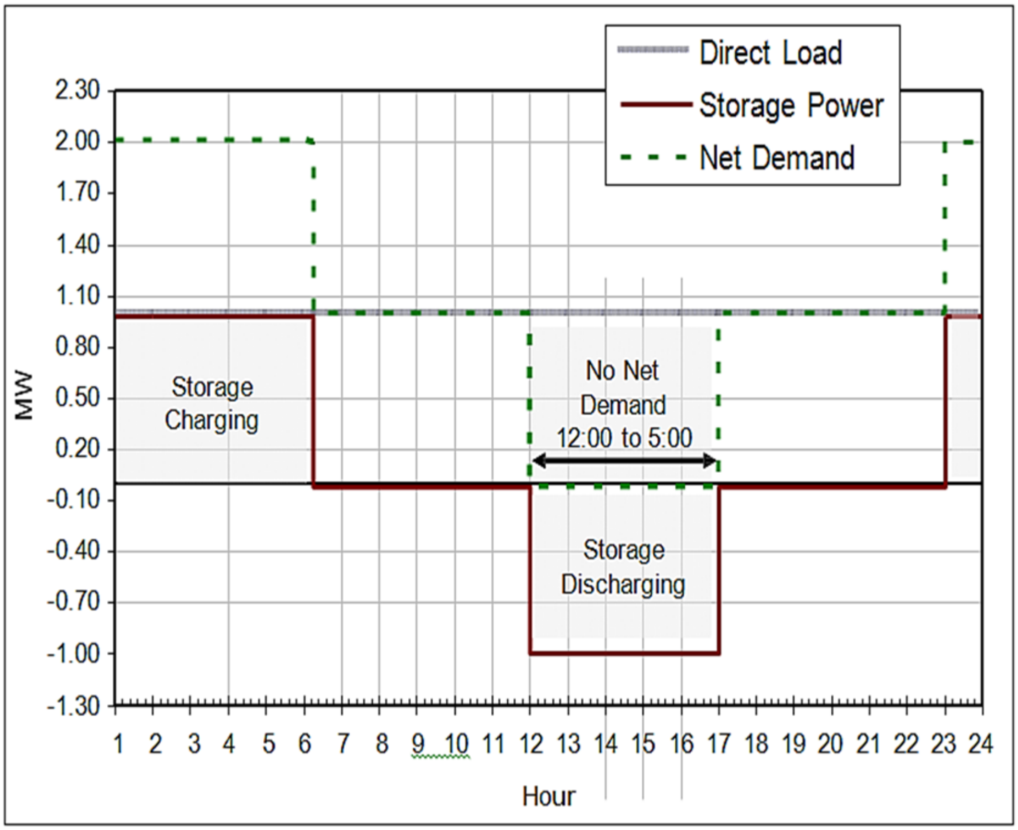

Figure 17. On-peak Demand Reduction Using Energy Storage

In the above example, storage is 80% efficient. To discharge for 5 hours, it must be charged for

$$5 \text{ hours} \div 0.8 = 6.25 \text{ hours.}$$

The additional 1.25 hours of charging is needed to offset energy losses. If a facility demand charge applies, it would be assessed on the entire 2 MW (of net demand) used to serve both load and storage charging.

Although it is the electricity customer who internalizes the benefit, in this scenario, it may be that the design, procurement, transaction cost, etc., could be challenging for many prospective users, especially those with relatively small peak loads.

Technical Considerations

Storage System Size Range: 50 kW – 10 MW
Target Discharge Duration Range: 1 – 4 hours
Minimum Cycles/Year: 50 – 500

In this example, the storage plant discharge duration is based on a hypothetical applicable tariff. For example, a hypothetical Medium General Demand-Metered TOU tariff defines six on-peak hours from 12:00 p.m. to 6:00 p.m. It is assumed that this requires five hours of storage duration.

Figure 18 shows an example where the peak loads exceed the threshold set by the first peak of the month on Monday afternoon. That sets the level for the remaining month; loads must remain below that threshold to avoid demand charge penalties.

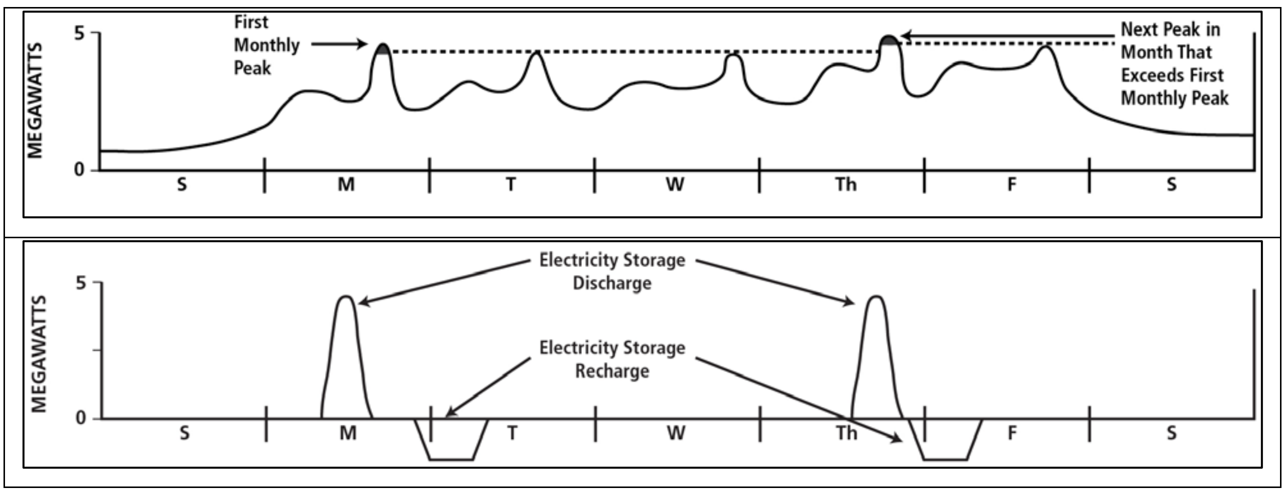

Figure 18. Storage for Customer-side Demand Management

1.6 Stacked Services—Use Case Combinations

Electricity storage can be used for any of the services listed above, but it is rare for a single service to generate sufficient revenue to justify its investment. However, the flexibility of storage can be leveraged to provide multiple or stacked services, or use cases, with a single storage system that captures several revenue streams and becomes economically viable. How these services are stacked depends on the location of the system within the grid and the storage technology used. However, due to regulatory and operating constraints, stacking services is a process that requires careful planning and should be considered on a case-by-case basis.

In the California Public Utility Commission's (CPUC's) energy storage proceeding R1012007, a series of electricity storage use cases was considered and studied by multiple stakeholders. CPUC divided the use cases into three general categories based on the location of the storage as shown in Table 2. When connected to the grid at the transmission level, energy storage can provide grid-related service to ancillary markets under the control of ISOs while bidding into the energy market. Energy storage can also act as a peaker to provide system capacity. When placed on the distribution circuits, energy storage can help solve local substation-specific problems (mitigating voltage problems, deferring investment upgrades, etc.) while providing ancillary services to the grid. On the customer side of the meter, energy storage system can shave the customer's peak load and reduce the electricity bill while improving power quality and reliability. Detailed documents about the CPUC-defined electricity storage use cases can be found on the CPUC website.[18] As part of the CPUC proceeding's effort to understand better the cost-effectiveness of different electricity storage use cases, EPRI conducted cost-benefit analyses using the Energy Storage Valuation Tool (ESVT), discussed in Chapter 3, for a subset of the CPUC use cases, including the bulk storage peaker substitution use case, the ancillary services only use case, and the distributed peaker use case. The results of the EPRI analyses[19] were presented in a public workshop in March 2013.

Table 2. Illustration of California Public Utility Commission Use Cases

(Source: EPRI presentation in CPUC Storage OIR Workshop, March 25, 2013[20])

Use Case	Categories
Transmission-Conneced Energy Storage	Bulk Storage System
	Ancillary Services
	On-Site Generation Storage
	On-Site Variable Energy Resource Storage
Distributed-Level Energy Storage	Distributed Peaker
	Distributed Storage Sited at Utility Substation
	Community Energy Storage
Demand-Side (Customer-Sited) Energy Storage	Customer Bill Management
	Customer Bill Management w/ Market Participation
	Behind the Meter Utility Controlled
	Permanent Load Shifting
	EV Charging

A detailed discussion of the methodology to determine and evaluate viable electricity storage use cases can be found in Chapter 3 of this Handbook. Various business models for acquiring storage systems can be found in Chapter 4.

[18] http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm, last accessed March 15, 2013.
[19] *Energy Storage Valuation Tool Draft Results—Investigation of Cost Effectiveness Potential for Select CPUC Inputs and Storage Use Cases in 2015 and 2020*, EPRI Energy Storage Program, CPUC Storage OIR Workshop (R.10-12-007), http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm ; last accessed March 25, 2013.
[20] Ibid.

CHAPTER 2. ELECTRICITY STORAGE TECHNOLOGIES: COST, PERFORMANCE, AND MATURITY

2.1 Introduction

This chapter presents a review of the currently available and emerging electricity storage technologies that are anticipated to be available within the next two to three years. Emerging technologies still in the early research and development (R&D) development stage are noted in the last section of this chapter but are not reviewed in detail. The sections in this chapter are organized by technology and provide a snapshot of the status, trends in deployment, data sheets on performance, and design features. Estimates of life-cycle costs for each technology are also provided, along with the key assumptions. More detailed cost breakdowns for each technology and the cost metrics are provided in Appendix B.

2.2 Storage Technologies Overview

The portfolio of electricity storage technologies can be considered for providing a range of services to the electric grid and can be positioned around their power and energy relationship. This relationship is illustrated in Figure 19, which shows that compressed air energy storage (CAES) and pumped hydro are capable of discharge times in tens of hours, with correspondingly high sizes that reach 1000 MW. In contrast to the capabilities of these two technologies, various electrochemical batteries and flywheels are positioned around lower power and shorter discharge times. In *Figure 19*, these comparisons are very general, intended for conceptual purposes only; many of the storage options have broader duration and power ranges than shown.

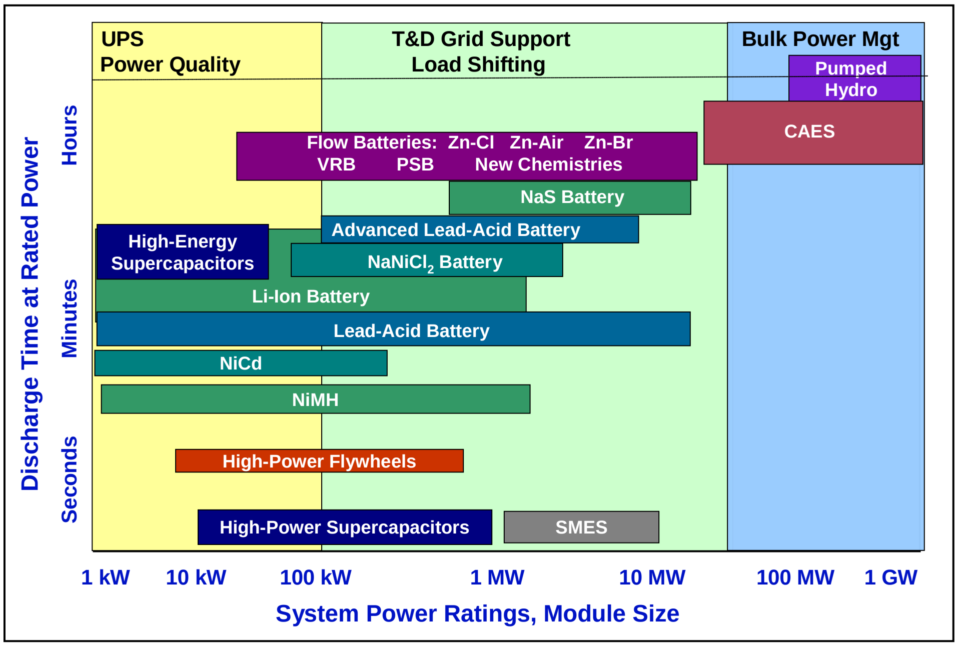

Figure 19. Positioning of Energy Storage Technologies

Traditionally, economies of scale have dictated that pumped hydro be sized for storage times that exceed 8 to 10 hours – necessary to amortize the cost of large storage reservoirs, dams, and civil engineering work that are integral to this technology. For example, Rocky Mountain Hydroelectric Plant, the last pumped storage plant built in the United States, has over 10 hours of storage capacity and is rated at 1095 MW. Similarly, CAES requires developing large underground (naturally occurring or man-made caverns) or large steel above-ground storage reservoirs to store the compressed air. In contrast to these large sizes, flywheels and the family of batteries cluster in the lower end of the discharge duration spectrum, ranging from a few seconds to 6 hours (delivered by sodium sulfur battery systems and potentially certain flow battery systems).

Storing hot or cold fluids or phase change materials provides the basis for various thermal storage technologies that provide cooling for buildings or electricity generation. Some examples of thermal storage technologies are briefly discussed below but this version of the Handbook does not specifically include the performance characteristics or system costs of these technologies.

Ice and chilled water storage is effectively used in large and medium sized commercial buildings to reduce refrigerated air conditioning loads and is widely applied in Leadership in Energy and Environmental Design (LEED)[21] certified buildings. Ice or chilled water is made and stored in large indoor or outdoor tanks using low-priced off-peak energy at night. Cooling loops running through the ice or chilled water tanks extract the cold during daytime hours to provide cooling to the building and displace the compressor and chiller motor electric loads during peak cooling hours This is a cost saving strategy for the utility or co-op customer and offers a demand-side load management strategy for the serving utility.

Alternatively, large area solar collectors can heat salts or other organic oils and store these at temperatures sufficiently high to generate steam when needed to drive turbine generators to make electricity. These systems are usually economic above several hundred megawatts, with storage times exceeding 6 to 8 hours. The size of the solar collectors and storage tank capacity determines the storage times that the system can support.

Using the Storage System Cost Information in this section comes from Appendix B and two EPRI research reports.[22,23] All costs shown are in 2012 dollars and do not reflect regional cost differences across the United States. Storage system costs have a “power” and an “energy” component. The power cost component is the cost of the power conditioning system and its auxiliaries, that determines the kW or MW capability of that particular storage system, and contributes to the $/kW component of the system cost. The energy component is the cost of the storage components – battery, flywheel, or the upper reservoir capacity in pumped hydro and

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[21] LEED is a green building certification program that recognizes best-in-class building strategies and practices administered by The U.S. Green Building Council.

[22] Energy Storage Technology and Application-Cost and Performance Data Base, EPRI ID: 1024279, EPRI, Palo Alto, CA, November 2012.

[23] Electricity Energy Storage Technology Options 2012 System Cost Benchmarking, EPRI ID: 1026462, EPRI, Palo Alto, CA, December 2012.

related aux – that determines the kWh or MWh capability of the same system and contributes to the $/kWh of the system cost. The total cost of any storage system is the sum of these components and is specific to that system size, in MW and MWh, and is not linearly scalable in most cases due to the modularity of system's design as offered by that particular system vendor. For example, if a particular system vendor offers a 4 MW/8 MWh system, then its cost in $/MW and $/MWh cannot be linearly extrapolated to a 6 MW/8 MWh system unless that or another system vendor offers such a system. However, the unit costs in $/MW or $/MWh would be the same for multiples of the 4 MW/8 MWh system.

Each storage technology described in this chapter also has system cost estimates presented in a uniformly similar bar chart format: present value installed cost, $/kW; levelized cost of energy in $/MWh and levelized cost of capacity, $/kW-yr. The information summarized in these charts is derived from the detailed cost database presented in Appendix B and interconnection equipment costs shown in Appendix D.

More than fifty original equipment manufacturers (OEMs), power electronics system providers, and system integrators were surveyed and asked to provide performance, cost, and O&M data for energy systems they could offer for various uses of storage. Reference electrical one-line diagrams and installation assessments were drawn for each use considered and are provided in Appendix D. Vendor responses to this survey provided the basis for the information in the data sheets provided in the subsequent sections. An iterative approach was used to review scope of supply, cost data, and operation and performance data. Given the lack of credible O&M data for some technologies, proxies were developed to estimate fixed, variable, and periodic battery replacement costs shown in affordably.

Given that certain energy storage technologies are still in the R&D stage and have not been fully developed or have not been demonstrated in the specifically intended service, process and project contingencies costs were added to develop installed costs, given the uncertainty in those cases.

Installed cost estimates were developed for the specific services and are presented per kilowatt of discharge capacity installed ($/kW installed). Levelized cost of energy (LCOE) or lifecycle cost estimates are expressed per kilowatt-hour ($/kWh) of delivered energy and per kW of discharge capacity ($/kW-yr). For technology screening-level studies, these cost estimates are conceptual estimates that will differ from site-specific project estimates for the following reasons:

Project estimates are more detailed and based on site-specific conditions and use cases. Individual companies' design bases may vary. Actual owner costs as well as site-specific costs in project estimates are generally higher. Site-specific requirements, such as transportation, labor, interconnection, and permitting, also have an impact.

As presented in Table 3, a rating system is used to define an overall confidence level for data presented in technology screening studies. One rating approach is based on a technology's development status; the other is based on the level of effort expended in the design and cost estimate. The confidence levels of the estimates presented in this report reflect technology development statuses ranging from early demonstration trials to mature development, with a preliminary or simplified level of effort. The rating system indicates the level of effort involved in developing the design and cost estimate.

Table 3. Confidence Rating Based on Cost and Design Estimate

Letter Rating	Key Word	Description
A	Actual	Data on detailed process and mechanical designs or historical data from existing units
B	Detailed	Detailed process design (Class III design and cost estimate)
C	Preliminary	Preliminary process design (Class II design and cost estimate)
D	Simplified	Simplified process design (Class I design and cost estimate)
E	Goal	Technical design/cost goal for value developed from literature data

Accuracy

Because of the impact of local site-specific conditions, energy storage system estimates in this report necessarily fall into the simplified or preliminary classifications. When compared with finalized or detailed cost estimate values, these may vary by 10% to 30%. However, because a consistent methodology is used for developing installed capital and levelized lifecycle cost estimates, these costs are useful in performing screening assessments for comparing various alternative storage technologies according to the service they provide.

Estimates of the range of accuracy for the cost data presented in this section are shown in Table 4, which is based on the confidence ratings described previously.

Table 4. Accuracy Range Estimates for Technology Screening Data*

		Percent Accuracy in Technology Development Rating				
	Estimate Rating	**A Mature**	**B Commercial**	**C Demo**	**D Pilot**	**E & F Lab & Idea**
A	Actual	0	–	–	–	–
B	Detailed	-5 to +8	-10 to +15	-15 to +25	–	–
C	Preliminary	-10 to +15	-15 to +20	-20 to +25	-25 to +40	-30 to +60
D	Simplified	-15 to +20	-20 to +30	-25 to +40	-30 to +50	-30 to +200
E	Goal	–	-30 to +80	-30 to +80	-30 to +100	-30 to +200
This table indicates the overall accuracy for cost estimates. The accuracy is a function of the level of cost-estimating effort and the degree of technical development of the technology. The same ranges apply to O&M costs.						

* Ranges in percent (%).

2.3 Pumped Hydro

Pumped hydroelectric energy storage is a large, mature, and commercial utility-scale technology currently used at many locations in the United States and around the world. Table 5 is a technology dashboard that shows the status of technology development for pumped hydro systems. Pumped hydro employs off-peak electricity to pump water from a reservoir up to another reservoir at a higher elevation. When electricity is needed, water is released from the upper reservoir through a hydroelectric turbine into the lower reservoir to generate electricity.

Figure 20 shows a cutaway view of a typical pumped hydro plant, and Figure 21 is a picture of the upper reservoir of the Tennessee Valley Authority's (TVA's) Raccoon Mountain pumped storage facility. This storage technology has the highest capacity of all the storage technologies assessed, because its size is limited only by the size of the available upper and lower reservoirs.

Table 5. Technology Dashboard: Pumped Hydro

Technology Development Status	**Mature**	**Numerous New Pumped Hydro FERC Filings in U.S.**
Confidence of Cost Estimate	C	Preliminary; Based on planned actual site-specific projects
Accuracy Range	Commercial	-15% to +15%
Operating Stations	40 units (20+ GW) in U.S.	Over 129 GW in operation worldwide
Process Contingency	0%	Variable-speed drive technology being applied to new sites
Project Contingency	10 – 15%	Uncertainties in sitting, permitting, environmental impact and construction

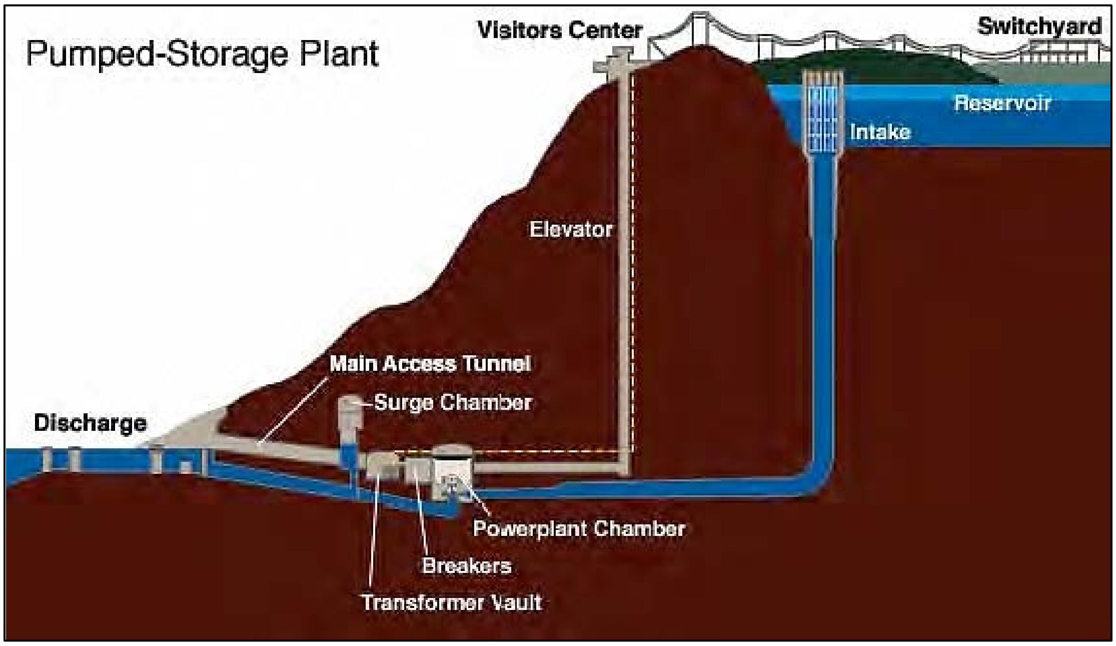

Figure 20. Cutaway Diagram of a Typical Pumped Hydro Plant

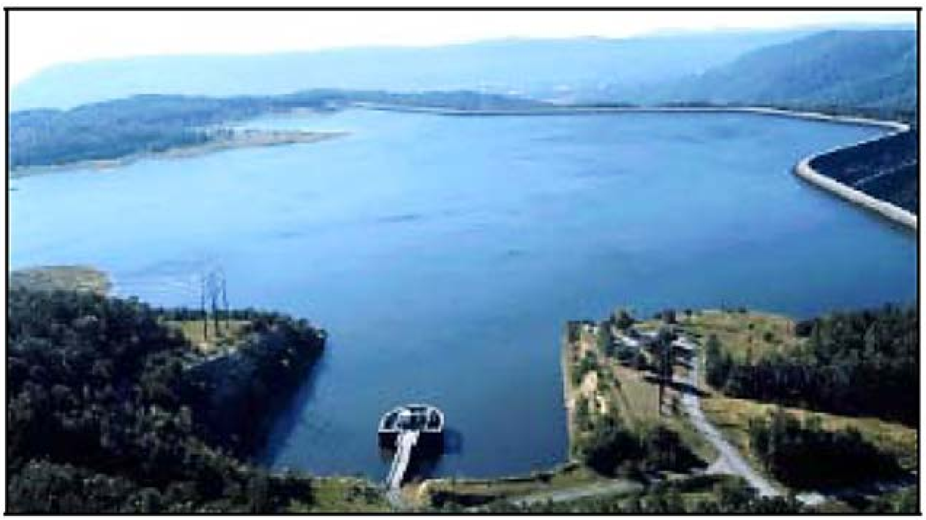

Figure 21. Man-made Upper Reservoir of TVA's Raccoon Mountain Pumped Hydro Plant
(Operational in 1979, the facility can generate 1620 MW for up to 22 hours.)

Projects may be practically sized up to 4000 MW and operate at about 76%–85% efficiency, depending on design. Pumped hydro plants have long lives, on the order of 50-60 years. As a general rule, a reservoir one kilometer in diameter, 25 meters deep, and having an average head of 200 meters would hold enough water to generate 10,000 MWh.

The earliest plant in the U.S. was built in the late 1920s, and the last pumped storage plant commissioned was in the 1980s, when environmental concerns over water and land use severely limited the ability to build additional pumped hydro capacity. Figure 22 provides a list of Pumped Storage Preliminary Permits/Proposed Projects in the United States. In Europe, over

15 GW of new pumped hydro facilities are expected to be installed by 2020, and future deployments in Asia are also expected to grow during this time period.

While the siting, permitting, and associated environmental impact processes can take many years, there is growing interest in re-examining opportunities for pumped hydro in the United States, particularly in view of the large amounts of wind generation and new nuclear power generation that may be deployed over the next few decades. A list of licensed pumped storage facilities and pending permits is maintained by FERC at http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp.

A 2011 EPRI study developed updated estimates for construction of new pumped hydro facilities.[24] Data from this study are reproduced in Figure 23 and Figure 24.

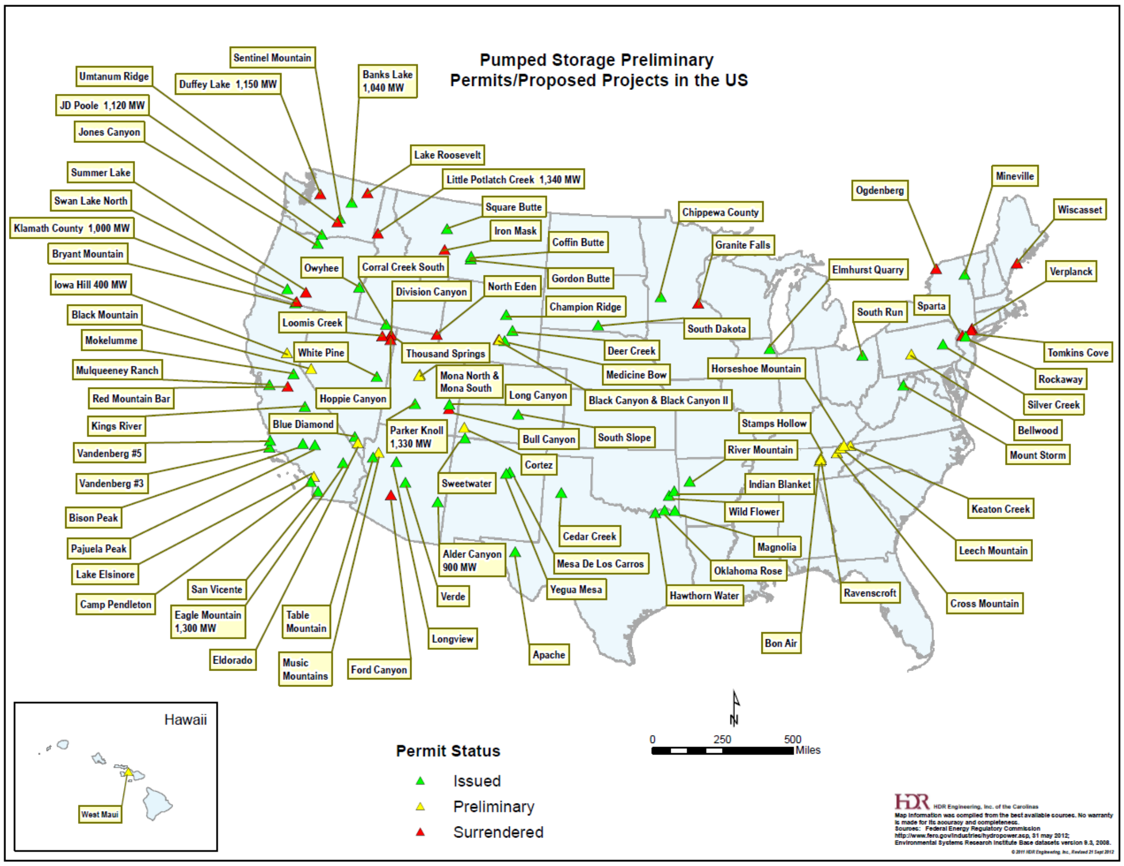

Figure 22. Pumped Storage Preliminary Permits/Proposed Projects in the United States

[24] *Quantifying the Value of Hydro Power on the Electric Grid: Plant Cost Elements*, Principal Investigators: S. Brown, J. Gibson, R. Grady, R. Miller, A. Roth, J.Sigmon, D. Summers; EPRI Report 1023140, EPRI, Palo Alto, CA, November 2011.

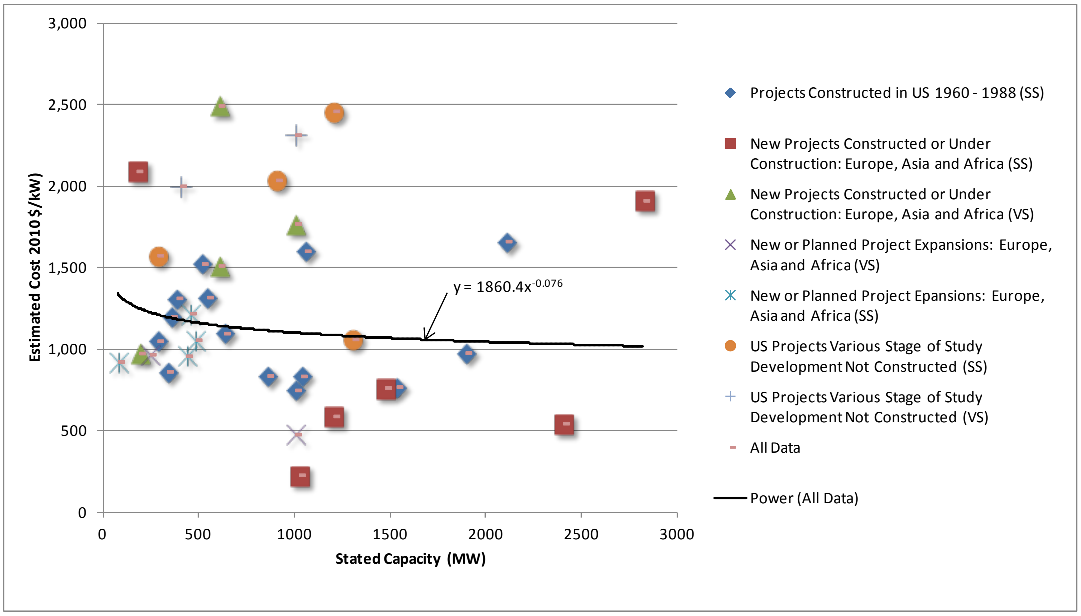

Figure 23. Cost Data ($/kW) for Historical and Proposed Pumped Hydro Projects As a Function of Capacity

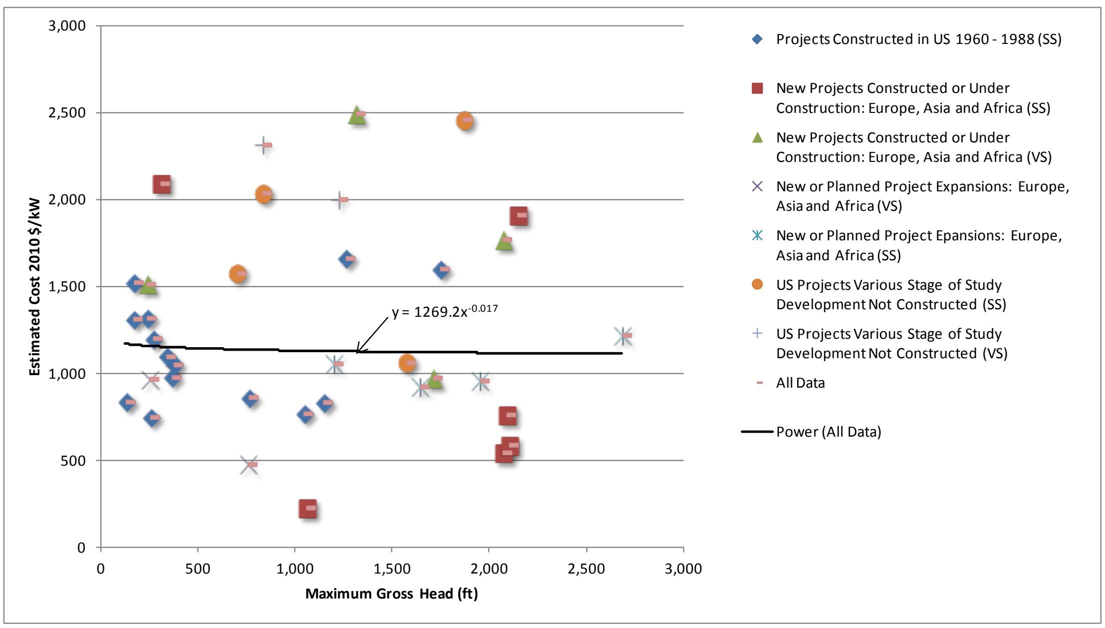

Figure 24. Cost Data ($/kW) for Historical and Proposed Storage Systems

Appendix B presents installed cost estimates for new pumped hydro stations. Pumped hydro systems are assumed to be located at greenfield sites where site-specific project costs are included in the cost estimates. This site would be typical of an unprepared or new site for a utility or a private developer that includes all the listed site-specific project costs. These estimates, then, represent an installed total plant cost (TPC) less the owner's financial costs. The utility and owner interconnection transmission line costs for pumped hydro systems are also not included in the cost estimates; however, site-specific generator step-up transformers and the site substation are included in the site-specific costs.

Pumped Hydro Life-Cycle Cost Analysis

Figure 25, Figure 26, and Figure 27 summarize present value of installed cost, the LCOE in $/MWh, and the levelized cost of capacity in $/kW-yr for pumped hydro facilities. These are based on round-trip efficiency of 81%, 365 cycles per year, and plant life of 60 years. Project-specific parameters with a more detailed economic dispatch would have different life-cycle estimates. Other assumptions and notes are shown in the detailed cost and performance tables for pumped hydro in Appendix B.

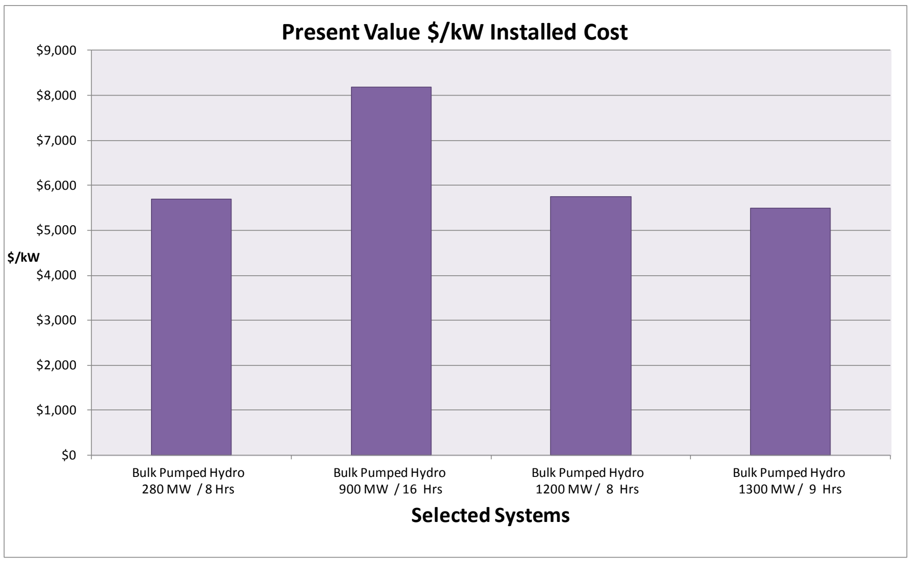

Figure 25. Present Value Installed Cost in $/kW for Pumped Hydro

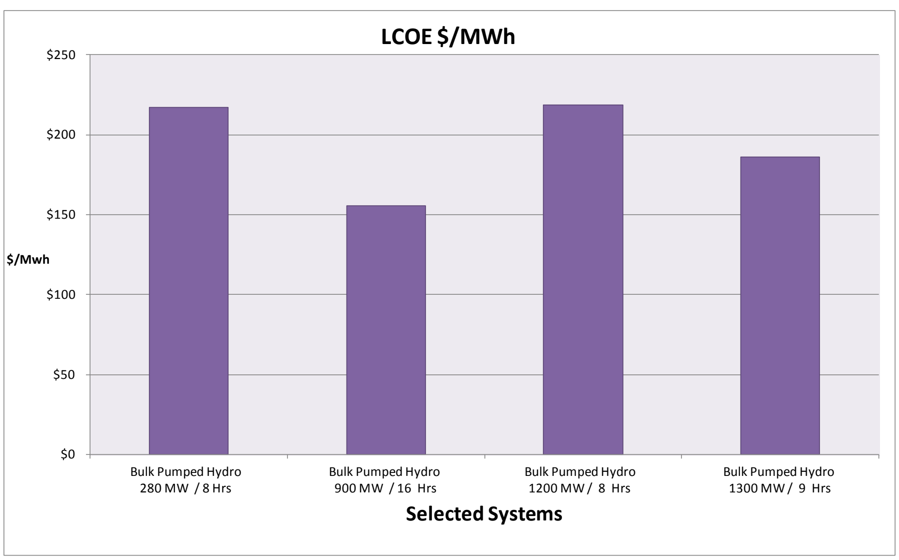

Figure 26. Levelized Cost of Energy in $/MWh for Pumped Hydro

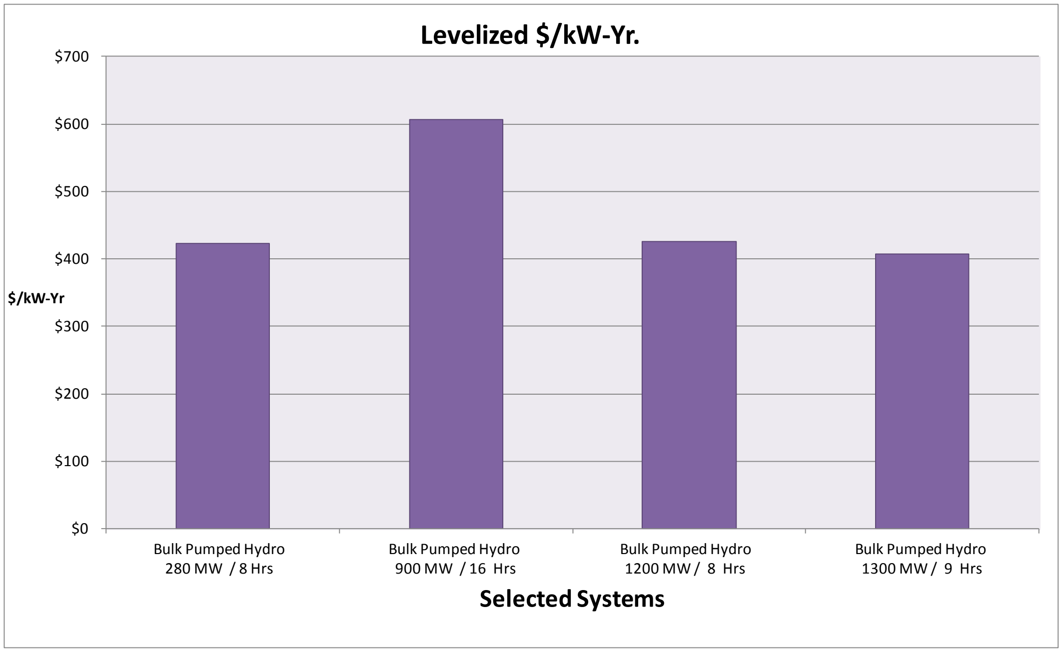

Figure 27. Levelized Cost of Capacity in $/kW-yr for Pumped Hydro

Additional Pumped Hydro Resources

1. *Quantifying the Value of Hydro Power on the Electric Grid: Plant Cost Elements*, EPRI Report 1023140, EPRI, Palo Alto, CA, November 2011.

2. *Application of Adjustable-Speed Machines in Conventional and Pumped-Storage Hydro Projects*, EPRI ID TR-105542, EPRI, Palo Alto, CA, February 1996.

3. *Operation and Maintenance Experiences of Pumped-Storage Plants*, EPRI ID GS-7325, EPRI, Palo Alto, CA, May 1991.

4. *Results from Case Studies of Pumped-Storage Plants*, EPRI ID 1023142, EPRI, Palo Alto, CA, September 2012.

2.4 Compressed Air Energy Storage

Technical Description

CAES systems use off-peak electricity to compress air and store it in a reservoir, either an underground cavern or aboveground pipes or vessels. When electricity is needed, the compressed air is heated, expanded, and directed through an expander or conventional turbine-generator to produce electricity. Figure 28 is a schematic of a CAES plant with underground storage cavern in a salt dome.

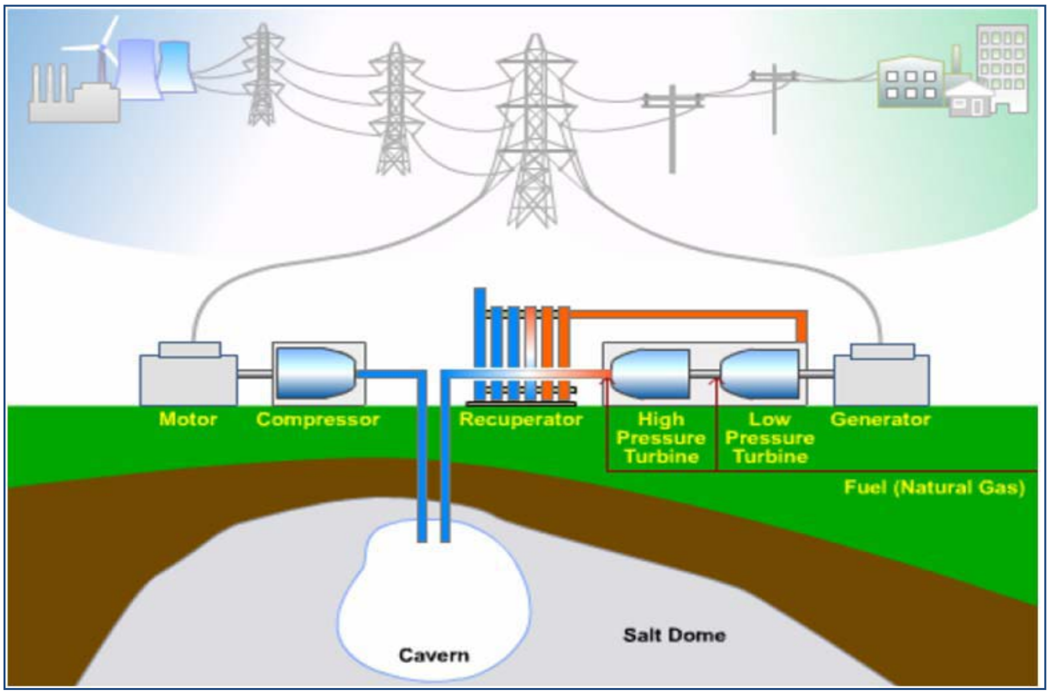

Figure 28. Schematic of Compressed Air Energy Storage Plant with Underground Compressed Air Storage

CAES is the only commercial bulk energy storage plant available today, other than pumped hydro. There are two operating first-generation systems: one in Germany and one in Alabama. In the past few years, improved second-generation CAES system cycles have been defined and are being designed. Second-generation CAES hold the potential for lower installed costs, higher efficiency, and faster construction time than the first-generation systems. In one type of advanced second-generation CAES plant, a natural-gas-fired combustion turbine (CT) is used to generate heat during the expansion process. In such a plant, about two-thirds of the electricity generated is produced from the expansion turbine and about one-third from the CT. New compressor designs and advanced turbo-machinery are also leading to improved non-CT-based CAES systems.

CAES plants employing aboveground air storage would typically be smaller than plants with underground storage, with capacities on the order of 3 to 50 MW and discharge times of 2 to 6 hours. Aboveground CAES plants are easier to site but more expensive to build (on a $/kW basis) than CAES plants using underground air storage systems, primarily due to the incremental additional cost associated with aboveground storage. CAES systems using improved first-generation designs also continue to be evaluated and are being proposed.

Underground CAES storage systems are most cost-effective with storage capacities up to 400 MW and discharge times of 8 to 26 hours. Siting such plants involves finding and verifying the air storage integrity of a geologic formation appropriate for CAES in a given utility's service territory.

Maturity and Commercial Availability

There are two operating first-generation CAES systems: one in Germany and one in the state of Alabama in the U.S. The first-generation CAES plant at PowerSouth Energy Cooperative (formerly Alabama Electric Cooperative) has operated reliably for 18 years and successfully demonstrated the technical viability of this early design. A 290-MW, four-hour CAES plant has been operating in Huntorf, Germany, since December 1978, demonstrating strong performance with 90-percent availability and 99-percent starting reliability. This plant uses two man-made, solution-mined salt caverns to store the air.

EPRI is collaborating with Pacific Gas and Electric (PG&E) in a DOE-awarded grant to support site, design, and demonstration testing of a 300-MW/10-hour CAES plant.

Table 6 is a technology dashboard that shows the status of technology development for second-generation CAES.

Table 6. Technology Dashboard: Compressed Air Energy Storage

Technology Development Status	1st Generation Mature 2nd Generation - Demonstration	Commercial offer possible. System to be verified by demonstration unit.
Confidence of Cost Estimate	C	Based on preliminary designs Owners' costs and site-specific costs not included; these costs can be significant. First-time-engineering costs can be significant.
Accuracy Range	C	-20% to +25%
Operating Field Units	2nd Generation - None	Two of first-generation type
Process Contingency	15%	Key components and controls need to be verified for second-generation systems.
Project Contingency	10%	Plant costs will vary depending upon underground site geology.

CAES Life-Cycle Cost Analysis

Figure 29, Figure 30, and Figure 31 summarize present value of installed cost, the LCOE in $/MWh, and the levelized cost of capacity in $/kW-yr for CAES plants. These estimates are based on heat rate and energy ratio and O&M data from the data sheets for CAES in Appendix B. A simple dispatch was assumed: 365 cycles per year and plant life of 30 years. Investor ownership financial assumptions are detailed in Appendix B. Natural gas cost of $3 one million Btu (MMBtu); off peak power costs of $30 megawatt hour (MWh). Project specific parameters with a more detailed economic dispatch would have different life-cycle estimates.

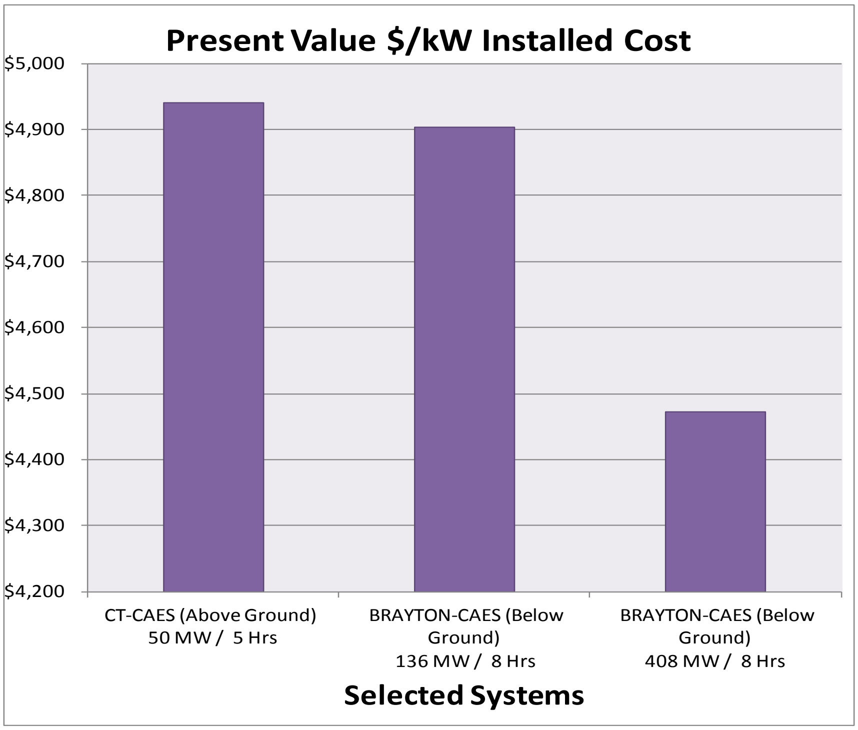

Figure 29. Present Value Installed Cost for Different Sizes of CAES Systems

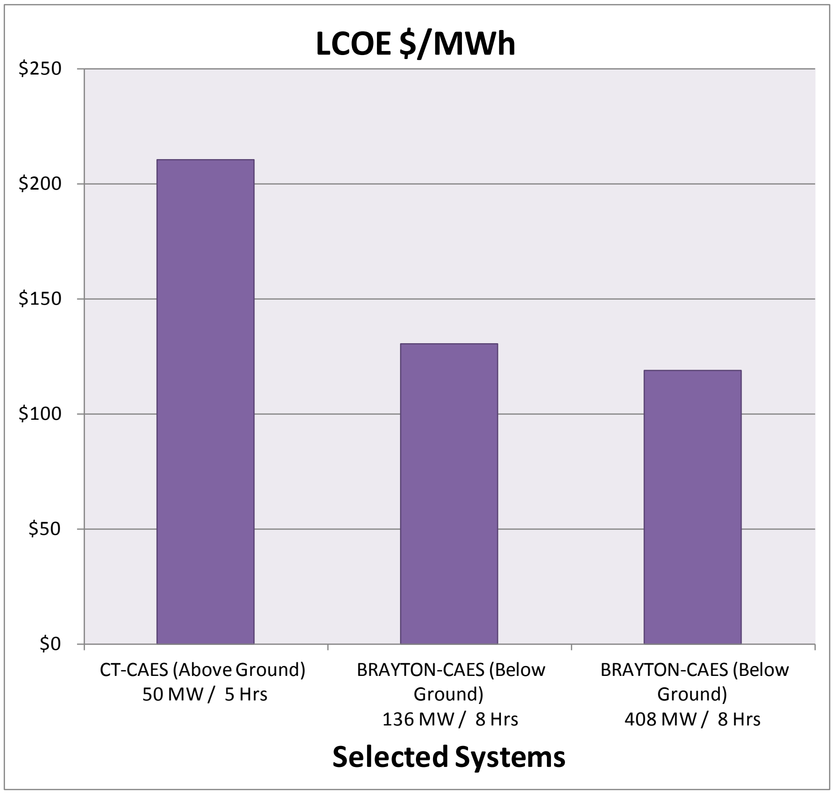

Figure 30. Levelized Costs of Energy in $/MWh for Different Sizes of CAES Systems

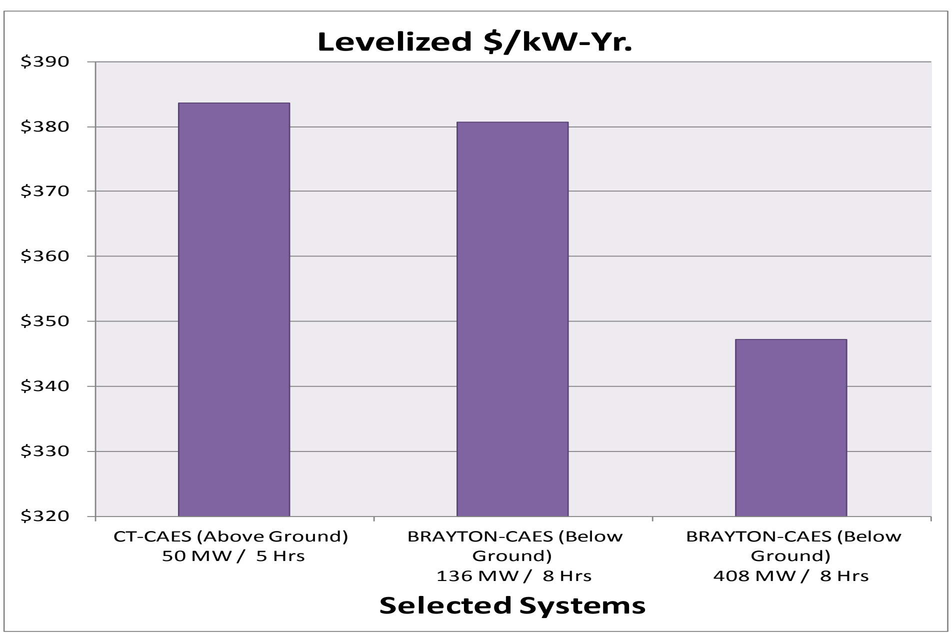

Figure 31. Levelized Costs of Capacity in $/kW-yr for Different Sizes of CAES Systems

Additional CAES Resources

1. *Electricity Storage Technology Options: A White Paper Primer on Applications*, Costs and Benefits. December 2010. EPRI Report 1020676.

2. *History of First U.S. Compressed-Air Energy Storage (CAES) Plant (110 MW 26h): Volume 2: Construction*, EPRI ID TR-101751-V2, EPRI, Palo Alto, CA, May 1994.

3. *History of First U.S. Compressed Air Energy Storage (CAES) Plant (110-MW-26 h): Volume 1: Early CAES Development*, EPRI ID 101751-V1, EPRI, Palo Alto, CA, January 1993.

4. *Midwest Independent Transmission System Operator (MISO) Energy Storage Study,* EPRI ID 1024489, EPRI, Palo Alto, CA, February 2012.

5. *Evaluation of Benefits and Identification of Sites for a CAES Plant in New York State*, EPRI TR-104268, EPRI, Palo Alto, CA, September 1994.

2.5 Sodium-sulfur Battery Energy Storage

Technical Description

Sodium-sulfur (NaS) batteries are a commercial energy storage technology finding applications in electric utility distribution grid support, wind power integration, and high-value grid services. NaS battery technology holds potential for use in grid services because of its long discharge period (approximately 6 hours). Like many other storage technologies, it is capable of prompt, precise response to such grid needs as mitigation of power quality events and response to AGC signals for area regulation.[25]

The normal operating temperature regime of NaS cells during discharge/charge cycles is in the range of 300 ºC to 350 ºC. During discharge, the sodium (negative electrode) is oxidized at the sodium/beta alumina interface, forming Na^+ ions. These ions migrate through the beta alumina solid electrolyte and combine with sulfur that is being reduced at the positive electrode to form sodium pentasulfide (Na_2S_5). The Na_2S_5 is immiscible with the remaining sulfur, thus forming a two-phase liquid mixture (Figure 32).[26]

After all the free sulfur phase is consumed, the Na_2S_5 is progressively converted into single-phase sodium polysulfides with progressively higher sulfur content (Na_2S_{5-x}). Cells undergo

[25] *Electric Energy Storage Technology Options: A Primer on Applications, Costs and Benefits*, PI: Rastler, Dan, EPRI ID 1020676, EPRI, Palo Alto, CA, September 2010. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001020676.
[26] Courtesy of EPRI.

exothermic and ohmic heating during discharge. Although the actual electrical characteristics of NaS cells are design-dependent, voltage behavior follows that predicted by thermodynamics.[27]

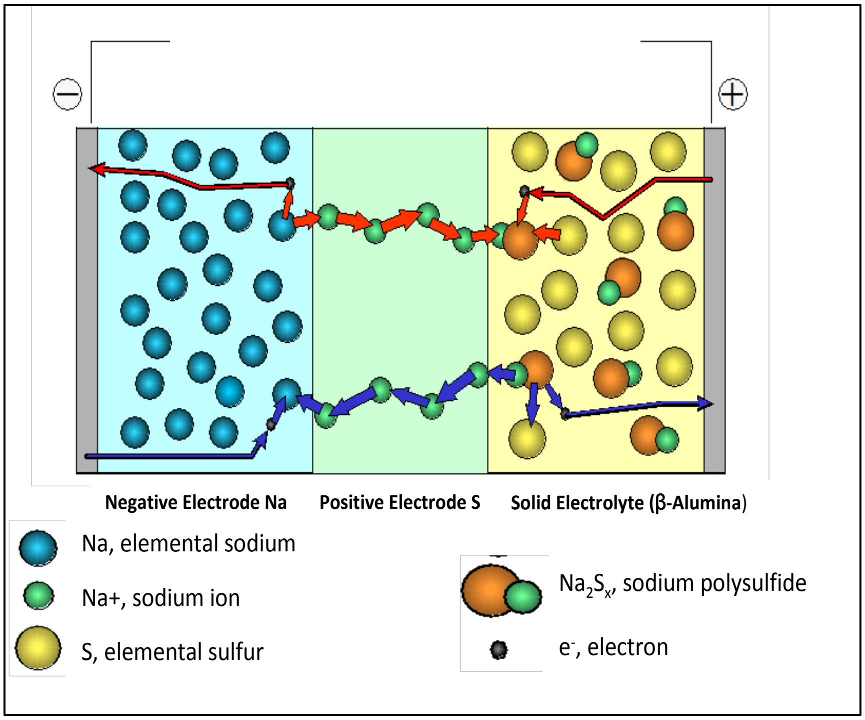

Figure 32. Chemical Structure of a Sodium-sulfur Cell

After all the free sulfur phase is consumed, the Na_2S_5 is progressively converted into single-phase sodium polysulfides with progressively higher sulfur content (Na_2S_{5-x}). Cells undergo exothermic and ohmic heating during discharge. Although the actual electrical characteristics of NaS cells are design-dependent, voltage behavior follows that predicted by thermodynamics.[28]

The NaS batteries use hazardous materials including metallic sodium, which is combustible if exposed to water. Therefore, construction of NaS batteries includes airtight, double-walled stainless-steel enclosures that contain the series-parallel arrays of NaS cells. Each cell is hermetically sealed and surrounded with sand both to anchor the cells and to mitigate fire, as shown in Figure 33. Other safety features include fused electrical isolation and a battery management system that monitors cell block voltages and temperature. The sodium, sulfur, beta-

[27] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; EPRI ID 1001834, EPRI, Palo Alto, CA, and the US Department of Energy, Washington, DC, 2003. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001001834.

[28] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; EPRI ID 1001834, EPRI, Palo Alto, CA, and the US Department of Energy, Washington, DC, 2003. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001001834.

alumina ceramic electrolyte, and sulfur polysulfide components of the battery are disposed of by routine industrial processes or recycled at the end of the NaS battery life. NaS batteries can be installed at power generating facilities, substations, and at renewable energy power generation facilities where they are charged during off peak hours and discharged when needed. Battery modules contain cells, a heating element, and dry sand.

NGK Insulators, Ltd., and Tokyo Electric Power Co. (TEPCO) jointly developed NaS battery technology over the past 25 years. "NAS" is a registered trademark for NGK's sodium-sulfur battery system, while "NaS" is a generic term used to refer to sodium-sulfur based on those elements' atomic symbols ("Na" and "S"). Standard units typically used in energy storage installations from NGK Insulators, Ltd., contain five 50-kW NaS modules that include a control unit, heater, heater controller, and voltage and current measurement sensors. Multiple, parallel standard units are used to create multi-megawatt systems.

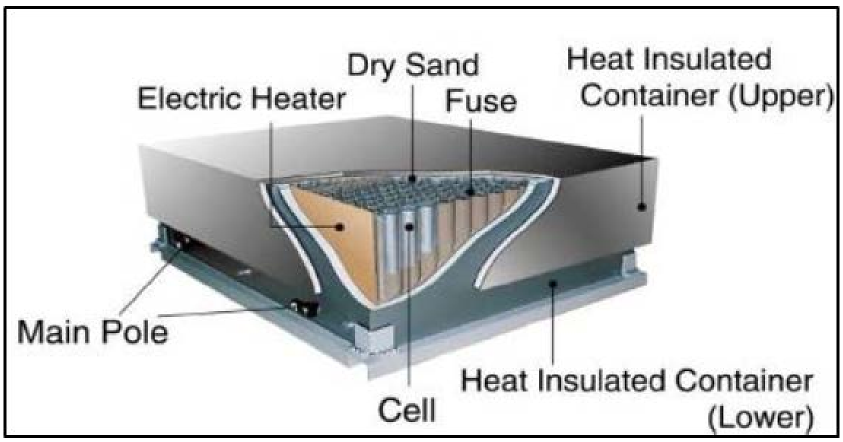

Figure 33. Sodium-sulfur Battery Module Components[29]

Performance Characteristics

Energy density by volume for NaS batteries is 170kWh/m^3 and by weight is 117kWh/ton. NGK projects its NAS to have a cycle life of 4500 cycles for rated discharge capacity of 6 MWh per installation MW. Rated at 4500 cycles, NaS batteries are projected to have a calendar life of 15 years.

[29] *1 MW / 7.2 MWh NaS Battery Demonstration and Case Study Update*,EPRI, EPRI ID: 1017814, EPRI, Palo Alto, CA: December 2009.

Table 7 summarizes the performance characteristics of NaS batteries provided by the manufacturer.

Table 7. Performance Characteristics of NaS Batteries[30]

Energy Density (Volume)	170 kWh/m^3
Energy Density (Weight)	117 kWh/ton
Charge/Discharge Efficiency – Batteries (DC Base)	> 86 percent
Charge/Discharge Efficiency – System (AC Base)	≥ 74 percent
Maintenance	Low
Cycle Life	4,500 cycles at rated capacity
Calendar Life	15 yr

Based on vendor data the round-trip alternating current (ac)-to-ac efficiency of NaS systems is approximately 75%. The estimated life of a NaS battery is approximately 15 years after 4500 cycles at rated discharge.[31]

Maturity and Commercial Availability

NaS installations providing the functional equivalent of about 160 MW of pumped hydro storage are currently deployed within Tokyo. NaS batteries are only available in multiples of 1-MW/6-MWh units with installations typically in the range of 2 to 10 MW. The largest single installation is the 34-MW Rokkasho wind-stabilization project in Northern Japan that has been operational since August 1, 2008. At this time, about 316 MW of NaS installations have been deployed globally at 221 sites, representing 1896 MWh. Customers in the United States include American Electric Power (AEP) (11 MW deployed at five locations), PG&E (6 MW, in progress), and Xcel Energy (1 MW, deployed).

The NAS battery installation provided by NGK Insulators, Ltd., deployed at Xcel in Lucerne, MN, in 2008 contains 20 50-kW modules with 7.2 MWh of storage capacity and a charge/-discharge capacity of 1 MW (Figure 34). Batteries are charged when wind turbines are operating. The batteries then provide supplemental power when the turbines are not operating. Xcel estimates the fully charged NAS facility could power 500 homes for over seven hours.

[30] Performance characteristics provided by the manufacturer, NGK.
[31] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits,* EPRI, EPRI ID: 1020676. EPRI, Palo Alto, CA, September 2010. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001020676

Figure 34. Xcel Battery Supplementing Wind Turbines, Lucerne, MN

Table 8 shows the technology dashboard for NaS battery systems.

Table 8. Technology Dashboard: Sodium-sulfur Battery Systems

Technology Development Status	A	Significant recent commercial experience.
Confidence of Cost Estimate	A	Data based on installed systems.
Accuracy Range	B	-5% to +8%
Operating Field Units	221 sites	306 MW installed.
Process Contingency	0%	Proven battery performance.
Project Contingency	1-5%	Depending on site conditions.

Sodium-sulfur Batteries Life-Cycle Cost Analysis

Figure 35, Figure 36, and Figure 37 summarize present value of installed cost, the LCOE in $/MWh, and the levelized cost of capacity in $/kW-yr for NaS plants. These estimates are based on capital and O&M data from the NaS data sheets in Appendix B. A simple dispatch was assumed: investor-owned utility financials and 365 cycles per year for 15 years. Battery replacement costs for longer service lives were not assumed over and above the O&M estimates shown in Appendix B. Key financial assumptions are also shown in Appendix B.

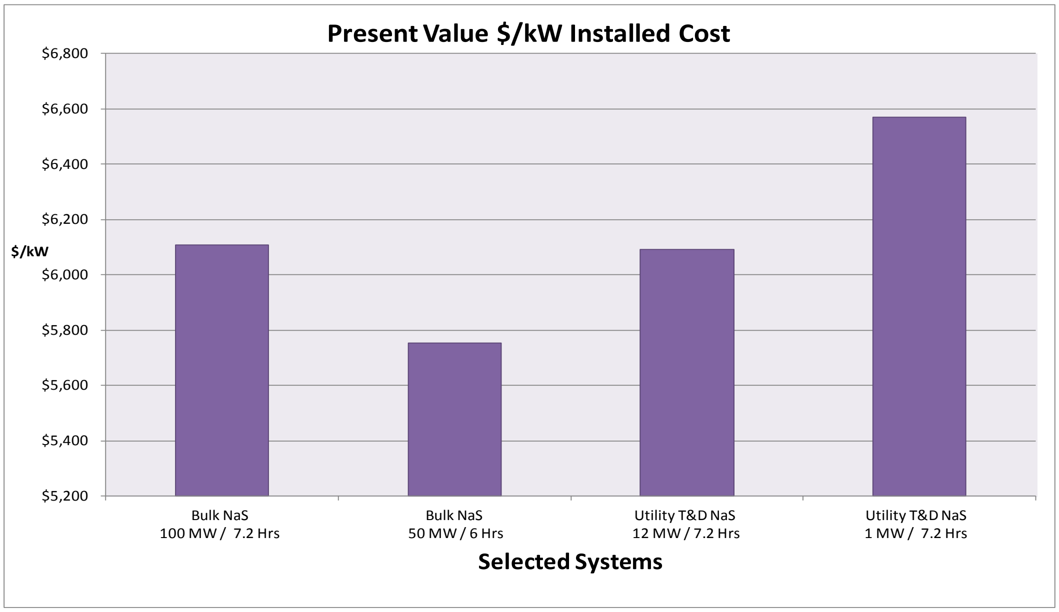

Figure 35. Present Value Installed Cost for Different Sodium-sulfur Systems

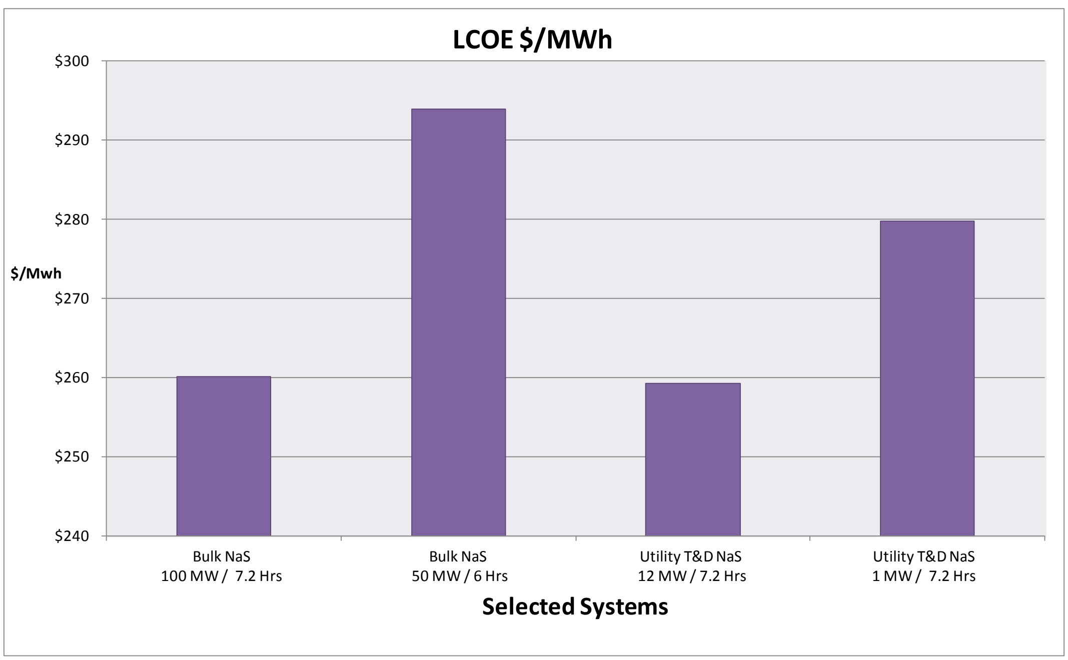

Figure 36. Levelized Cost of Energy in $/MWh for Different Sodium-sulfur Systems

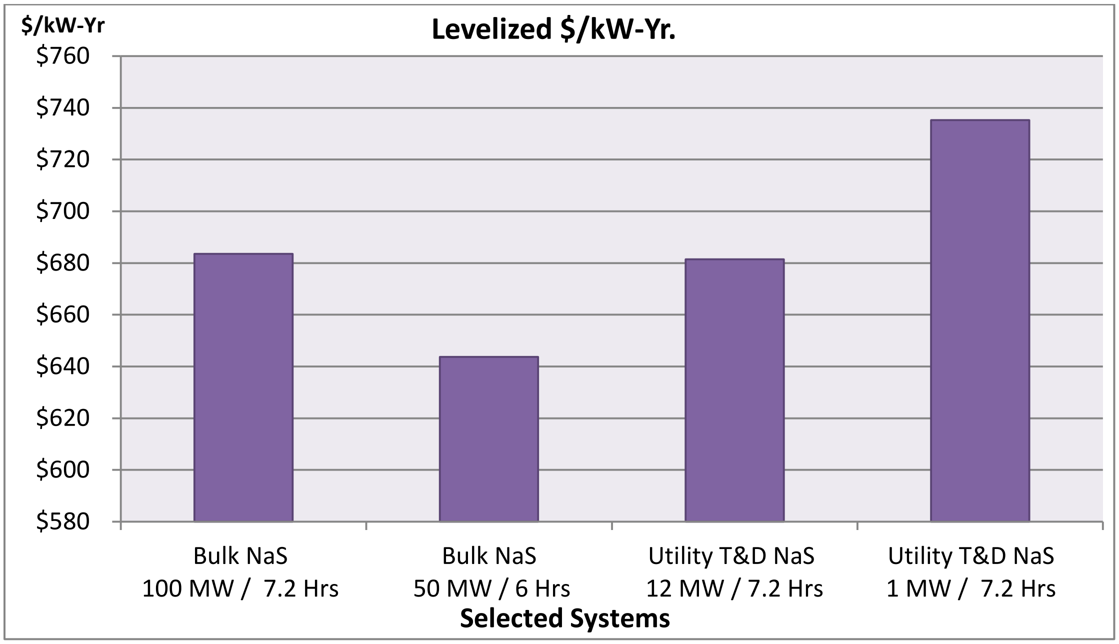

Figure 37. Levelized Costs of Capacity $/kW-yr for Different Sodium-sulfur Systems

Additional Sodium-Sulfur Battery Resources

1. *Program on Technology Innovation: Long Island Bus NaS Battery Energy Storage System*, EPRI ID 1013248, EPRI, Palo Alto, CA, EPRI ID 1013248, March 2006.

2. *Program on Technology Innovation: New York Power Authority Advanced Sodium Sulfur (NaS) Battery Energy Storage System*, EPRI ID 1023626, EPRI, Palo Alto, CA, December 2011.

3. *AEP Sodium-Sulfur (NaS) Battery Demonstration - 2003 Annual Report*, EPRI ID 1009814, EPRI, Palo Alto, CA, August 2004.

4. *AEP Sodium-Sulfur (NaS) Battery Demonstration: Final Report*, EPRI ID 1012049, EPRI, Palo Alto, CA, June 2005.

5. *Field Trial of AEP Sodium-Sulfur (NaS) Battery Demonstration Project: Interim Report - Plant Design and Expected Performance*, EPRI ID 1001835, EPRI, Palo Alto, CA, March 2003.

6. *Functional Requirements for Electric Energy Storage Applications on the Power System Grid, What Storage Has to Do to Make Sense*, EPRI ID 1021936, EPRI, Palo Alto, CA, December 2011.

2.6 Sodium-nickel-chloride Batteries

Technical Description

Sodium-nickel-chloride batteries are high-temperature battery devices like NaS. Figure 38 illustrates the design of this battery and key principles. When charging a Sodium-nickel-chloride battery at normal operating temperatures, salt (NaCl) and nickel (Ni) are transformed into nickel-chloride ($NiCl_2$) and molten sodium (Na). The chemical reactions are reversed during discharge, and there are no chemical side reactions. The electrodes are separated by a ceramic wall (electrolyte) that is conductive for sodium ions but an isolator for electrons. Therefore, the cell reaction can only occur if an external circuit allows electron flow equal to the sodium ion current. The porous solid $NiCl_2$ cathode is impregnated with a sodium ion conductive salt ($NaAlCl_4$) that provides a conductive path between the inside wall of the separator and the reaction zone. Cells are hermetically sealed and packaged into modules of about 20 kWh each.

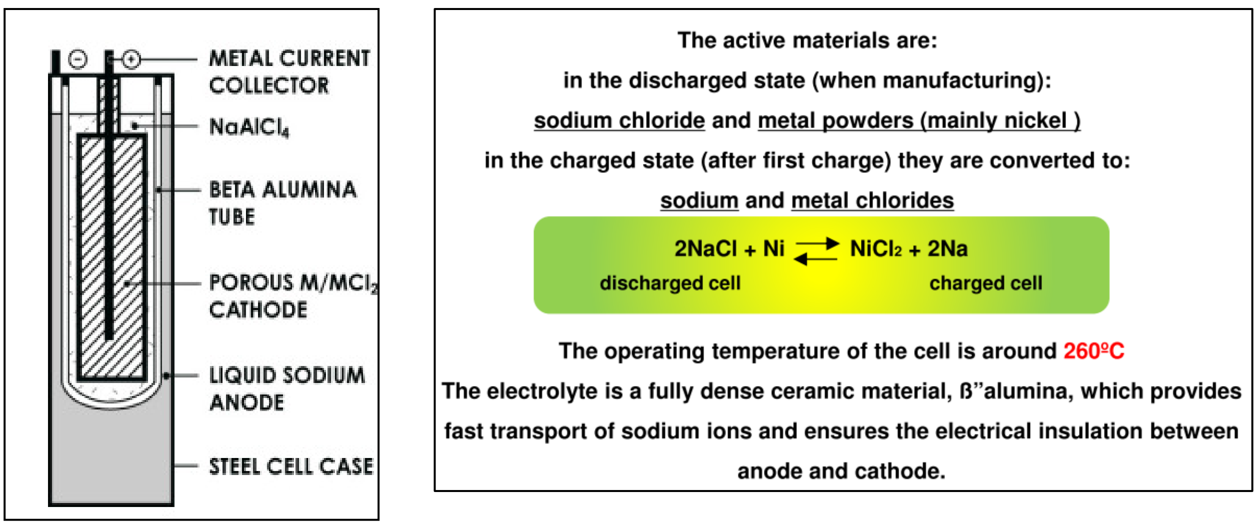

Figure 38. Design and Principal Features of Sodium-nickel-chloride Batteries
(Courtesy FIAMM)

The internal normal operating temperature of 270 °C to 350 °C is required to achieve acceptable cell resistance and must be thermally managed by design features.

Two battery original equipment manufacturer (OEM) suppliers have production facilities operating and are starting to deploy systems in the size range of 50 kW to 1 MW. By the end of 2013, several fully integrated systems are expected to be deployed for utility grid support and renewable integration.

Figure 39 and Figure 40 show two FIAMM-developed containerized systems deployed at utility sites.

Figure 39. FIAMM 222-kWh System Site at the Duke Energy Rankin Substation

Figure 40. Containerized 25 kW/50 kWh FIAMM Battery Unit (large green housing) on Concrete Pad, Next to S&C PureWave CES (small green housing)

Maturity and Commercial Availability

Table 9 presents the technology dashboard for $NaNiCl_2$ stationary storage systems.

Table 9. Technology Dashboard for Sodium-nickel-chloride Batteries

Technology Development Status	Demonstration C	Limited field demonstrations
Confidence of Cost Estimate	D	Vendor quotes and system installation estimates
Accuracy Range	C	-10% to +15%
Operating Field Units	2 or more	Several photovoltaic and distributed storage installations by 2012
Process Contingency	5 – 10%	Limited testing and filed experience
Project Contingency	5 – 10%	Limited data on life-cycle costs; limited operation and maintenance cost data

Sodium-nickel-chloride Batteries Life-Cycle Cost Analysis

Life-cycle costs of several selected $NaNiCl_2$ systems are illustrated in Figure 41, Figure 42, and Figure 43. The estimates are based on capital and O&M data from the $NaNiCl_2$ data sheets shown in Appendix B. A simple dispatch was assumed with investor-owned utility financials and 365 cycles per year for 15 years. Generally, key assumptions are investor owned utility (IOU) ownership with 365 cycles peak-shaving annually for 15 years. Cost metrics for these systems vary by vendor and related assumptions on battery replacement costs of 8 or 15 years. See Appendix B for assumptions on battery replacement costs.

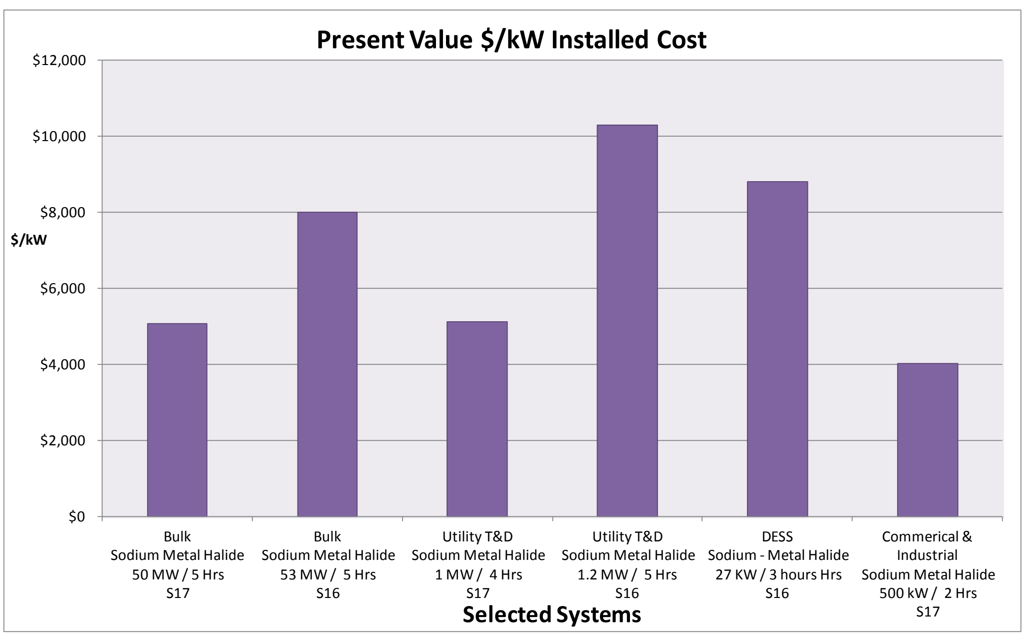

Figure 41. Present Value Installed Cost for Different Sodium-nickel-chloride Batteries
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

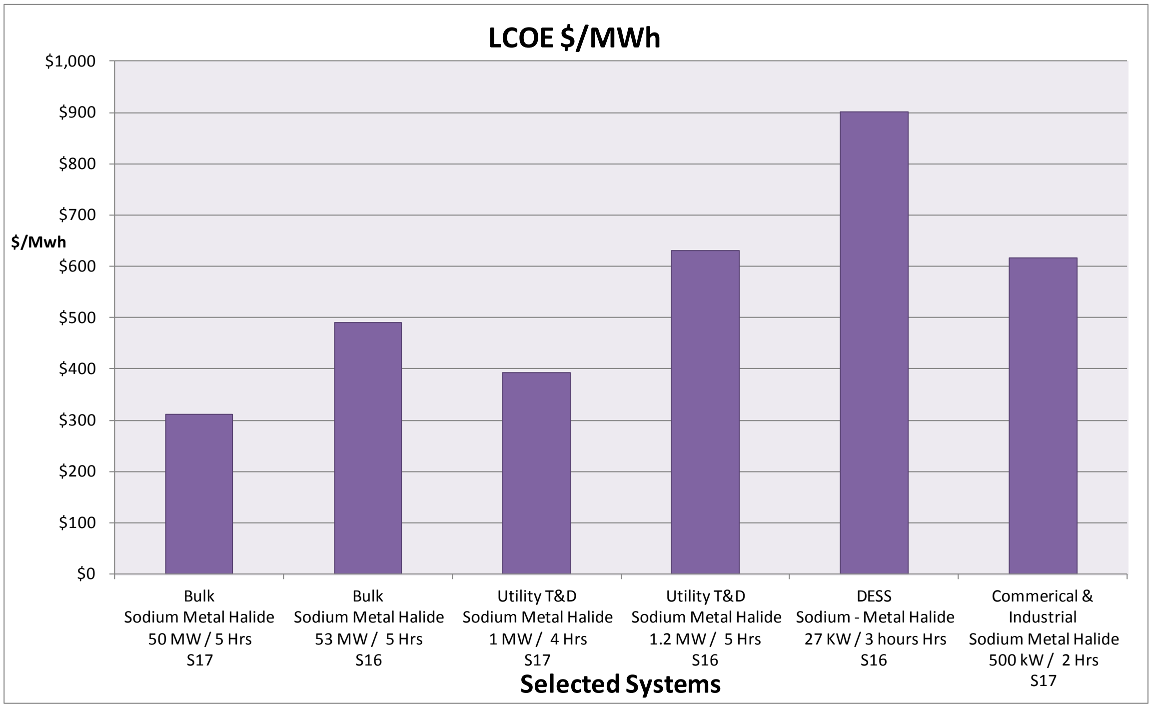

Figure 42. Levelized Cost of Energy in $/MWh for Different Sodium-nickel-chloride Batteries
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

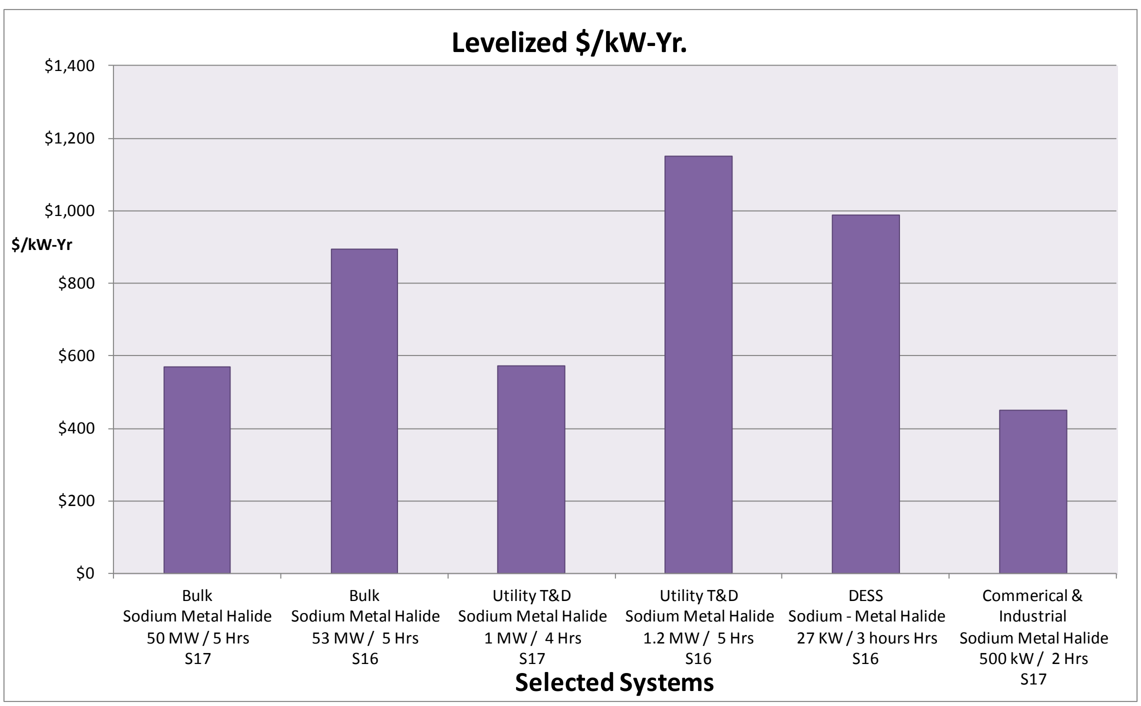

Figure 43. Levelized Cost of Capacity in $/kW-yr for Different Sodium-nickel-chloride Batteries
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

Additional Sodium-nickel-chloride Battery Resource

1. *Technology Review and Assessment of Distributed Energy Resources*, EPRI ID 1012983, EPRI, Palo Alto, CA, February 2006.

2.7 Vanadium Redox Batteries

Technical Description

Vanadium reduction and oxidation (redox) batteries are of a type known as flow batteries, in which one or both active materials is in solution in the electrolyte at all times. In this case, the vanadium ions remain in an aqueous acidic solution throughout the entire process.

The vanadium redox flow battery is a flow battery based on redox reactions of different ionic forms of vanadium. During battery charge, V3+ ions are converted to V2+ ions at the negative electrode through the acceptance of electrons. Meanwhile, at the positive electrode, V4+ ions are converted to V5+ ions through the release of electrons. Both of these reactions absorb the electrical energy put into the system and store it chemically. During discharge, the reactions run in the opposite direction, resulting in the release of the chemical energy as electrical energy.

In construction, the half-cells are separated by a proton exchange membrane that allows the flow of ionic charge to complete the electrical circuit. Both the negative and positive electrolytes (sometimes called the anolyte and catholyte, respectively) are composed of vanadium and sulfuric acid mixture at approximately the same acidity as that found in a lead-acid battery. The electrolytes are stored in external tanks and pumped as needed to the cells (see Figure 44).

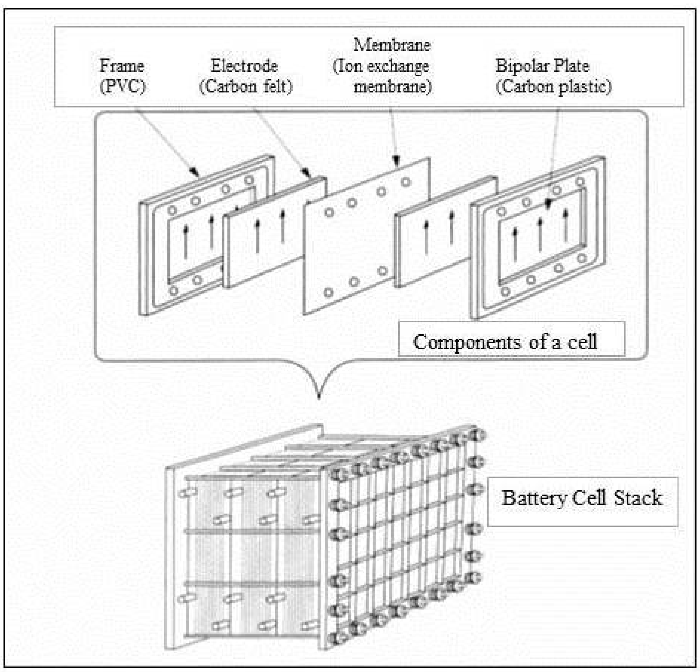

Figure 44. Construction of a Vanadium Redox Cell Stack
(Courtesy Sumitomo Electric Industries)

Individual cells have a nominal open-circuit voltage of about 1.4 V. To achieve higher voltages, cells are connected in series to produce cell stacks. Vanadium redox flow batteries have an important advantage among flow batteries: the two electrolytes are identical when fully discharged. This makes shipment and storage simple and inexpensive and greatly simplifies electrolyte management during operation.[32]

Self-discharge is typically not a problem for vanadium redox systems, because the electrolytes are stored in separate tanks. Self-discharge may occur within the cell stack if it is filled with charged electrolyte, resulting in the loss of energy and heat generation in the stacks. For this reason, the stacks are usually elevated above the tanks, so that electrolyte drains back into the tanks when the pumps are shut down. The battery will then take a short while to come back into operation again. Alternatively, the pumps can operate in an idling state, which would allow charged electrolyte to be available at all times, at the price of a slightly higher parasitic loss.[33]

The life of a vanadium redox system is determined by a number of components. The cell stack is probably the limited life component, with a useful life estimated at ~10 years; however, operational field data are not available to confirm these lifetimes. The tanks, plumbing, structure, power electronics, and controls have a longer useful life. The electrolytes and the active materials they contain do not degrade with time.

Vanadium redox systems are capable of stepping from zero output to full output within a few milliseconds, if the stacks are already primed with reactants. In fact, the limiting factor for beginning battery discharge is more commonly the controls and communications equipment. For short-duration discharges for voltage support, the electrolyte contained in the stacks can respond without the pumps running at all. The cell stack can produce three times the rated power output provided the state of charge is between 50% and 80%.[34]

The physical scale of vanadium redox systems tends to be large due to the large volumes of electrolyte required when sized for utility-scale (megawatt-hour) projects. Unlike many other battery technologies, cycle life of vanadium redox systems is not dependent on depth of discharge. Systems are rated at 10,000 cycles, although some accelerated testing performed by Sumitomo Electric Industries, Ltd., produced a battery system with one 20-kW stack for cycle testing that continued for more than 13,000 cycles over about two years.

When decommissioning a vanadium redox system, the solid ion exchange cell membranes may be highly acidic or alkaline and therefore toxic. They should be disposed of in the same manner as any corrosive material. If possible, the liquid electrolyte is recycled. If disposed of, the

[32] *VRB Energy Storage for Voltage Stabilization: Testing and Evaluation of the PacifiCorp Vanadium Redox Battery Energy Storage System at Castle Valley, Utah*, EPRI ID 1008434, EPRI, Palo Alto, CA, 2005.
[33] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC: 2003. 1001834. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001001834.
[34] Ibid.

vanadium is extracted from the electrolyte before further processing of the liquid. Research is ongoing to determine the exact environmental risk factors for vanadium.

Figure 45[35] illustrates the schematic of a vanadium redox flow battery.

Technical Maturity

Table 10 illustrates a dashboard for a vanadium flow battery system. This type of flow battery is technically the more mature battery of all the flow-type battery systems.

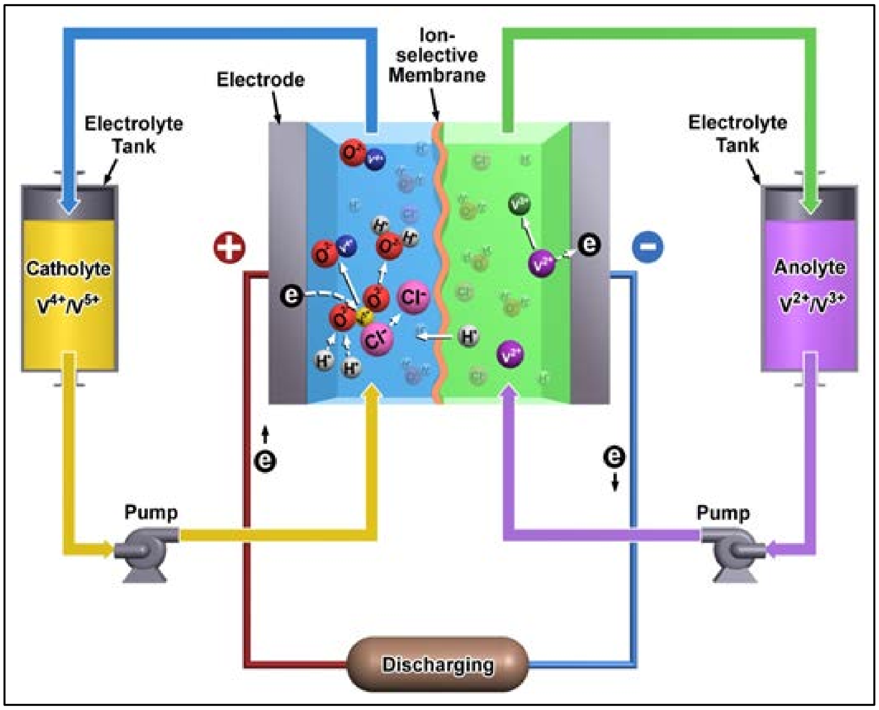

Figure 45. Principles of the Vanadium Redox Battery
(Courtesy of the Pacific Northwest National Laboratory)

[35] *VRB Energy Storage for Voltage Stabilization: Testing and Evaluation of the PacifiCorp Vanadium Redox Battery Energy Storage System at Castle Valley, Utah*, PI: Harash Kamath – EPRI PEAC Corporation, EPRI ID 1008434, EPRI, Palo Alto, CA, March 2005.

Vanadium redox systems have been demonstrated in a number of applications and large-scale field trials (see Figure 46).

Table 10. Technology Dashboard: Vanadium Flow-Type Battery Systems

Technology Development Status	Pre-Commercial C	Systems Verified in Limited Field Demonstrations
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	C	-10% to +15%
Operating Field Units	Units operating in renewable integration, end-user energy management, and telecom applications	Currently 50-kW, 100-kW, 500-kW, 600-kW, and 1000-kW systems in operation. The largest in the U.S. is a 600-kW/3600-kWh system in a customer energy-management application. A 1-MW/5-MWh system is in operation in Japan.
Process Contingency	5 – 8%	For MW-scale applications
Project Contingency	5 – 7%	For MW-scale applications Contingency will vary by size of the application. Vendors are offering 10-year energy services contracts.

Figure 46. Prudent Energy 600-kW/3,600-kWh VRB-ESS Installed at Gills Onions, Oxnard, CA
The system consists of 200-kW modules providing a total of 6 hours of electrochemical energy storage.

Vanadium Redox Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 47, Figure 48, and Figure 49. These estimates are based on capital and O&M data from the Vanadium Redox data sheets in Appendix B. A simple dispatch was assumed: an investor-owned utility financials with 365 cycles per year for 15 years. Generally, key assumptions are IOU ownership, with 365 cycles peak-shaving annually for 15 years. Periodic stack replacement costs are assumed every 8 years and range from $615/kW to $746/kW. See Appendix B for discussion of life-cycle cost methods.

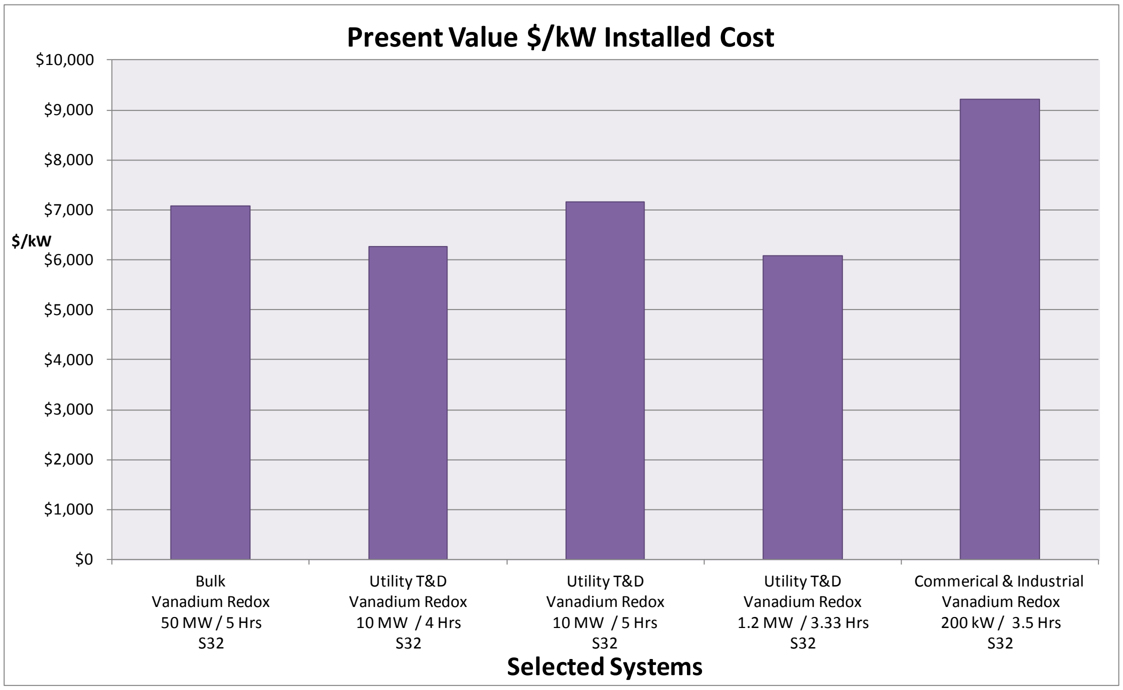

Figure 47. Present Value Installed Cost for Different Vanadium Redox Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

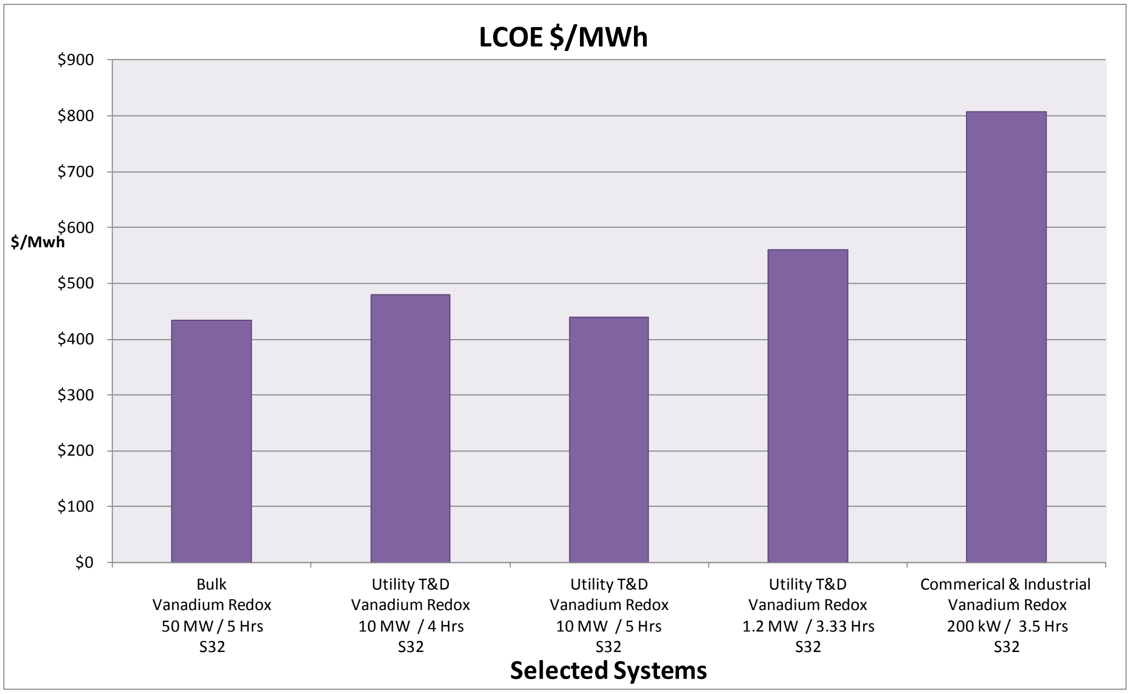

Figure 48. Levelized Cost of Energy in $/MWh for Different Vanadium Redox Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

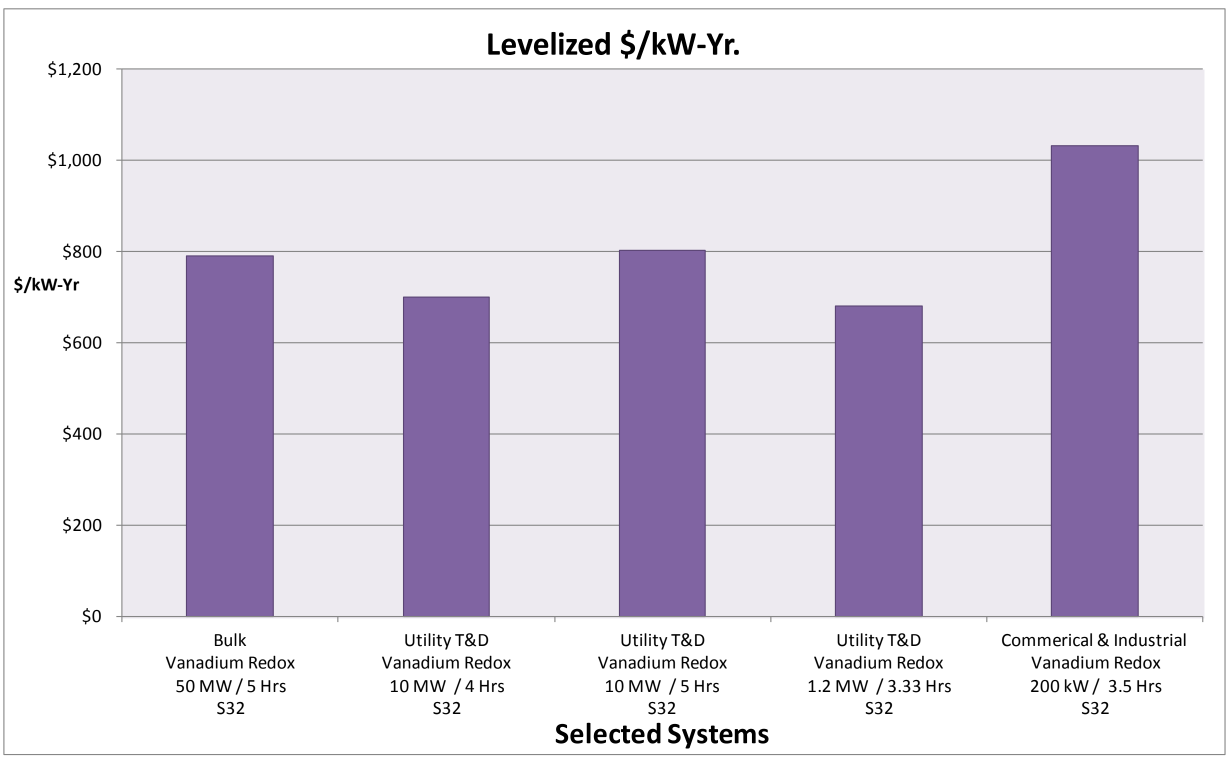

Figure 49. Levelized Cost of Capacity in $/kW-yr for Different Vanadium Redox Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

Additional Vanadium Redox Battery Resources

1. *VRB Energy Storage for Voltage Stabilization: Testing and Evaluation of the PacifiCorp Vanadium Redox Battery Energy Storage System at Castle Valley*, Utah, EPRI ID 1008434, EPRI, Palo Alto, CA, March 2005.

2. *Vanadium Redox Flow Batteries*, EPRI ID 1014836, EPRI, Palo Alto, CA, March 2007.

3. *Assessment of Advanced Batteries for Energy Storage Applications in Deregulated Electric Utilities*, EPRI ID TR-111162, EPRI, Palo Alto, CA, December 1998.

2.8 Iron-chromium Batteries

Technical Description

Iron-chromium (Fe-Cr) redox flow battery systems is another type of flow battery still in the R&D stage but steadily advancing toward early field demonstrations in 2013-2014. The low-cost structure of these systems also makes them worth evaluating for grid-storage solutions. Given the considerable uncertainties in performance and cycle life, process and project contingencies are high. Figure 50 shows the principles of operation for this technology.

Performance Characteristics

Using liquid reactants, only a small volume is electrically active and the cells are hydraulically balanced. Use of dissolved reactants means there is no volume change during cycling. This is in contrast to Li-ion, lead-acid, NaS, Zinc-bromine, and others, which do involve a volume change. This feature results in a less-complex design and simpler controls. The technology may also feature a lower-cost design, materials, and reactants. Figure 51 shows a typical battery Fe-Cr energy storage system concept.

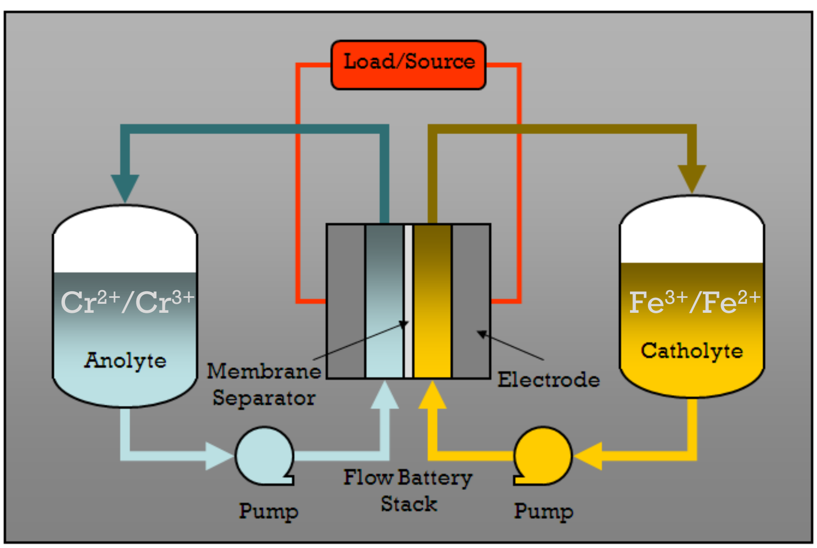

Figure 50. Principles of Operation for an Iron-chromium Battery Energy Storage System

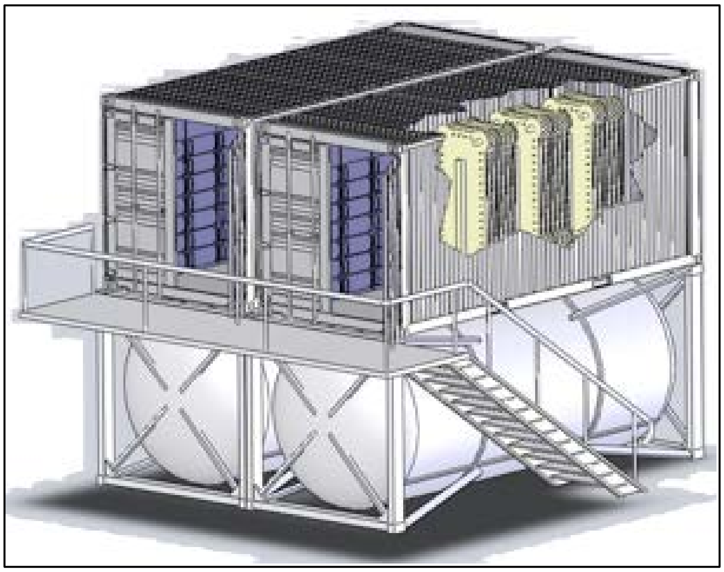

Figure 51. Typical Iron-chromium Battery System
(Photo courtesy EnerVault)

Fe-Cr flow battery systems can be used for time shift on either the utility or customer side of the meter, as well as for frequency regulation services. Figure 52 shows various Fe-Cr system concepts for these applications.

Table 11 is a technology dashboard that shows the status of technology development for Fe-Cr-chromium batteries.

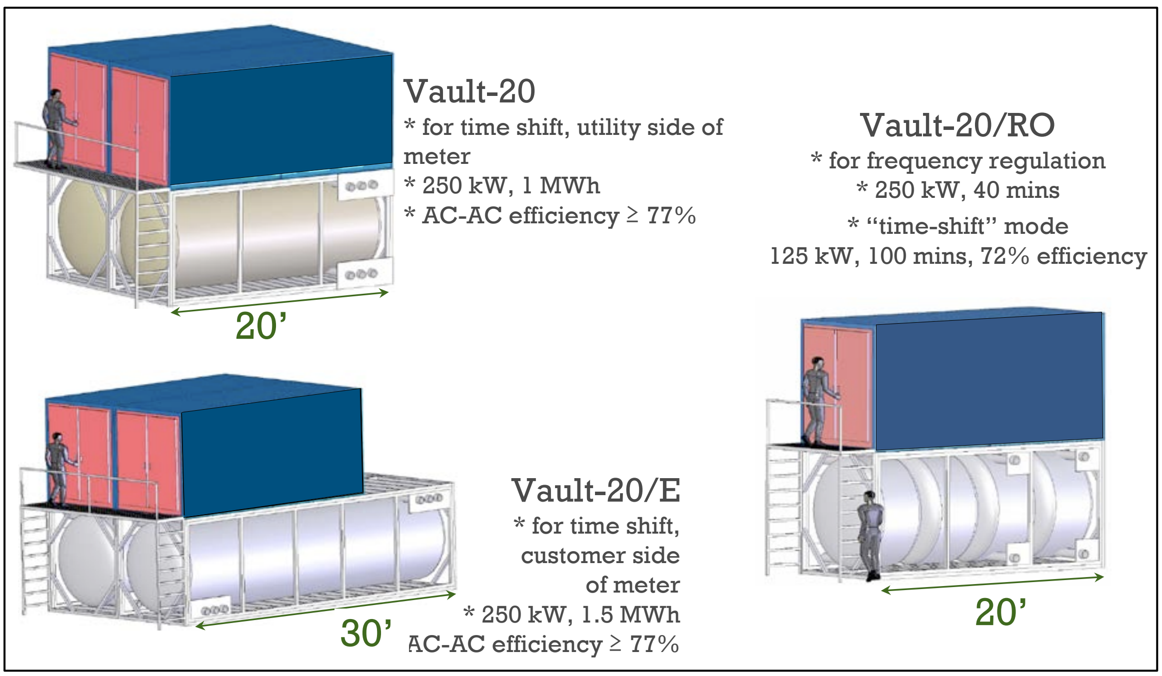

Figure 52. Iron-chromium Battery Storage System Concepts
(Photo courtesy EnerVault)

Table 11. Technology Dashboard: Iron-chromium Battery Systems

Technology Development Status	Laboratory E	Small cells and stack in a lab setting
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	E	-15% to +15%
Operating Field Units	None	None in utility-scale demonstrations Fe-Cr in niche telecom applications
Process Contingency	15 – 20%	Efficiency and cycle-life uncertain. Scale-up uncertainties
Project Contingency	10 – 15%	Limited definition of product designs

Iron-chromium Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 53, Figure 54, and Figure 55. The estimates are based on capital and O&M data from the Fe-Cr data sheets in Appendix B. A simple dispatch was assumed, with investor-owned utility financials and 365 cycles per year for 15 years. Generally, key assumptions are IOU ownership, with 365 cycles peak-shaving annually for 15 years. Periodic stack replacement costs assumed every 8 years and start at $194/kW. See Appendix B for discussion of life-cycle cost methods.

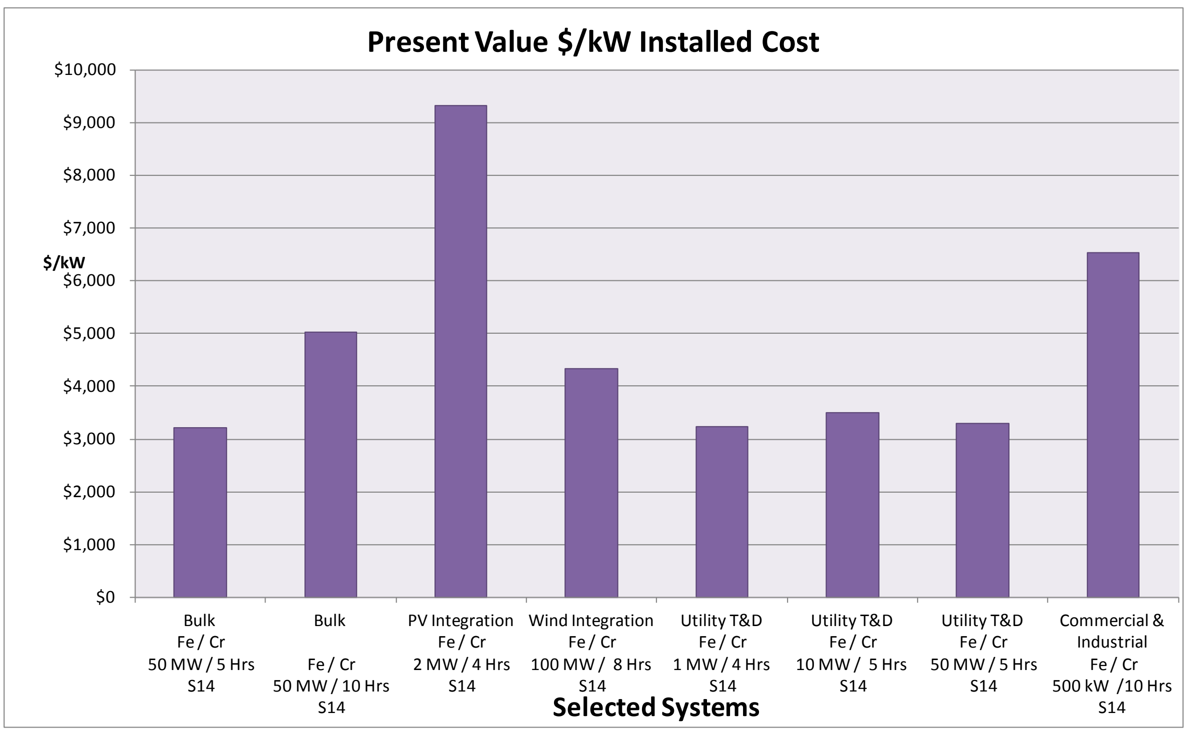

Figure 53. Present Value Installed Cost for Different Iron-chromium Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

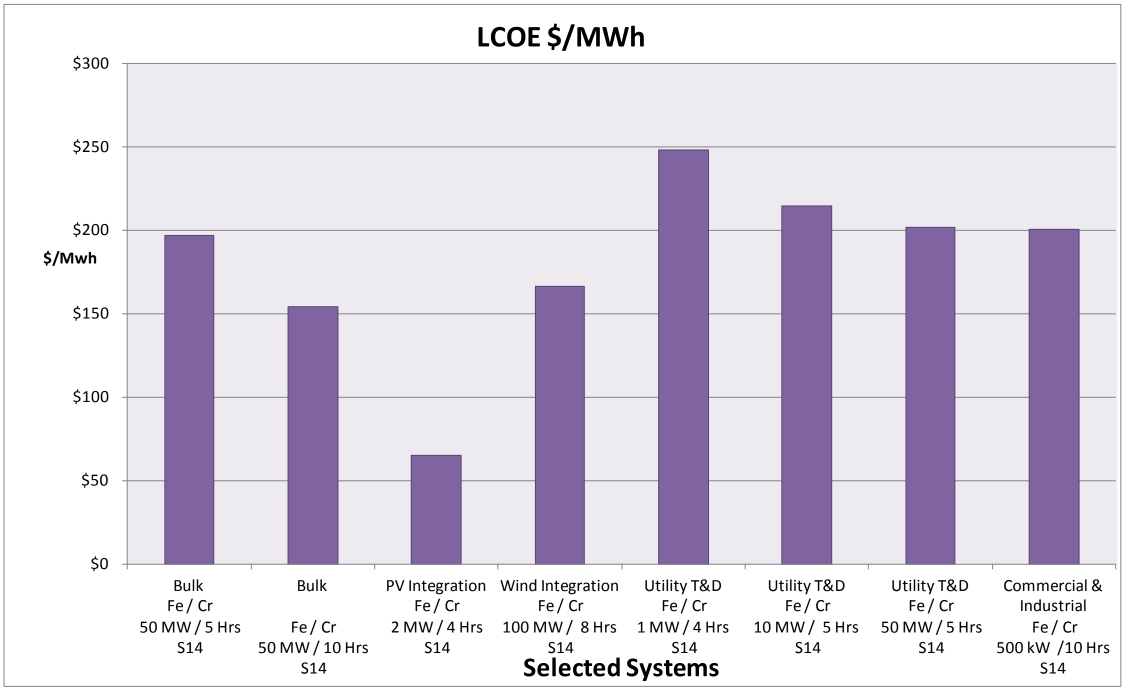

Figure 54. Levelized Cost of Energy in $/MWh for Different Iron-chromium Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

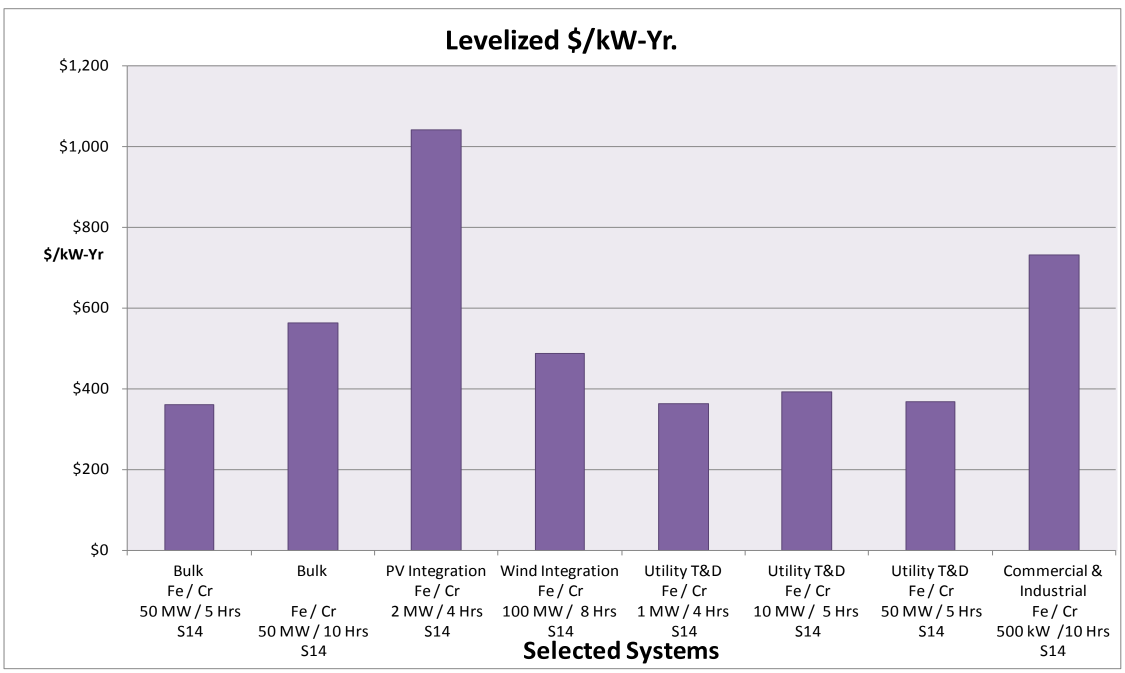

Figure 55. Levelized Cost of Capacity in $/kW-yr for Different Iron-chromium Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

2.9 Zinc-bromine Batteries

Technical Description

The Zinc-bromine battery is another type of flow battery in which the zinc is solid when charged and dissolved when discharged. The bromine is always dissolved in the aqueous electrolyte.

Each cell is composed of two electrode surfaces and two electrolyte flow streams separated by a micro-porous film. The positive electrolyte is called a catholyte; the negative is the anolyte. Both electrolytes are aqueous solutions of zinc bromine ($ZnBr_2$).

During charge, elemental zinc is plated onto the negative electrode. Elemental bromine is formed at the positive electrode. Ideally, this elemental bromine remains only in the positive electrolyte. The micro-porous separator allows zinc ions and bromine ions to migrate to the opposite electrolyte flow stream for charge equalization (see Figure 56 below). At the same time, it inhibits elemental bromine from crossing over from the positive to the negative electrolyte, reducing self-discharge because of direct reaction of bromine with zinc.

The cell electrodes are composed of carbon plastic and are designed to be bipolar. This means that a given electrode serves both as the cathode for one cell and the anode for the next cell in series. Carbon plastic must be used because of the highly corrosive nature of bromine. The positive electrode surface is coated with a high-surface-area carbon to increase surface area. The two electrolytes differ only in the concentration of elemental bromine; both should have the same zinc and bromine ion concentrations at any given time during the charge/discharge cycle. This can best be accomplished through the use of an ion-selective membrane as the separator. This membrane would allow the passage of zinc and bromine ions without allowing the passage of elemental bromine or polybromine. In practice, such membranes have proven more costly and less durable than nonselective membranes. For these reasons, nonselective micro-porous membranes are usually used for the separator. The electrolyte is circulated for a number of reasons. Circulation serves to remove bromine (in the form of polybromine) from the positive electrode quickly, freeing up the surface area for further reaction. It also allows the polybromine to be stored in a separate tank to minimize self-discharge.

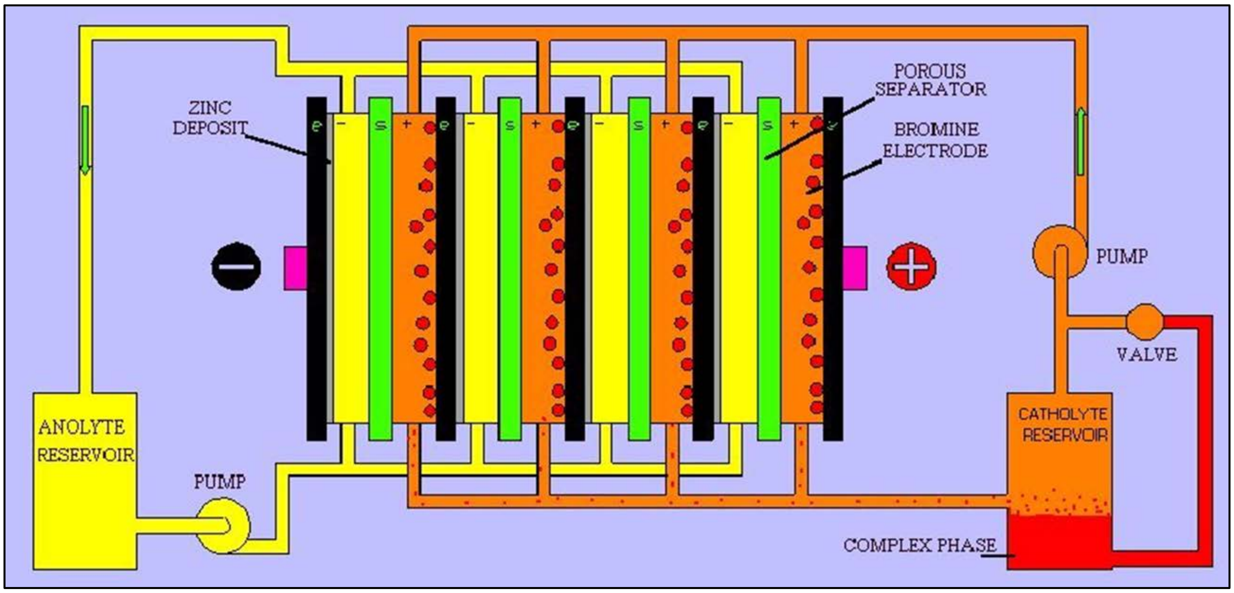

Figure 56. Zinc-bromine Cell Configuration
(Courtesy ZBB Energy Corporation)[36]

On the negative electrode, the flow inhibits the formation of zinc dendrites. Finally, the circulation simplifies thermal management through the use of a heat exchanger. The two electrolytes can flow in the same direction within a cell (co-current), or in opposite directions (counter-current), depending on the design.[37]

Performance Characteristics

Table B-18, Table B-19, and Table B-20 in Appendix B show representative performance characteristics of Zinc-bromine batteries in various storage applications. The most common factor in degradation and potential failure of Zinc-bromine batteries arises from the extremely corrosive nature of the elemental bromine electrolyte. This substance tends to attack all the components of the Zinc-bromine system that are exposed to it. Past failure modes have included damaged seals, corrosion of current collectors, and warped electrodes. The active materials themselves do not degrade. The significance of this fact is that the lifetime is not strongly dependent on the number of cycles or the depth of discharge, but on the number of hours that the system has been operational. During normal operation, Zinc-bromine batteries do not present unusual environmental hazards. They do, however, contain materials that can become environmental contaminants. Bromine is a toxic material and should be recovered in the event of a spill or when the unit is decommissioned. Zinc-bromine is a corrosive and should be handled

[36] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation.
[37] Ibid.

appropriately. Zinc is considered a transition-metal contaminant in some locales and thus should be properly recovered when the unit is decommissioned.[38]

Maturity and Commercial Availability

Zinc-bromine batteries are in an early stage of field deployment and demonstration trials. While field experience is currently limited, vendors claim estimated lifetimes of 20 years, long cycle lives, and operational ac-to-ac efficiencies of approximately 65%. Module sizes vary by manufacturer but can range from 5 kW to 1000 kW, with variable energy storage duration from two to six hours, depending on the service requirements and need. Small projects comprising 5-kW/2-hour systems are being deployed in rural Australia as an alternative to installing new power lines. In the United States, electric utilities plan to conduct early trials of 0.5 – 1.0 MW systems for grid support and reliability by 2014.

Table 12 is a technology dashboard that shows the status of technology development for Zinc-bromine systems.

Table 12. Technology Dashboard: Zinc-bromine Flow-type Battery Systems

Technology Development Status	Demonstration trials	Small systems deployed in limited field demonstrations.
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	C	-10% to +15%
Operating Field Units	3 or more	None in utility-scale demonstrations of 500 kW or larger.
Process Contingency	10%	Efficiency uncertain. Limited life and operating experience at greater than 100 kW.
Project Contingency	10 – 15%	Transportable and small systems have lower construction and installation issues.

Figure 57 shows a containerized Zinc-bromine system made by RedFlow.

[38] Ibid.

Figure 57. A 90-kW/180-kWh Zinc-bromine Energy Storage System by RedFlow
(Housed in a 20-foot shipping container.)

Zinc-bromine Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 58, Figure 59, Figure 60, Figure 61, Figure 62, and Figure 63 for each application. The estimates are based on capital, O&M data and stack replacement costs as shown in the data sheets for Zinc-bromine in Appendix B. A simple dispatch was assumed; generally, key assumptions are IOU ownership, with 365 cycles peak-shaving annually for 15 years. See Appendix B for discussion of life-cycle cost methods.

Additional Zinc-bromine Battery References

1. *Validated Test Data on MWh-Scale Flow and Other Battery Systems: Large Battery Installations 2003*, EPRI ID 1005019, EPRI, Palo Alto, CA, December 2003.

2. *Electricity Energy Storage Technology Options*, EPRI ID 1020676, EPRI, Palo Alto, CA, December 2010.

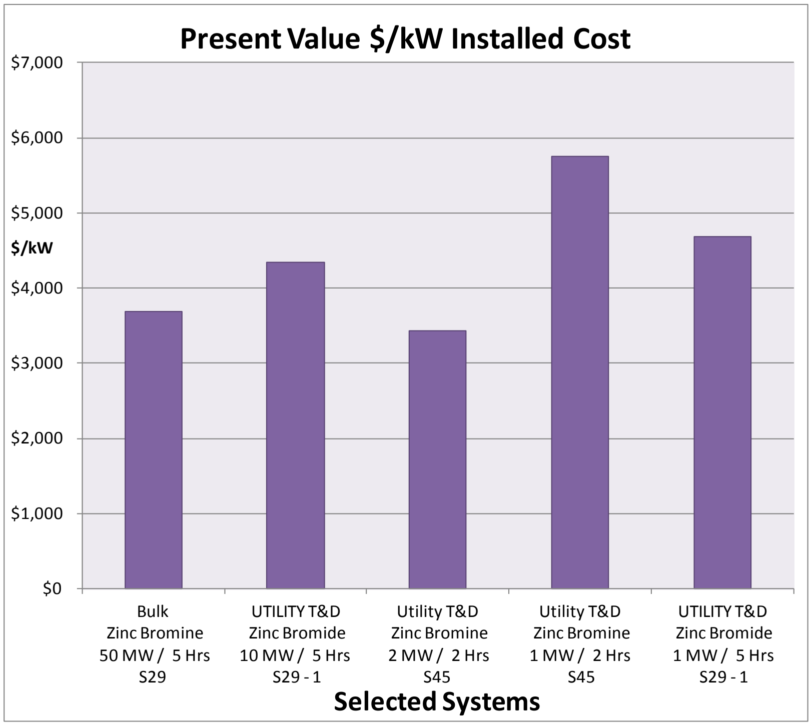

Figure 58. Present Value Installed Cost for Zinc-bromine Systems in Bulk and Utility Transmission and Distribution Service
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

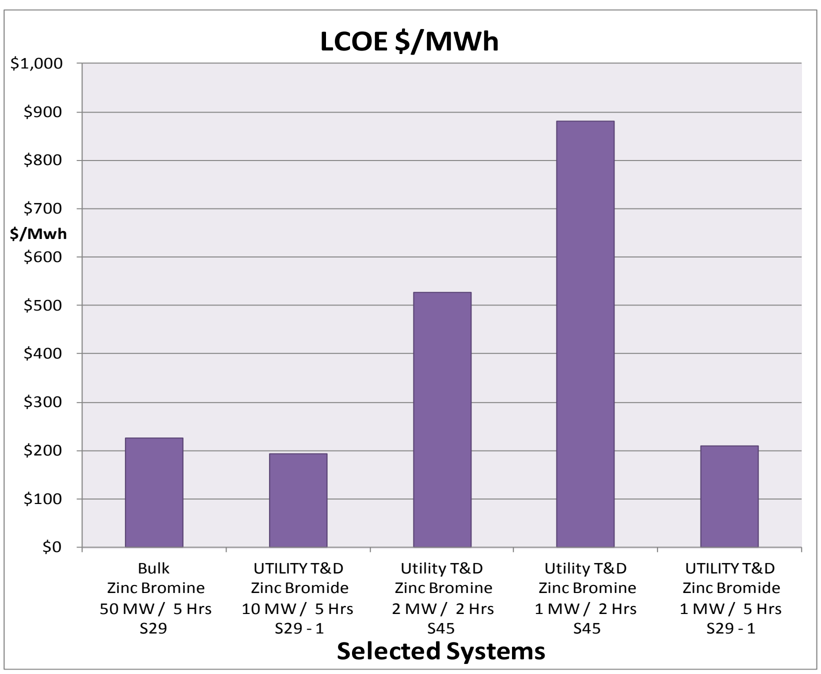

Figure 59. Levelized Cost of Energy in $/MWh for Zinc-bromine Systems in Bulk and Utility Transmission and Distribution Service
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

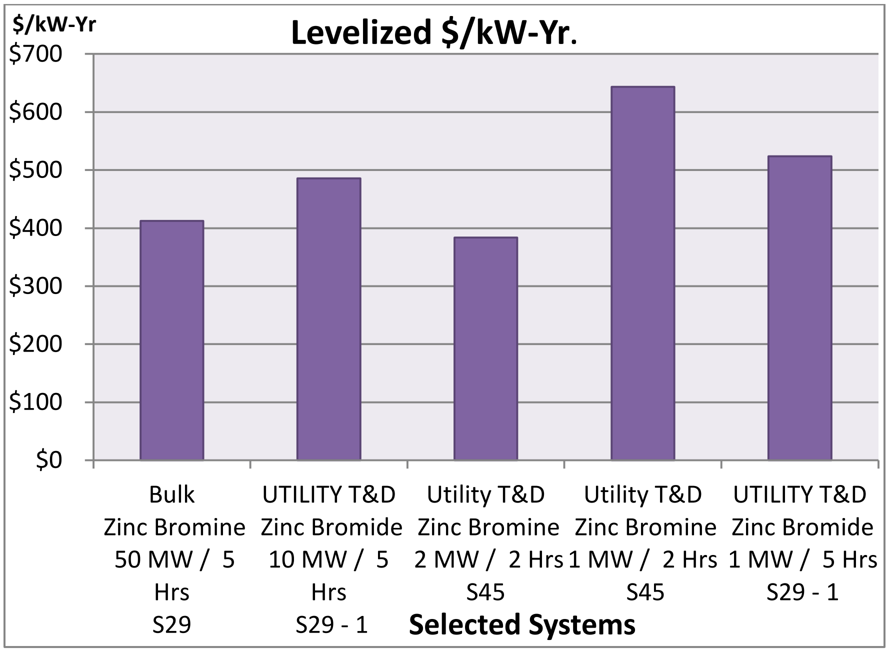

Figure 60. Levelized Cost of Capacity in $/kW-yr for Zinc-bromine Systems in Bulk and Utility Transmission and Distribution Service
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

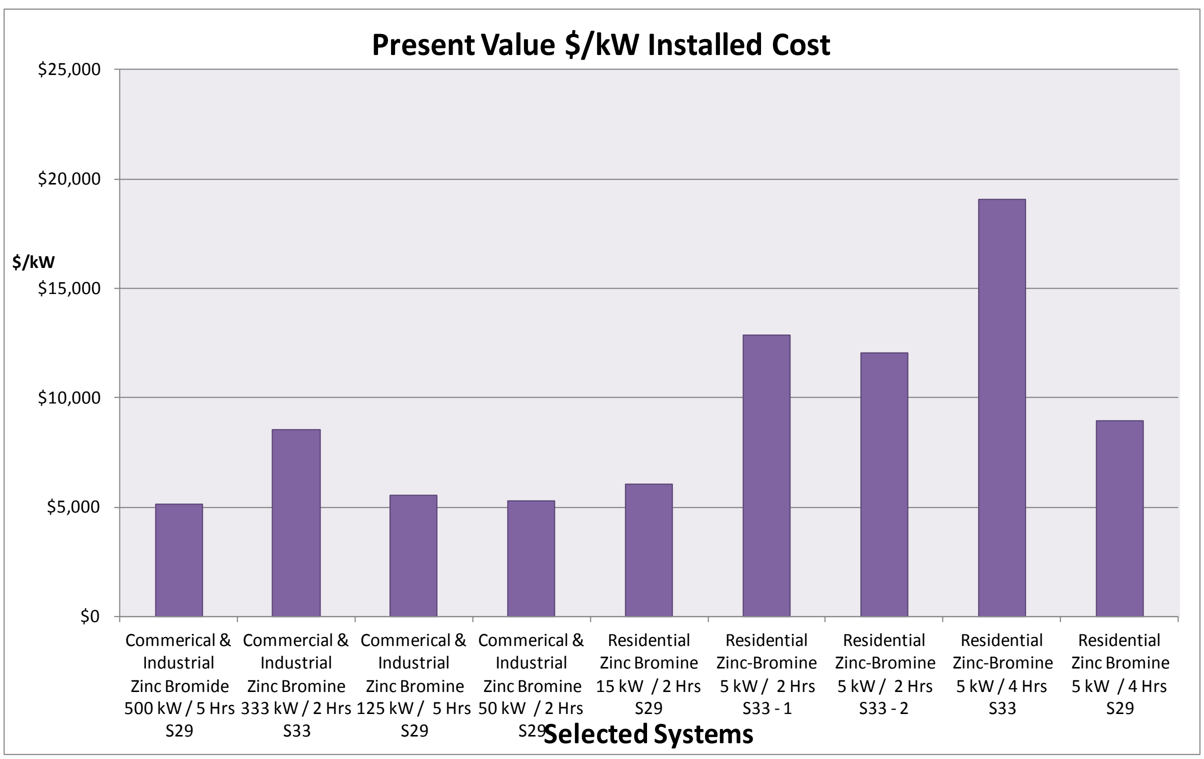

Figure 61. Present Value Installed Cost for Zinc-bromine Systems in Commercial and Industrial and Residential Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

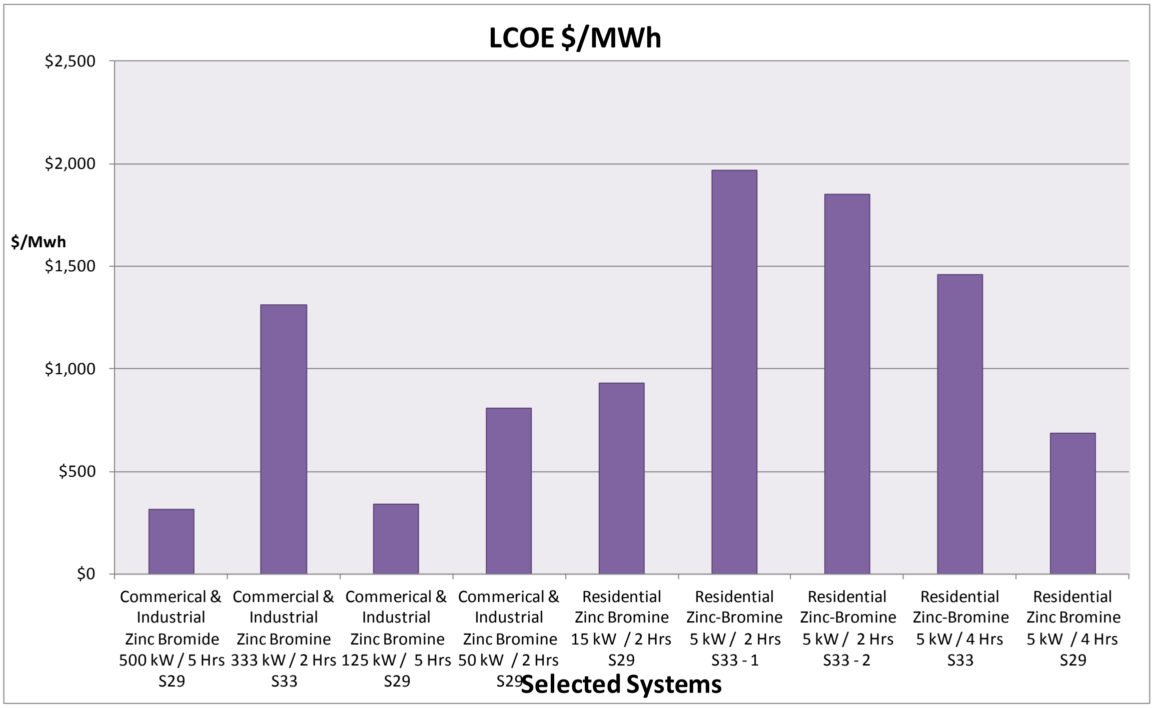

Figure 62. Levelized Cost of Energy in $/MWh for Zinc-bromine Systems in Commercial and Industrial and Residential Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

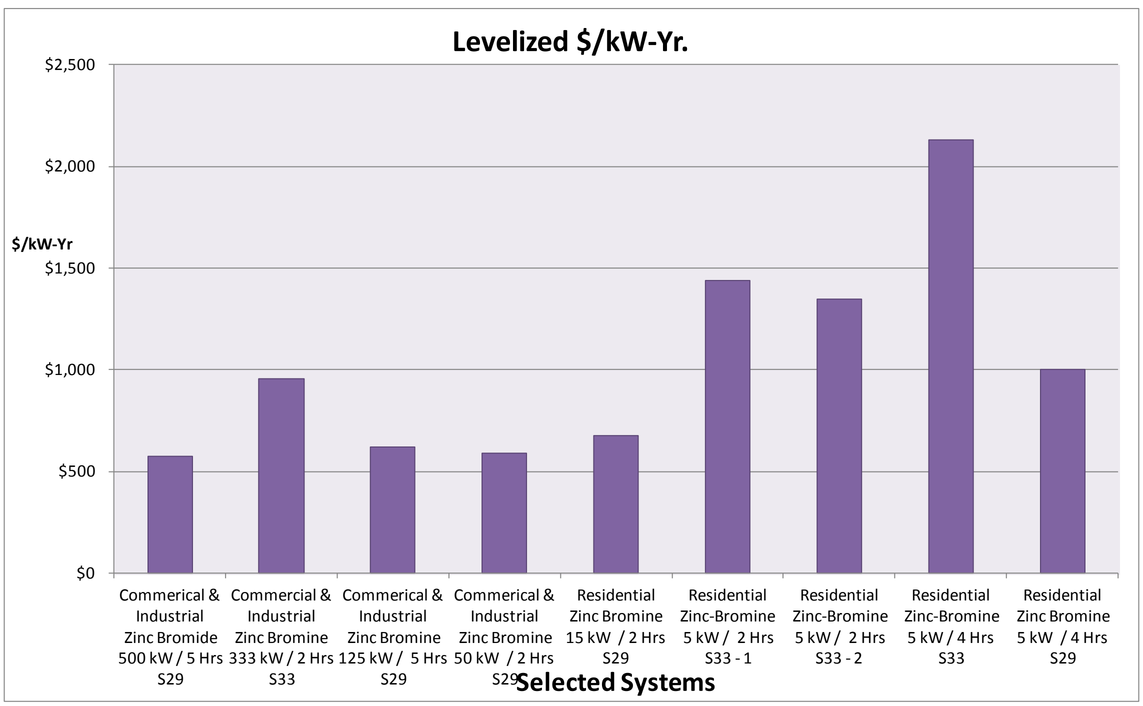

Figure 63. Levelized Cost of Capacity in $/kW-yr for Zinc-bromine Systems in Commercial and Industrial and Residential Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

2.10 Zinc-air Batteries

Technical Description

Zinc-air batteries are a metal-air electrochemical cell technology. Metal-air batteries use an electropositive metal, such as zinc, aluminum, magnesium, or lithium, in an electrochemical couple with oxygen from the air to generate electricity. Because such batteries only require one electrode within the product, they can potentially have very high energy densities. In addition, the metals used or proposed in most metal-air designs are relatively low cost. This has made metal-air batteries potentially attractive for electric vehicle (EV) and power electronics applications in the past, as well as raising hopes for a low-cost stationary storage system for grid services. Zinc-air batteries take oxygen from the surrounding air to generate electric current. The oxygen serves as an electrode, while the battery construction includes an electrolyte and a zinc electrode that channels air inside the battery as shown in Figure 64.

The Zinc-air battery produces current when the air electrode is discharged with the help of catalysts that produce hydroxyl ions in the liquid electrolyte. The zinc electrode is then oxidized and releases electrons to form an electric current. When the battery is recharged, the process is reversed, and oxygen is released into the air electrode.

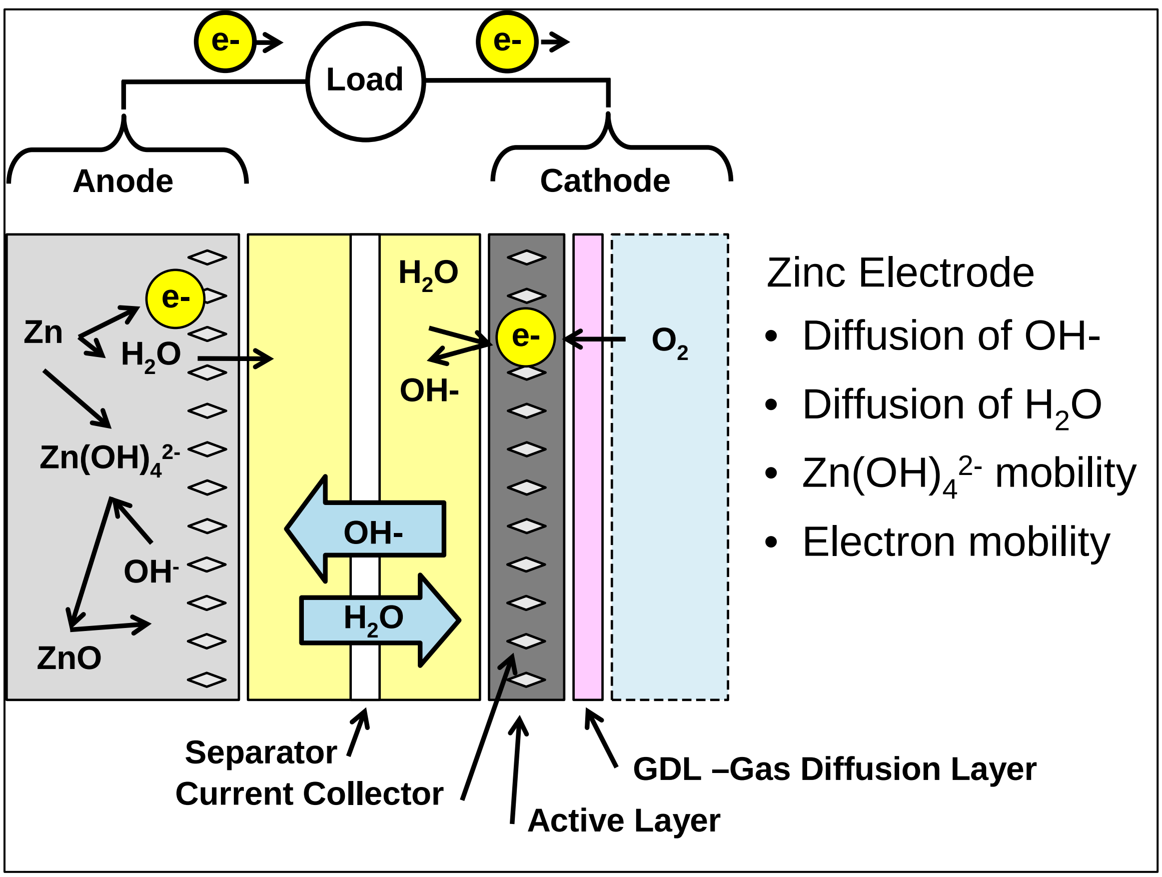

Figure 64. Zinc-air Battery Functional Schematic
(Courtesy ReVolt)

The challenge for researchers has been to address issues such as electrolyte management, avoiding carbon dioxide (CO_2) impacts from the air on the electrolyte and cathode, thermal management, and avoiding Zn dentrite formation. Methods are also being investigated to address issues with the air electrolyte not deactivating in the recharging cycle and slowing or stopping the oxidation reaction. The cessation of the oxidation reaction reduces the number of times that a Zinc-air battery can be recharged.

Despite the many advantages, metal-air batteries also pose several historical disadvantages. The batteries are susceptible to changes in ambient air conditions, including humidity and airborne contaminants. The air electrode – a sophisticated technology that requires a three-way catalytic interface between the gaseous oxygen, the liquid electrolyte, and the solid current collector – has been difficult and expensive to make. However, the technology is far more stable and less dangerous than other battery technologies.

Performance Characteristics

Electric recharge has been difficult and inefficient with metal-air batteries, with typical round-trip efficiencies below 50 percent. Some developers have attempted to overcome this limitation with mechanically rechargeable systems in which the discharged metal anode is replaced with a fresh metal anode and the system continues to operate.

There are currently a few early-stage companies attempting to bring energy-dense, high-operating-efficiency, better depth-of-discharge stationary systems to the market, particularly for utility T&D grid support and renewable energy integration. R&D is underway by several companies, with some research still in the university laboratory stage.

Zinc-air batteries have up to three times the energy density of Li-ion, its most competitive battery technology. Unlike lithium-ion, however, Zinc-air batteries neither produce potentially toxic or explosive gases, nor contain toxic or environmentally dangerous components. Zinc-oxide, which is the main material in a zinc-air battery, is 100-percent recyclable.

Maturity and Commercial Availability

Zinc-air technology is still in early R&D phase for stationary storage systems for grid services markets. Despite substantial technical obstacles faced in the past, this technology holds a great deal of potential because of its low capital cost for grid support and potentially for electric transportation applications.

Table 13 illustrates the technology dashboard for Zinc-air energy storage systems.

Table 13. Technology Dashboard: Zinc-air Battery Systems

Technology Development Status	Laboratory E	Small cells and stacks in a lab setting some bench scale system tests
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	E	-15% to +15%
Operating Field Units	None	None in utility-scale demonstrations
Process Contingency	15 – 20%	Efficiency and cycle life uncertain. Scale-up uncertainties
Project Contingency	10 – 15%	Limited definition of product designs.

Figure 65 and Figure 66 show a 1-kW battery prototype and an artist's rendering of a 1-MW/6 MWh system.

Figure 65. 1-kW Zinc-air Prototype
(Photo courtesy of EOS Energy Storage)

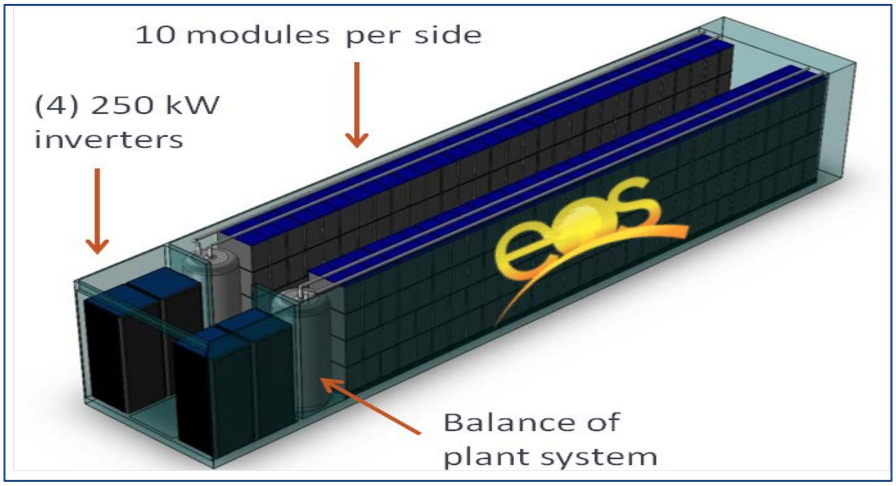

Figure 66. Illustration of 1-MW/6/MWh Eos Aurora Zinc-air Design
(Developed by EOS Energy Storage)

Zinc-air Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 67, Figure 68, and Figure 69 by application. The estimates are based on capital, O&M data, and stack replacement costs from the Zinc-air data sheets in Appendix B. A simple dispatch was assumed, with life-cycle estimates based on IOU financial assumptions of 365 cycles annually for 15 years. There was no periodic stack replacement costs assumed in these figures. See Appendix B for discussion of life-cycle cost methods. If a replacement cost of $200 per kW every 5 years is assumed, the impact on present value installed cost is about a 9% increase.

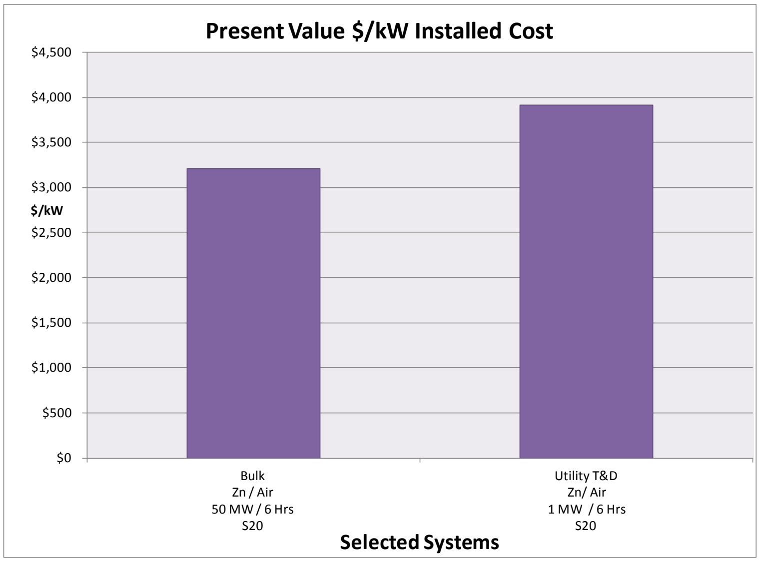

Figure 67. Present Value Installed Cost for Zinc-air Systems in Bulk Services
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

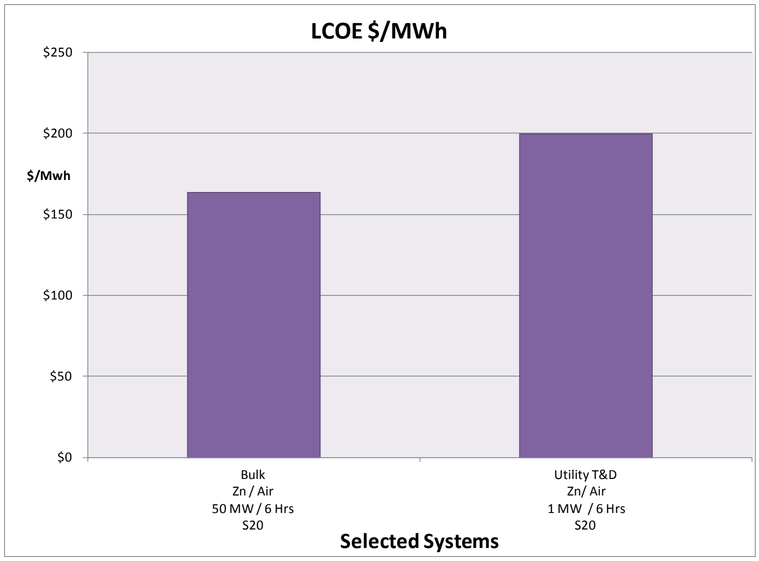

Figure 68. Levelized Cost of Energy in $/MWh for Zinc-air Systems in Bulk Services
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

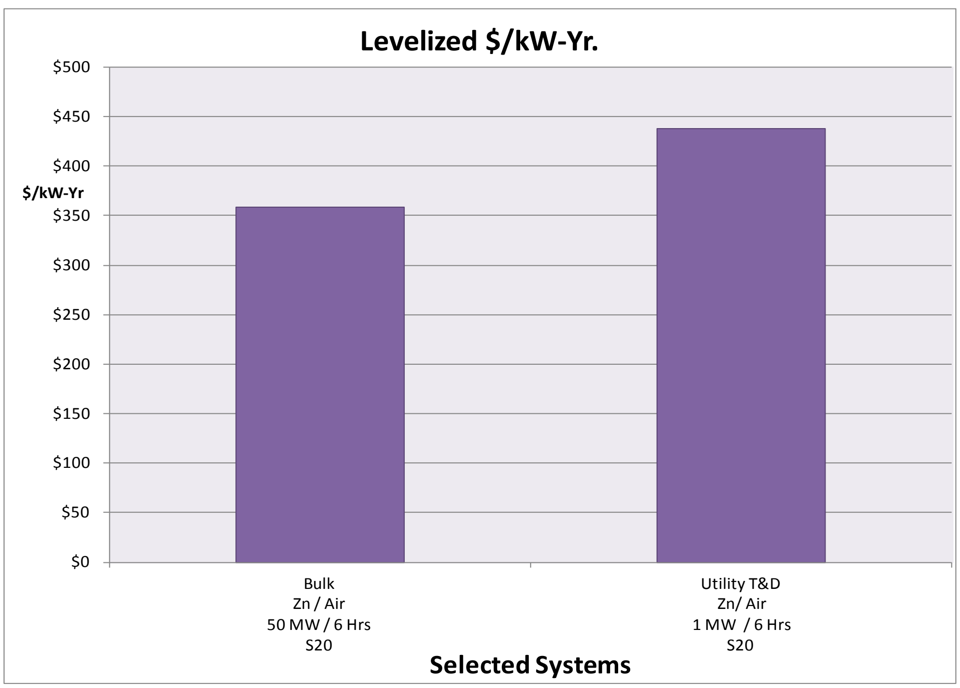

Figure 69. Levelized Cost of Capacity in $/kW-yr for Zinc-air Systems in Bulk Services
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

2.11 Lead-acid Batteries

Technical Description

Lead-acid batteries are the oldest form of rechargeable battery technology. Originally invented in the mid-1800s, they are widely used to power engine starters in cars, boats, planes, etc. All lead-acid designs share the same basic chemistry. The positive electrode is composed of lead-dioxide, PbO_2, while the negative electrode is composed of metallic lead, Pb. The active material in both electrodes is highly porous to maximize surface area. The electrolyte is a sulfuric acid solution, usually around 37% sulfuric acid by weight when the battery is fully charged.

Lead-acid energy storage technologies are divided into two types: lead-acid carbon technologies and advanced lead-acid technologies. Lead-acid carbon technologies use a fundamentally different approach to lead-acid batteries through the inclusion of carbon, in one form or another, both to improve the power characteristics of the battery and to mitigate the effects of partial states of charge. Certain advanced lead-acid batteries are conventional valve-regulated lead-acid (VRLA) batteries with technologies that address the shortcomings of previous lead-acid products through incremental changes in the technology.[39] Other advanced lead-acid battery systems incorporate solid electrolyte-electrode configurations, while others incorporate capacitor technology as part of anode electrode design.

Lead-acid Carbon

Lead-acid carbon technology can exhibit a high-rate characteristic in both charge and discharge with no apparent detrimental effects as are typically experienced in traditional vented lead-acid (VLA) and VRLA batteries. This characteristic allows the lead-acid carbon batteries to deliver and accept high current rates only available with current higher-cost nickel metal-hydride (Ni-MH) and Li-ion batteries.[40]

There are three major lead-acid carbon technologies currently moving into the market. The three developers working on these technologies are Ecoult/EastPenn, Axion Power International, and Xtreme Power. Each developer has a different implementation of carbon integrated with the traditional lead-acid battery negative plate. In general, each variation is targeting a specific niche market.[41]

According to Axion, their proprietary PbC® technology is a multi-celled asymmetrically supercapacitive lead-acid-carbon hybrid battery. The negative electrodes are five-layer assemblies that consist of a carbon electrode, a corrosion barrier, a current collector, a second corrosion barrier, and a second carbon electrode. These electrode assemblies are then combined with conventional separators and positive electrodes. The resulting battery is filled with an acid

[39] *Energy Storage and Distributed Generation Technology Assessment: Assessment of Lead-Acid-Carbon, Advanced Lead-Acid, and Zinc-Air Batteries for Stationary Application*, EPRI, EPRI ID 1017811, EPRI, Palo Alto, CA, December 2009.
[40] Ibid.
[41] Ibid.

electrolyte, sealed, and connected in series to other cells. Laboratory prototypes have undergone deep-discharge testing and withstood more than 1600 cycles before failure. In comparison, most lead-acid batteries designed for deep discharges deliver 300 to 500 cycles. Application-specific prototypes may offer several performance advantages over conventional lead-acid batteries, including:

- Significantly faster recharge rates,
- Significantly longer cycle lives in deep discharge applications, and
- Minimal required maintenance.[42]

Xtreme Power systems are finding early uses in wind and PV smoothing applications. The Xtreme Power PowerCell™ is a 12-volt, 1-kWh, advanced dry cell battery utilizing a solid-state battery design and chemistry. The uniform characteristics of the PowerCells™ allow thousands to be assembled in massive parallel and series matrices, suited for use in large-scale utility applications requiring many megawatts of power while still maintaining a manageable footprint. Its low internal resistance results in high-power retention, as well as the ability to rapidly charge and discharge large amounts of power[43] (see Appendix B). The vendor reports a PowerCell™'s life is based on its depth of discharge (DOD). Cycle life is a log function of DOD and ranges from over 500,000 cycles at 1% DOD to 1,000 cycles at 100% DOD.

Advanced Lead-acid Technologies

While developers of lead-acid carbon technologies are improving the capability of conventional lead-acid technologies through incorporation of carbon in one or both electrodes, manufacturers such as GS Yuasa and Hitachi are taking other approaches. Advanced lead-acid products from these manufacturers focus on technology enhancements such as carbon-doped cathodes, granular silica electrolyte retention systems (GS Yuasa), high-density positive active material, and silica-based electrolytes (Hitachi).

Some advanced lead batteries have supercapacitor-like features that give them fast response, similar to flywheels or Li-ion batteries. Advanced lead-acid systems from a number of companies are currently in early field trial demonstrations (see Appendix G).

Performance Characteristics

Traditional VLA and VRLA batteries are typically designed for optimal performance in either a power application or an energy application, but not both. That is, a battery specifically designed for power applications can indeed deliver reasonable amounts of energy (e.g., for operating car lights), but it is not designed to deliver substantial amounts of energy (e.g., 80-percent deep discharges) on a regular basis. In comparison, a lead-acid carbon or advanced lead-acid battery

[42] Axion website: http://www.axionpower.com/profiles/investor/fullpage.asp?f=1&BzID=1933&to=cp&Nav=0&LangID=1&s=0&ID=10298, accessed March 15, 2013
[43] Xtreme Power website: www.xtremepower.com, accessed March 15, 2013.

specifically designed for energy applications can deliver high impulses of power if needed, although it is not specifically designed to do so.

There are several lead-acid carbon and advanced lead-acid technologies; the values are an average of currently available systems. Each system will have its own performance characteristics.[44]

Disposal of lead-acid batteries is an important part of the life cycle. The environmental and safety hazards associated with lead require a number of regulations concerning the handling and disposal of lead-acid batteries. Lead-acid batteries are among the most recycled products in the world. Old batteries are accepted by lead-acid manufacturers for recycling. Batteries are separated into their component parts. The lead plates and grids are smelted to purify the lead for use in new batteries. Acid electrolyte is neutralized, scrubbed to remove dissolved lead, and released into the environment. Other component parts such as plastic and metal casings are also recycled.[45]

Maturity and Commercial Availability

Lead-acid batteries are the most commercially mature rechargeable battery technology in the world. VRLA batteries are used in a variety of applications, including automotive, marine, telecommunications, and uninterruptible power supply (UPS) systems. However, there have been very few utility T&D applications for such batteries due to their relatively heavy weight, large bulk, cycle-life limitations, and perceived reliability issues (stemming from maintenance requirements).

As shown in Figure 70, a 1-MW/1.5-MWh lead-acid battery by GNB Industrial Power (now Exide) has been operating for 12 years in Metlakatla, AK. In this project, the battery system exhibited very little visible degradation upon post-test analysis and was replaced in 2008, after 12 years of continuous shallow discharge service. Other lead-acid carbon energy systems have been deployed in sizes of 10 to 20 MW.[46]

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[44] *Energy Storage Market Opportunities: Application Value Analysis and Technology Gap Assessment*, EPRI ID 1017813, EPRI, Palo Alto, CA, December 2009.

[45] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Application*, EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003.

[46] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits*, PI: Dan Rastler, EPRI ID 1020676, EPRI, Palo Alto, CA, September 2010.

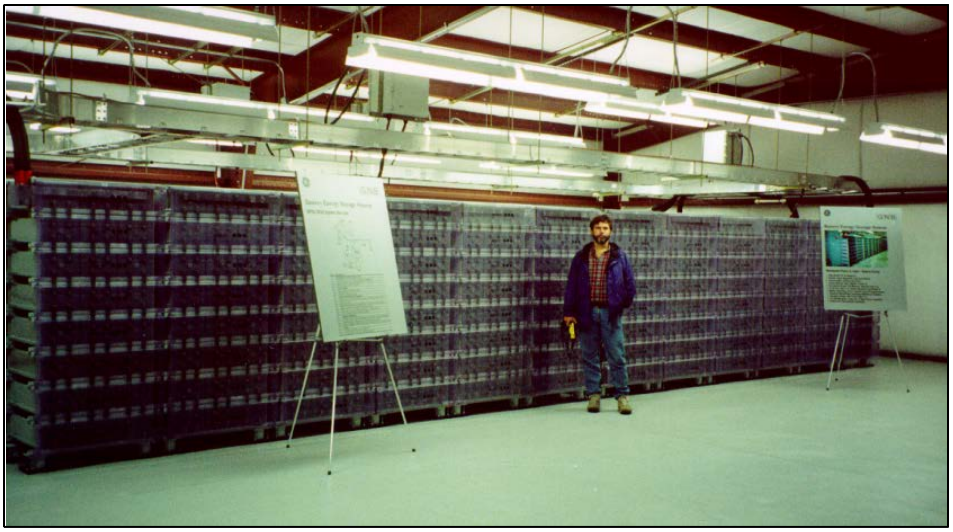

Figure 70. 1-MW/1.5-MWh Lead-acid Carbon System at Metlakatla, AK[47]

Many traditional suppliers and new entrants are seeking to introduce advanced lead-acid technology in U.S. utility markets through products designed for residential, commercial, and industrial use. While each of these cannot be covered in detail in this Handbook, the reader must clearly define the application use case, requirements, and life-cycle expectations during the process of review, assessment, and final selection. Some of the more notable recent field deployments are reviewed here.

Hitachi is developing their advanced lead-acid product for renewable integration and smart grid projects in Japan, with the intent of competing with NaS and Li-ion batteries. Some of their advanced lead-acid batteries have been integrated with wind-generation sites, including the well-known project at Tappi Wind Park installed in 2001 with support from the New Energy Development Organization (NEDO), a Japanese government organization that promotes the development of new energy technologies. The Tappi Wind Park battery system, shown in Figure 71 used an earlier generation of the Hitachi advanced lead-acid battery technology. In August 2009, Hitachi completed a 10.4-MWh battery, built to stabilize a 15-MW wind facility at Goshogawara in northern Japan. A similar plant was installed in late 2010 at another wind-generation site at Yuasa. This battery is now available to companies for integration into the United States, although costing for the United States is unclear at this time.[48]

[47] *Energy Storage and Distributed Generation Technology Assessment: Assessment of Lead-Acid-Carbon, Advanced Lead-Acid, and Zinc-Air Batteries for Stationary Application*, EPRI ID 1017811, EPRI, Palo Alto, CA, 2009.
[48] Ibid.

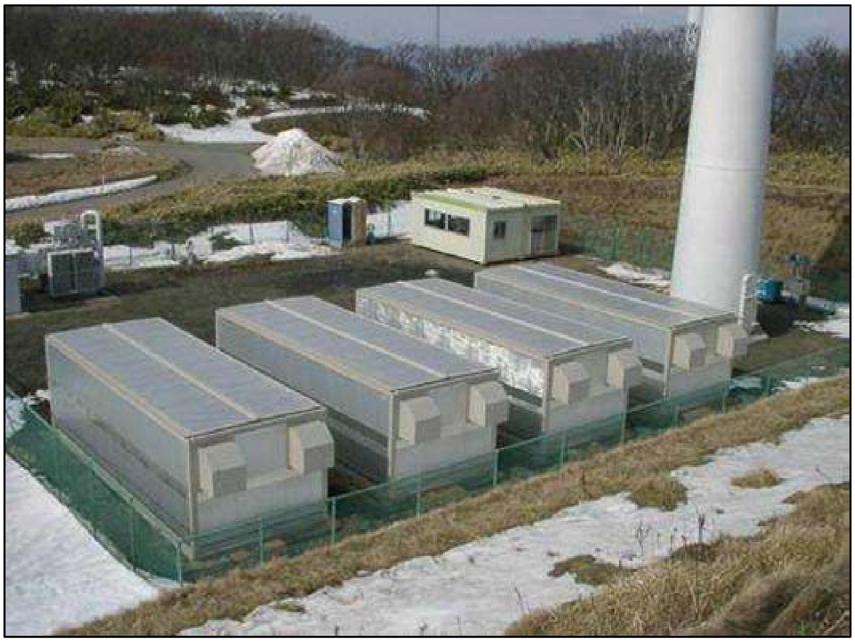

Figure 71. Acid Battery Installation at Tappi Wind Park
(Courtesy Hitachi)[49]

Xtreme Power, Inc., has deployed its advanced lead-acid XP System in multiple services, including wind and PV integration, transmission and distribution applications, and smart grid applications in Hawaii. One of these systems deployed in Maui, HI, is shown in Figure 72. Xtreme Power also plans to offer grid congestion and large-scale power management products for grid-tied services.

Figure 73 shows another advanced lead-acid system made by Ecoult/East Penn installed at a Public Service Company of New Mexico (PNM) project site.

[49] Ibid.

Figure 72. 1.5-MW/1-MWh Advanced Lead-acid Dry Cell Systems by Xtreme Power in a Maui Wind Farm
(Source: Xtreme Power)

Figure 73. 500-kW/1-MWh Advanced Lead-acid Battery for Time-shifting and 900-kWh Advanced Carbon Valve-regulated Battery for Photovoltaic Smoothing
This is a solar energy storage facility that is fully integrated into a utility's power grid.
(Source: PNM Resources)

Table 14 is a technology dashboard that shows the status of technology development for lead-acid batteries.

Table 14. Technology Dashboard: Advanced Lead-acid Battery Systems

Technology Development Status	Demonstration C	Limited field demonstrations Some advanced systems can be classified as commercial
Confidence of Cost Estimate	D	Vendor quotes and system installation estimates
Accuracy Range	C	-10% to +15%
Operating Field Units	5 or more	Several wind and photovoltaic applications expected by 2013
Process Contingency	10 – 15%	Limited testing and field experience
Project Contingency	5 – 10%	Cycle life and depth of discharge for application needs careful evaluation; limited operation and maintenance cost data.

Lead-acid Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 74 through Figure 88 for each application. The estimates are based on capital, O&M data, and battery replacement costs from the Lead-acid data sheets in Appendix B. Life-cycle estimates were based on IOU financial assumptions, with 365 cycles annually for 15 years. For the frequency regulation application, a simple dispatch was assumed based on each system operating 5000 cycles per year. See Appendix B for discussion of life-cycle cost methods for this application.

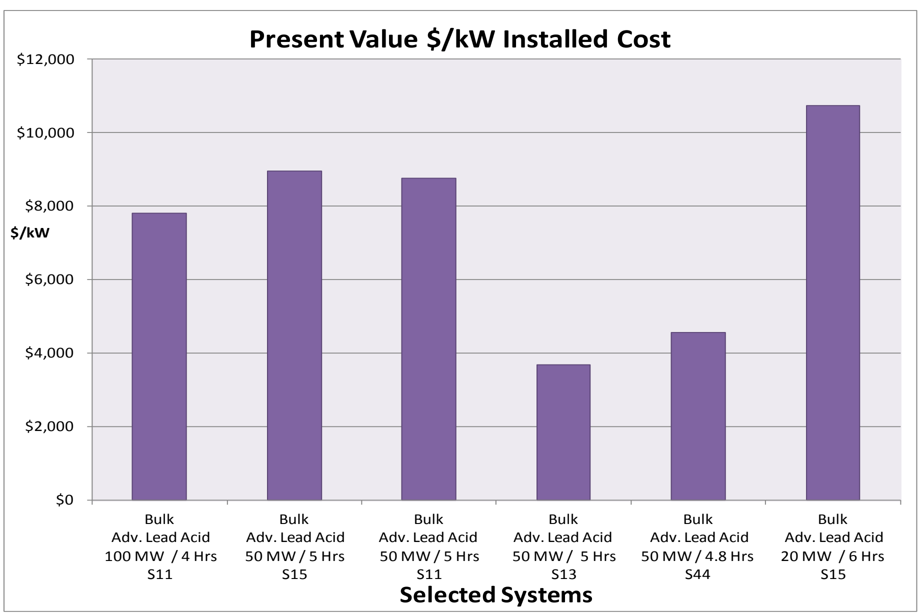

Figure 74. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems Bulk Service Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

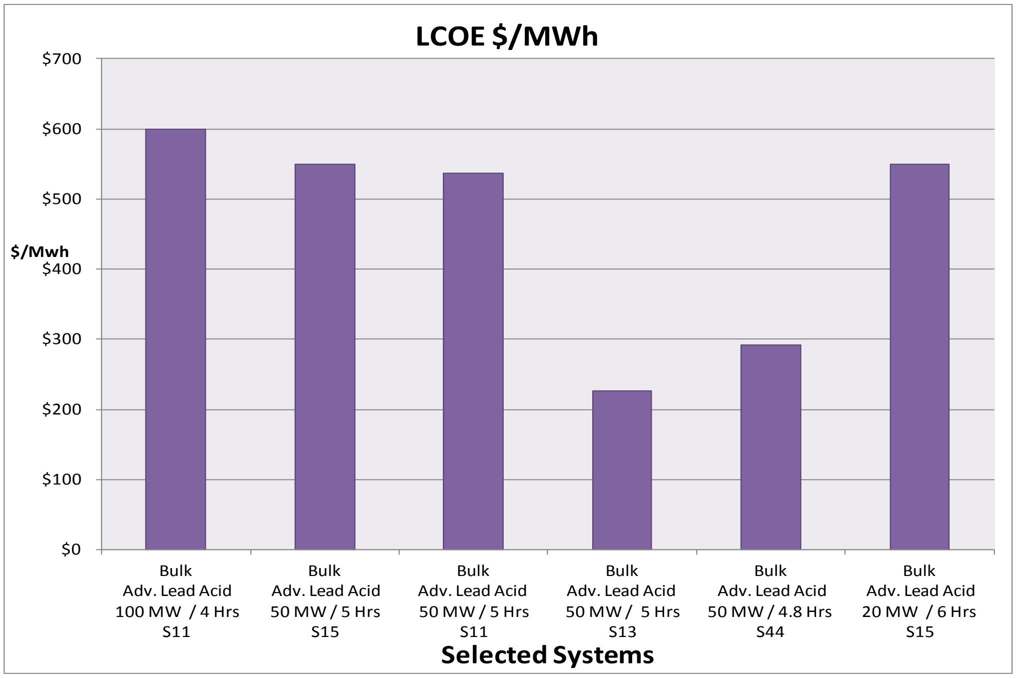

Figure 75. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Bulk Service Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

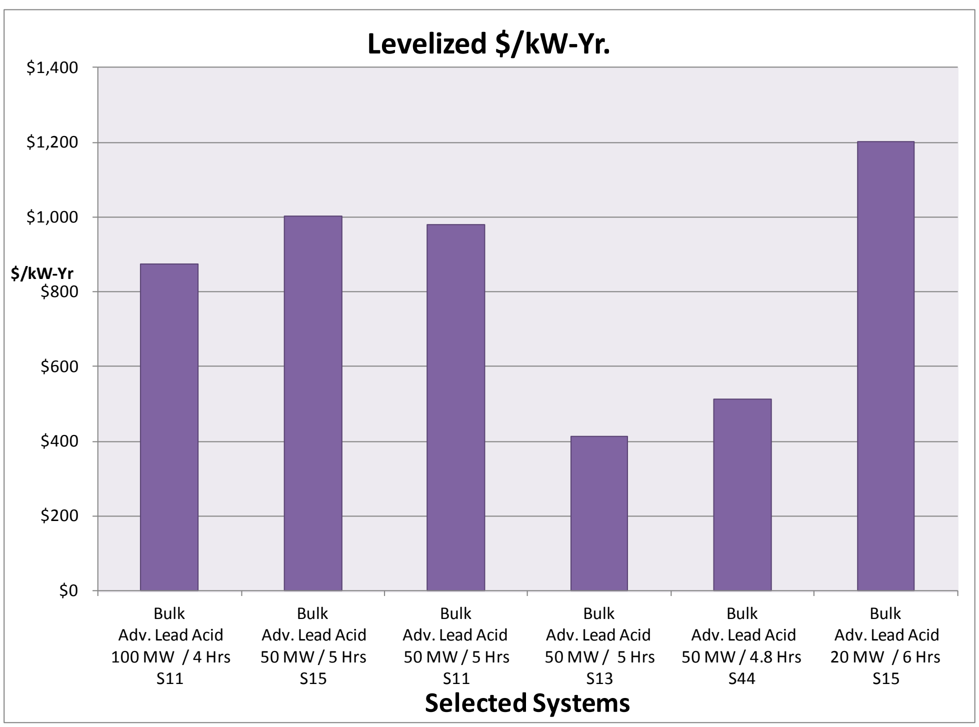

Figure 76. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Bulk Service Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

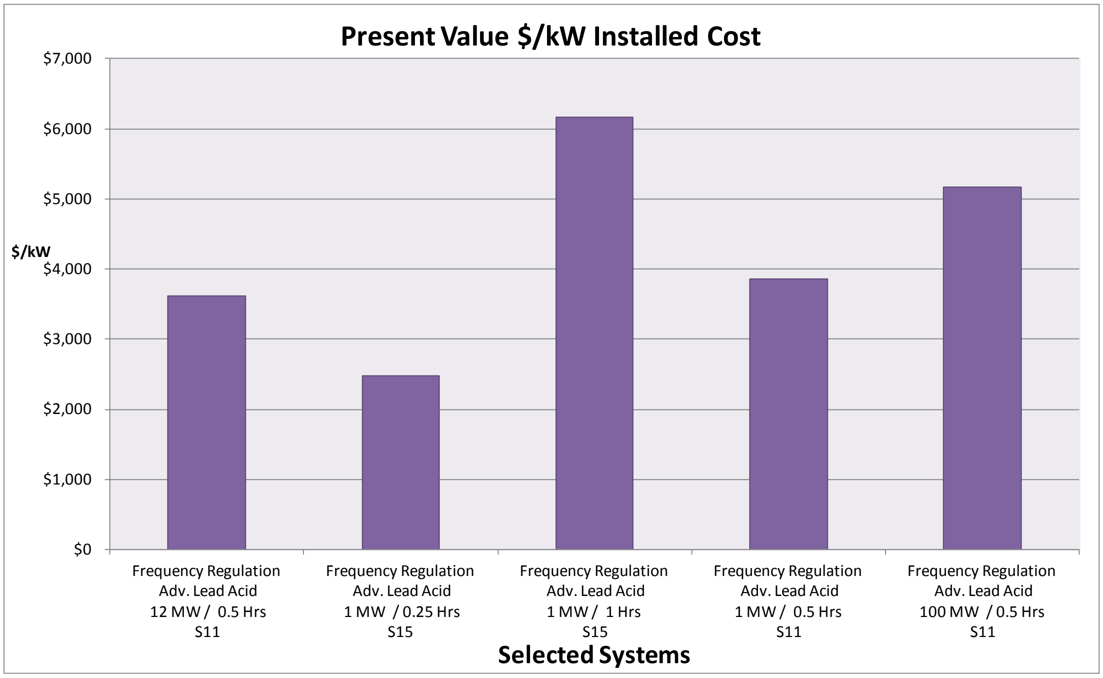

Figure 77. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Frequency Regulation
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

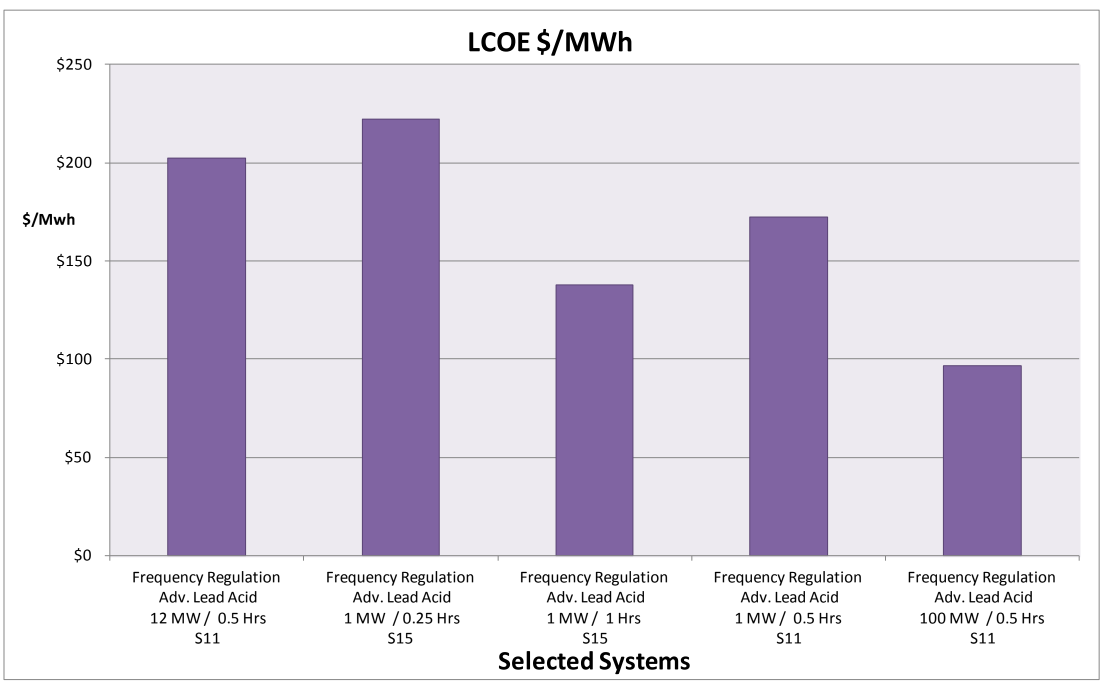

Figure 78. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Frequency Regulation
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

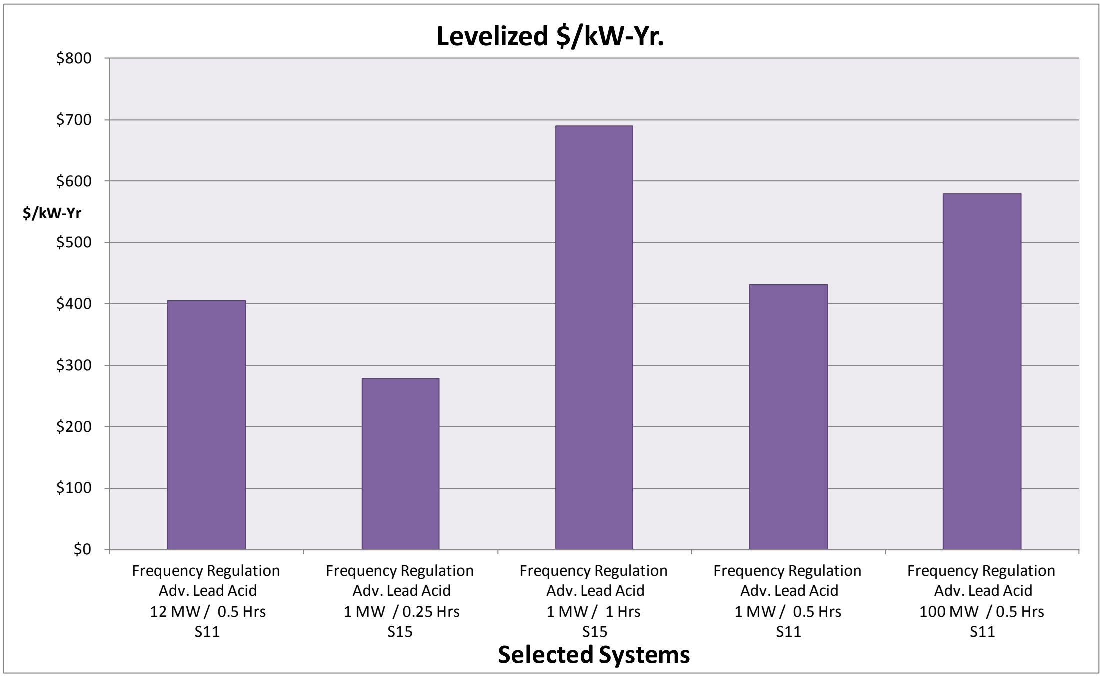

Figure 79. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Frequency Regulation

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

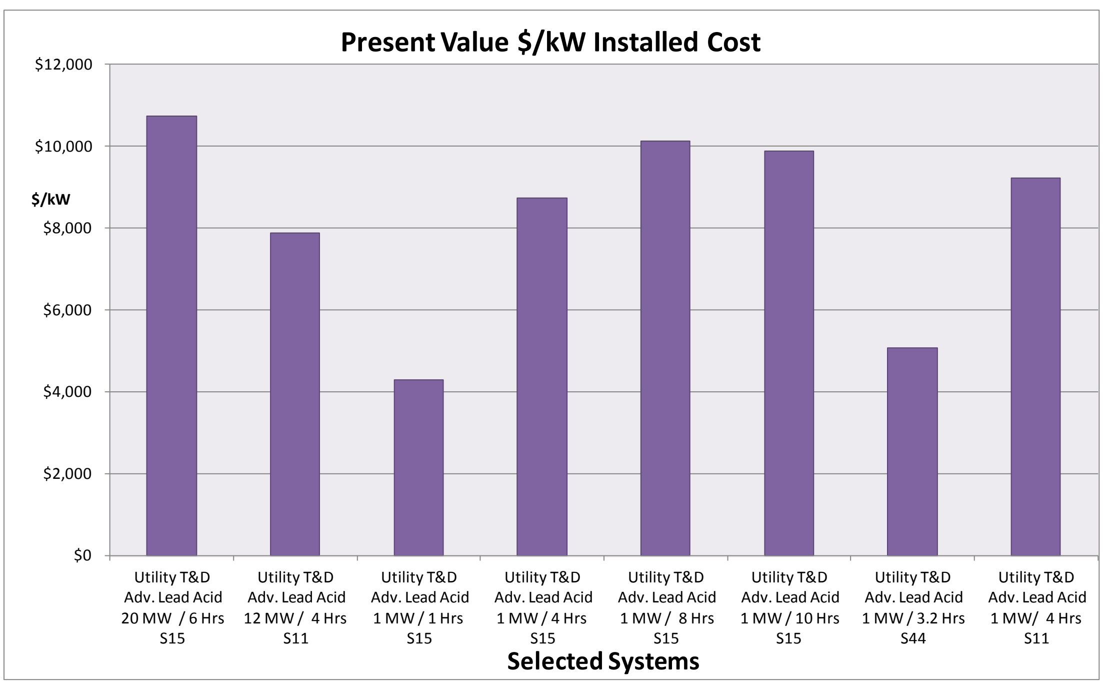

Figure 80. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Transmission and Distribution Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

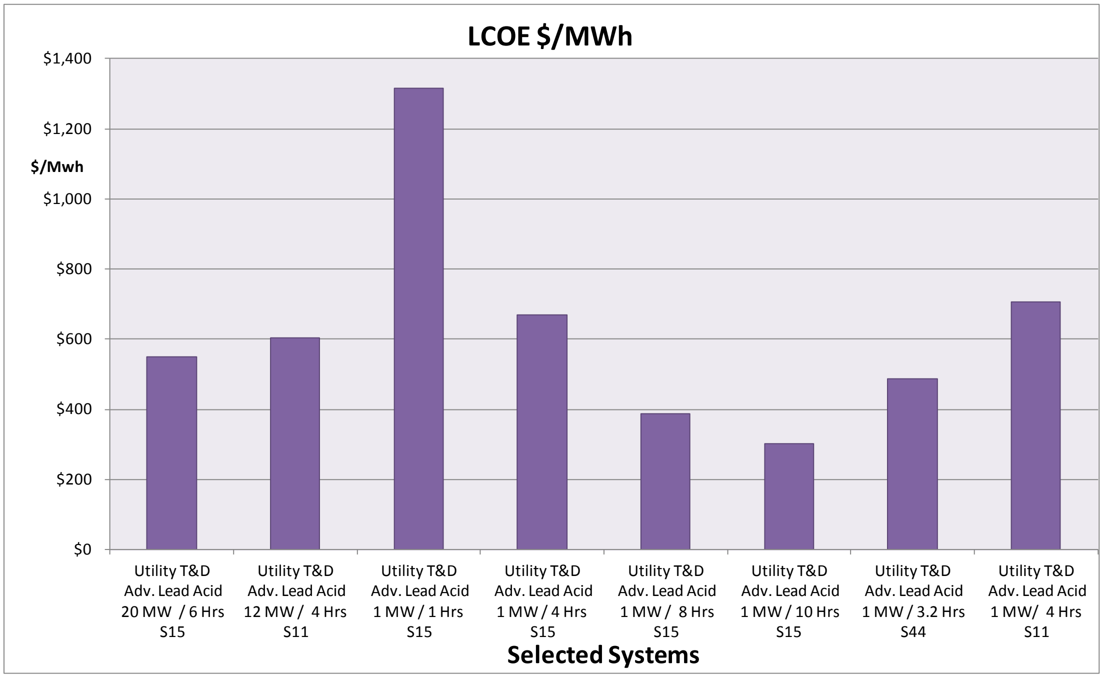

Figure 81. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Transmission and Distribution Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

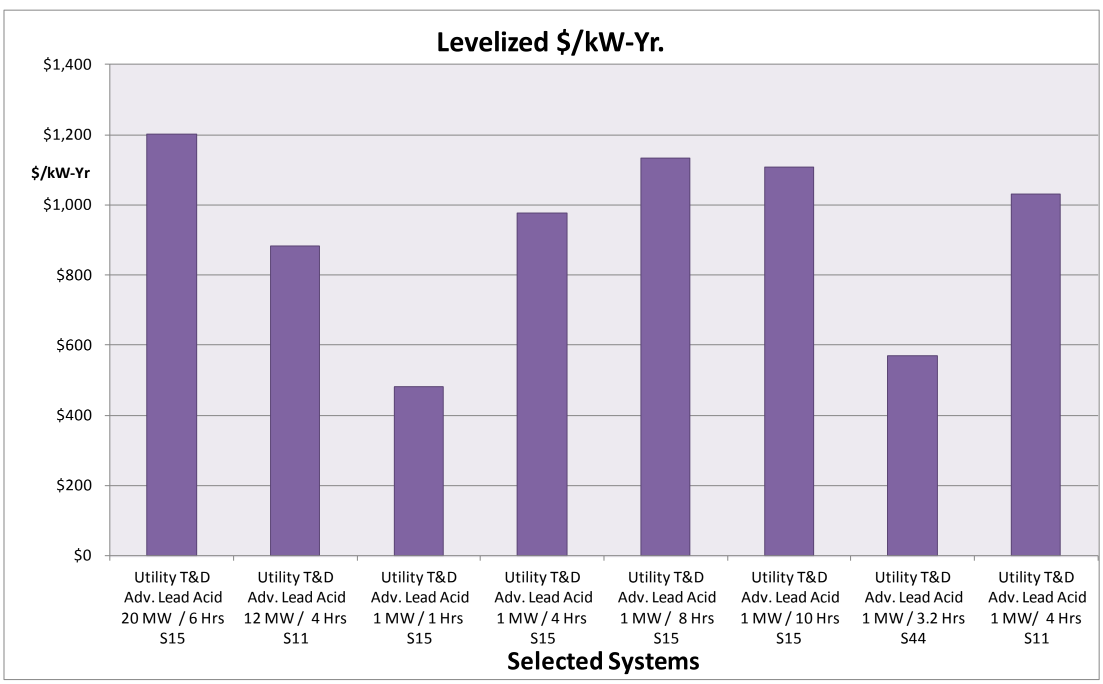

Figure 82. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Transmission and Distribution Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

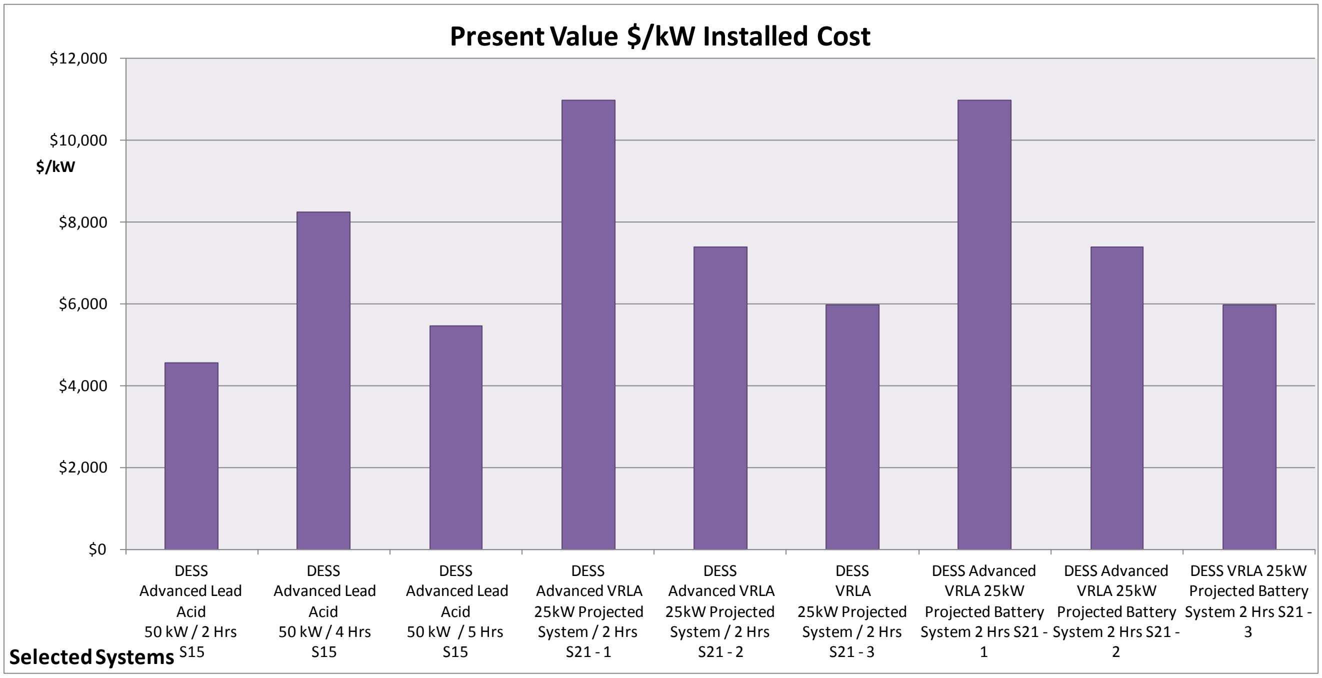

Figure 83. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Distributed Energy Storage System Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

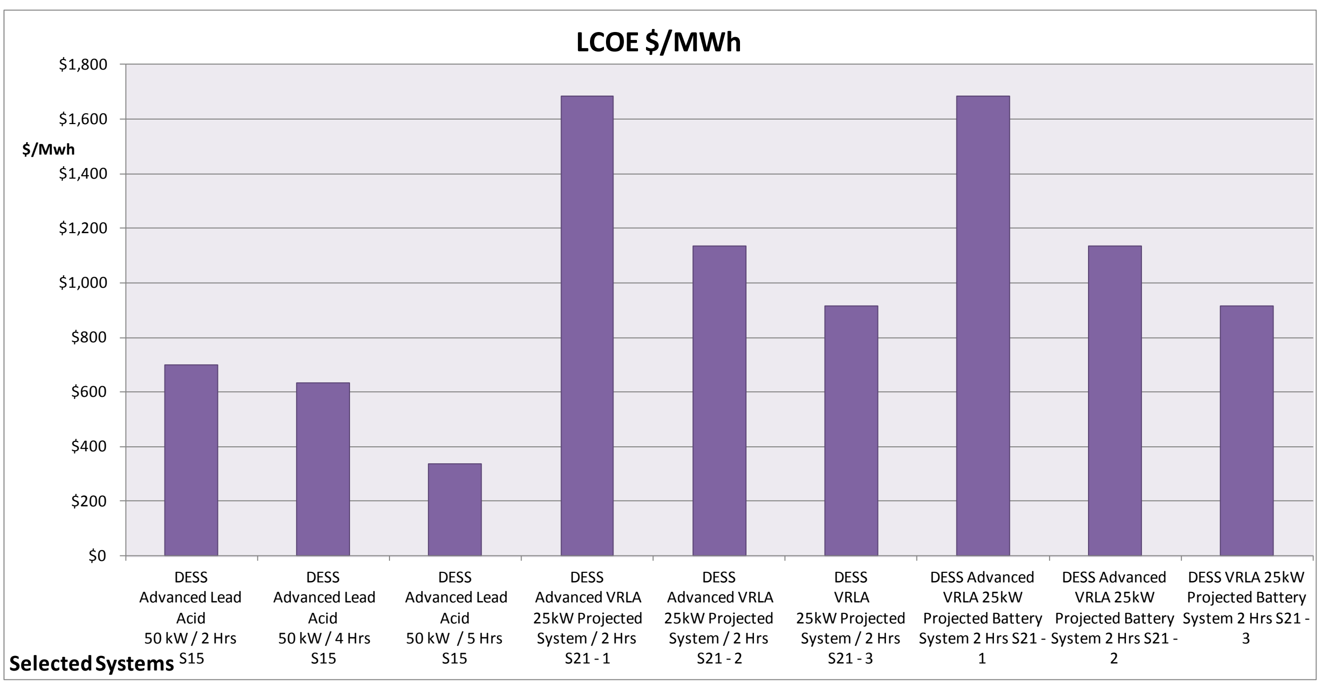

Figure 84. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Distributed Energy Storage System Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

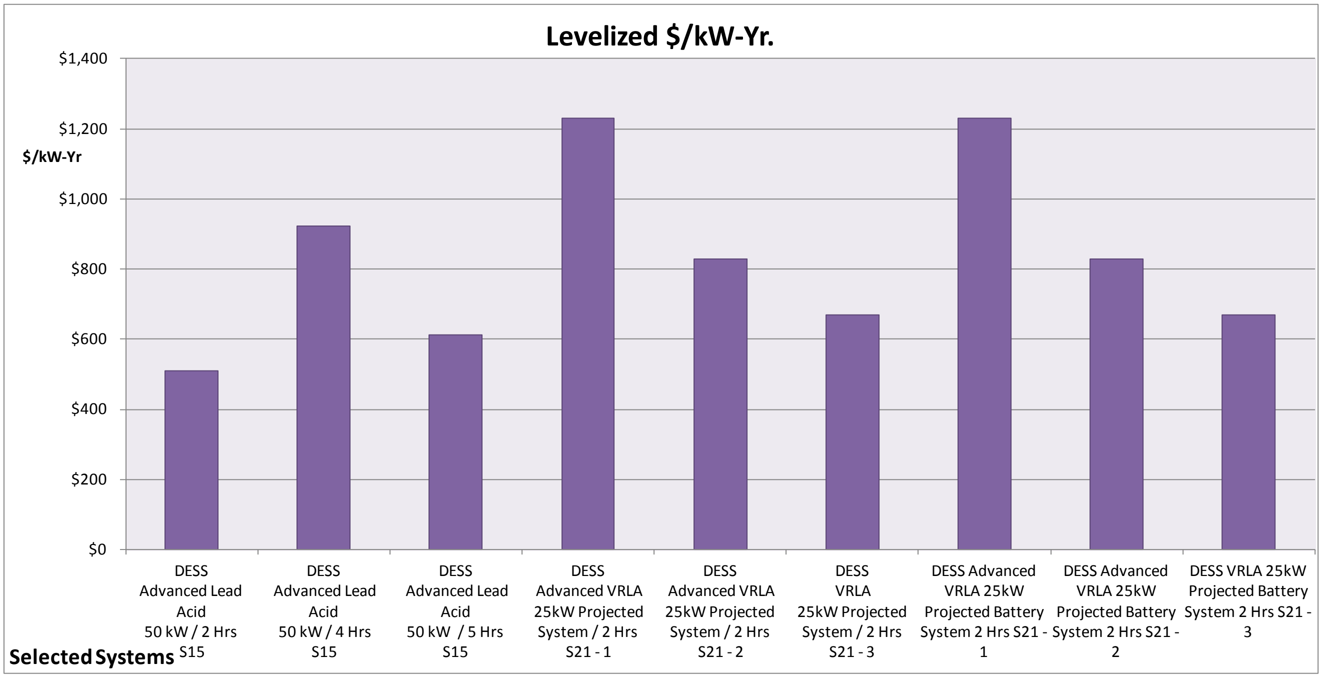

Figure 85. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Distributed Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

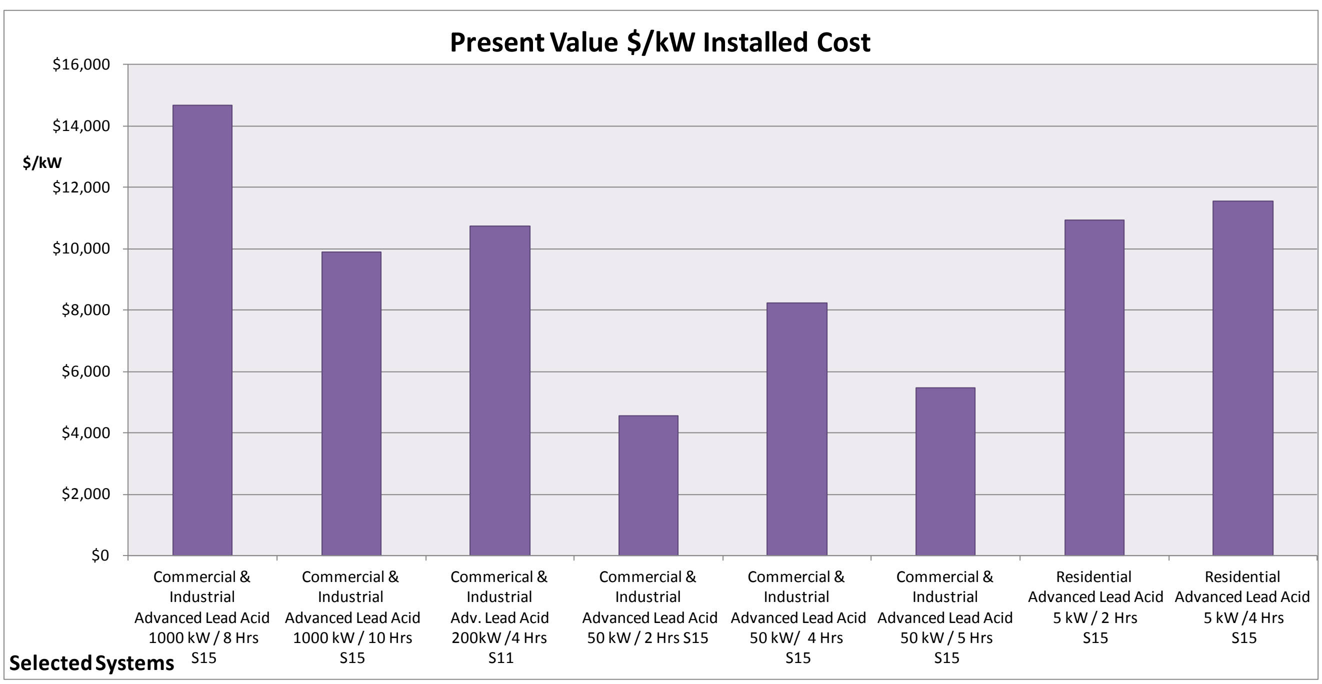

Figure 86. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

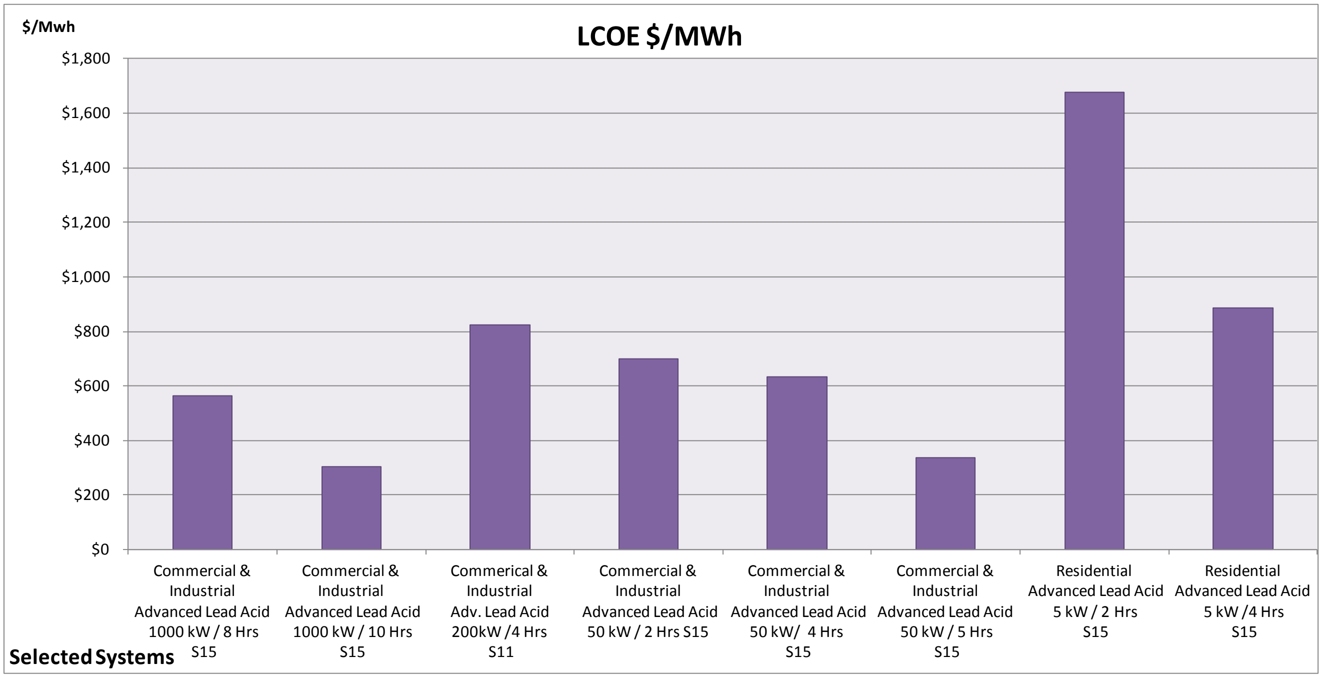

Figure 87. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Commercial and Industrial Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

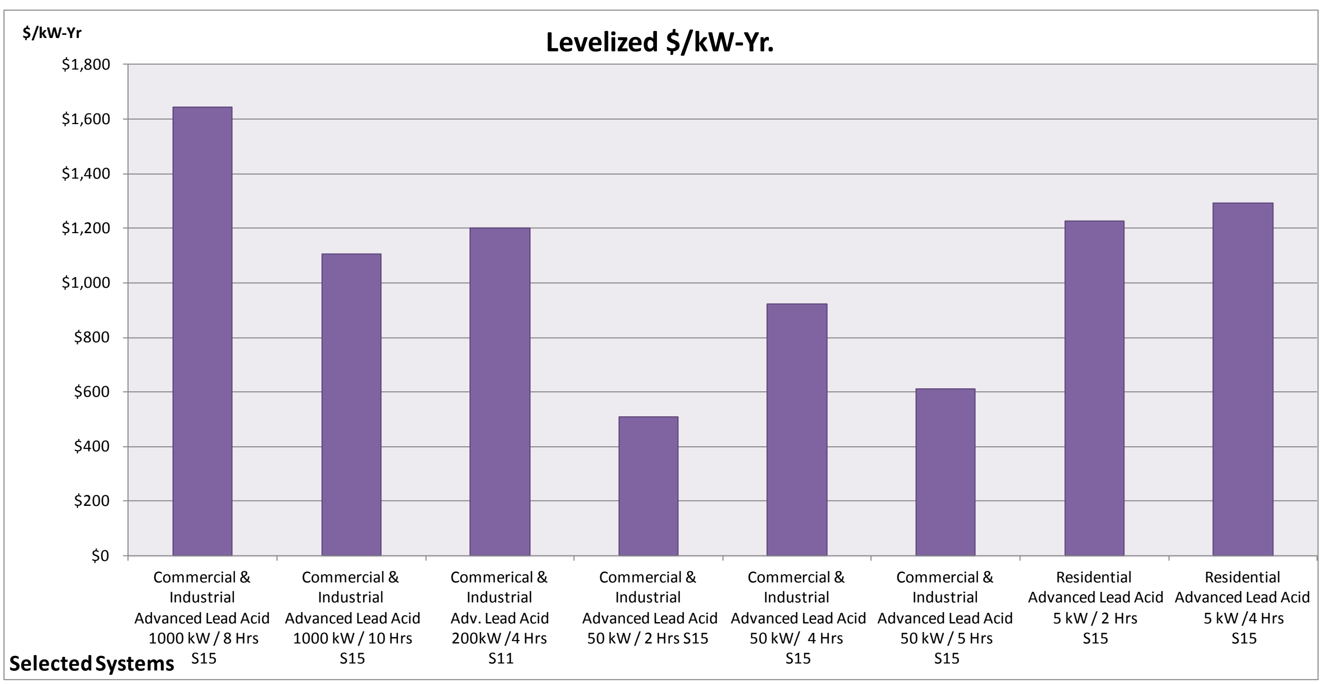

Figure 88. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Commercial and Industrial Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

Additional Lead-acid Battery Resource

1. *New Industry Guidelines for the Maintenance of Stationary Valve-Regulated Lead Acid Batteries*, EPRI ID TR-106769, EPRI, Palo Alto, CA, June 1996.

2. *Chino Battery Energy Storage Power Plant: Engineer-of-Record Report*, EPRI ID Tr-101787, EPRI, Palo Alto, CA, March 1993.

3. *Chino Battery Energy Storage Power Plant: First Year of Operation*, EPRI ID TR-101786, EPRI, Palo Alto, CA, February 1993.

2.12 Flywheel Energy Storage

Technical Description

Flywheels store energy in the form of the angular momentum of a spinning mass, called a rotor. The work done to spin the mass is stored in the form of kinetic energy. A flywheel system transfers kinetic energy into ac power through the use of controls and power conversion systems.

Most modern flywheel systems have some type of containment for safety and performance-enhancement purposes. This containment is usually a thick steel vessel surrounding the rotor, motor-generator, and other rotational components of the flywheel. If the wheel fractures while spinning, the containment vessel would stop or slow parts and fragments, preventing injury to bystanders and damage to surrounding equipment. Containment systems are also used to enhance the performance of the flywheel. The containment vessel is often placed under vacuum or filled with a low-friction gas such as helium to reduce the effect of friction on the rotor. See Figure 89, below.[50]

[50] Ibid.

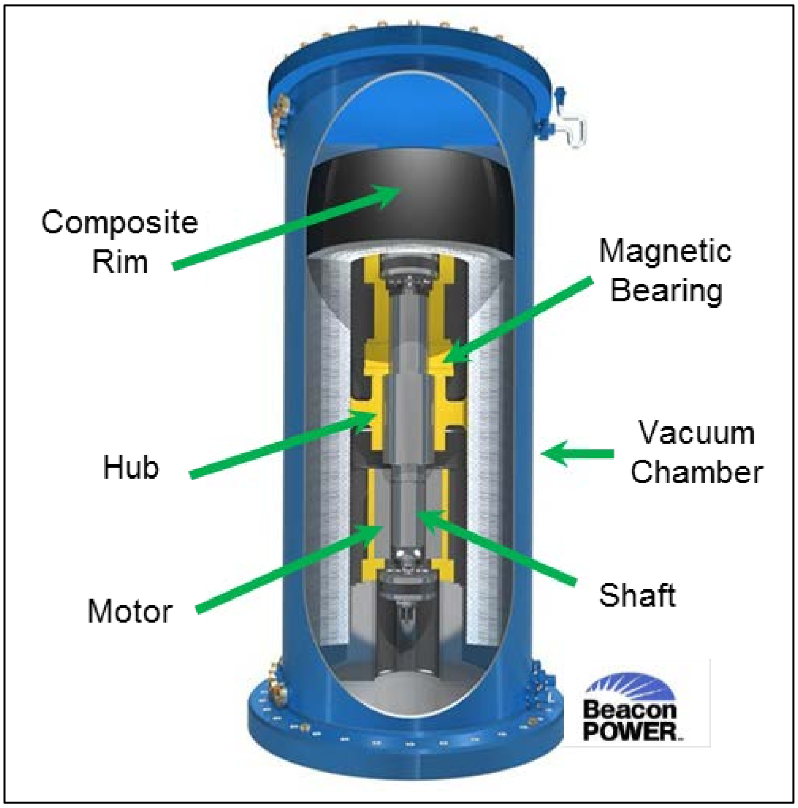

Figure 89. Integrated Flywheel System Package Cutaway Diagram
(Courtesy Beacon Power)[51]

Performance Characteristics

Round-trip efficiency and standby power loss become critical design factors in energy flywheel design because losses represent degradation of the primary commodity provided by the storage system (energy). However, they are largely irrelevant in power flywheel design, although standby losses are a factor in operating cost in comparison with other power technologies that have significantly lower losses. For these reasons, energy flywheels usually require more advanced technologies than power flywheels. These energy flywheels usually have composite rotors enclosed in vacuum containment systems, with magnetic bearings. Such systems typically store between 0.5 kWh and 10 kWh. The largest commercially available systems of this type are in the 2- to 6-kWh range, with plans for up to 25 kWh. All energy flywheels available today are dc output systems. Round-trip efficiencies for energy flywheels are usually between 70% and 80%. The standby losses are very small, typically less than 25 W DC per kWh of storage and in the range one to two percent of the rated output power.[52]

Flywheels can be charged relatively quickly. Recharge times are comparable to discharge times for both power and energy flywheels designs. High-power flywheel systems can often deliver

[51] Ibid.
[52] Ibid.

their energy and recharge in seconds, if adequate recharging power is available. Bidirectional power conversion facilitates this two-way action.[53]

Flywheels generally exhibit excellent cycle life in comparison with other energy storage systems. Most developers estimate cycle life in excess of 100,000 full charge-discharge cycles. The rotor is subject to fatigue effects arising from the stresses applied during charge and discharge. The most common failure mode for the rotor is the propagation of cracks through the rotor over a period of time.[54]

As with any energy storage technology, hazardous conditions may exist around operating flywheels. Considerable effort has gone into making flywheels safe for use under a variety of conditions. The most prominent safety issue in flywheel design is failure of the flywheel rotor while it is rotating. In large, massive rotors, such as those made of steel, failure typically results from the propagation of cracks through the rotor, causing large pieces of the flywheel to break off during rotation. Unless the wheel is properly contained, this type of failure can cause damage to surrounding equipment and injury to people in the vicinity. Large steel containment systems are employed to prevent high-speed fragments from causing damage in the event of failure.[55]

In contrast to many other energy storage systems, flywheel systems have few adverse environmental effects, both in normal operation and in failure conditions. Neither low-speed nor high-speed flywheel systems use hazardous materials, and the machines produce no emissions.[56]

Today's flywheel systems are shorter energy duration systems and not generally attractive for large-scale grid support services that require many kWh or MWh of energy storage. Flywheels charge by drawing electricity from the grid to increase rotational speed and discharge by generating electricity as the wheel's rotation slows. They have a very fast response time of four milliseconds or less, can be sized between 100 kW and 1650 kW, and may be used for short durations of up to one hour. They have very high efficiencies of about 935, with lifetimes estimated at 20 years.

Although flywheels have power densities 5 to 10 times that of batteries—meaning they require much less space to store a comparable amount of power—there are practical limitations to the amount of energy (kWh) that can be stored. A flywheel energy storage plant can be scaled up by adding more flywheel system modules. Typical flywheel applications include power quality and UPS uses, as seen in commercial products. Research is under way to develop more advanced flywheel systems that can store large quantities of energy.

Because flywheel systems are fast-responding and efficient, they are currently being positioned to provide ISO frequency-regulation services. Analysis of such flywheel services have been

[53] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation;
[54] Ibid.
[55] Ibid.
[56] Ibid.

shown to offer system benefits, including avoiding the cycling of large fossil power systems and lower CO_2 emissions. Spindle Grid Regulation, LLC (formerly Beacon Power), is currently demonstrating megawatt-scale flywheel plants with cumulative capacities of 20 MW to support the frequency-regulation market needs of ISOs.[57]

There are also a number of applications that now propose using flywheels as an energy storage medium. These include inrush control, voltage regulation, and stabilization in substations for light rail, trolley, and wind-generation stabilization. The majority of products currently being marketed by national and international-based companies are targeted for power quality (PQ) applications. Another high value application in PQ is short-term bridging through power disturbances or from one power source to an alternate source.[58]

In summary, the applications proposed for flywheel energy storage are the following:

- Power quality/regulation,
- UPS, and
- Grid frequency-regulation services.

Maturity and Commercial Availability

Flywheels are currently being marketed as environmentally safe, reliable, modular, and high-cycle life alternatives to lead-acid batteries for UPS and other power-conditioning equipment designed to improve the quality of power delivered to critical or protected loads. Okinawa Power has installed a 23-MW flywheel system for frequency regulation. Fuji Electric has demonstrated the use of flywheel technology to stabilize wind power generation.[59]

Spindle Grid Regulation, LLC, owns a 20-MW flywheel-based frequency-regulation facility in Stephentown, NY, that commenced operations in 2011 and sells frequency-regulation services to New York Independent System Operator (NYISO) under tariff rates. According to empirical testing performed during early trials, flywheels showed that 1 MW of fast-response flywheel storage produced 20 to 30 MW of regulation service, and that flywheel regulation was two to three times better than an average Independent System Operator –New England (ISO-NE) generator.[60] The facility sits on five acres and comprises 200 flywheels, each with a storage capacity of 100kW. Stephentown was originally developed and built by Beacon Power. Beacon also operates the facility. Spindle is also developing a second 20-MW facility in Hazle Township, PA, with financial assistance from the DOE and the Commonwealth of Pennsylvania.

[57] *Large-Scale Energy Storage in Decarbonised Power Grids*, Inage, Shin-ichi, International Energy Agency, Paris, France, 2009.
[58] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation.
[59] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits*, PI: Dan Rastler, EPRI ID 1020676, EPRI, Palo Alto, CA, 2010.
[60] *Application of Fast-Response Energy Storage in NYISO for Frequency Regulation Services*, Beacon Power Corporation, Portland, OR, April 2010.

Figure 90 shows a 1-MW system installed at Beacon Power's headquarters in Tyngsboro, MA.

Figure 90. 1-MW Smart Energy Matrix Plant
(Photo courtesy: Beacon Power)

Table 15 is a technology dashboard that shows the status of technology development for flywheel energy storage systems.

Table 15. Technology Dashboard: Flywheel Energy Storage Systems

Technology Development Status	Demonstration status for Frequency Regulation C	Commercial experience in Power Quality UPS applications Pilots in ISO A/S Market applications
Confidence of Cost Estimate	B	Vendor quotes and system installation estimates.
Accuracy Range	B	-15% to +15%
Operating Field Units	10 or more	In a 20-MW application. Numerous uses in power quality applications.
Process Contingency	1 – 5%	Uncertain long-term life and performance of the flywheel subsystem
Project Contingency	5 – 10%	

Flywheel Storage Life-Cycle Cost Metrics

Life-cycle cost analysis is illustrated in Figure 91, Figure 92, and Figure 93. The estimates are based on capital, O&M data, and replacement costs from the data sheets in Appendix B . A simple dispatch was assumed, based on 5000 cycles per year, $290 per kW replacement costs every 5 years, and IOU financing. See Appendix B for key input assumptions.

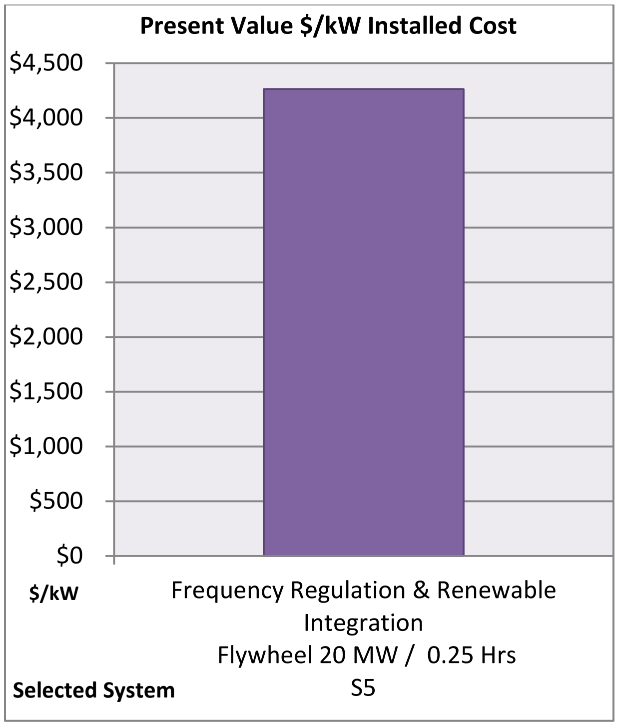

Figure 91. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Flywheel Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

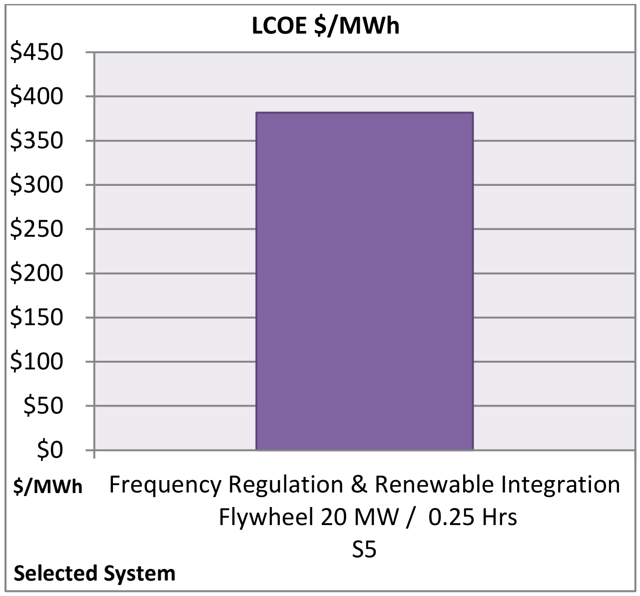

Figure 92. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Flywheel Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

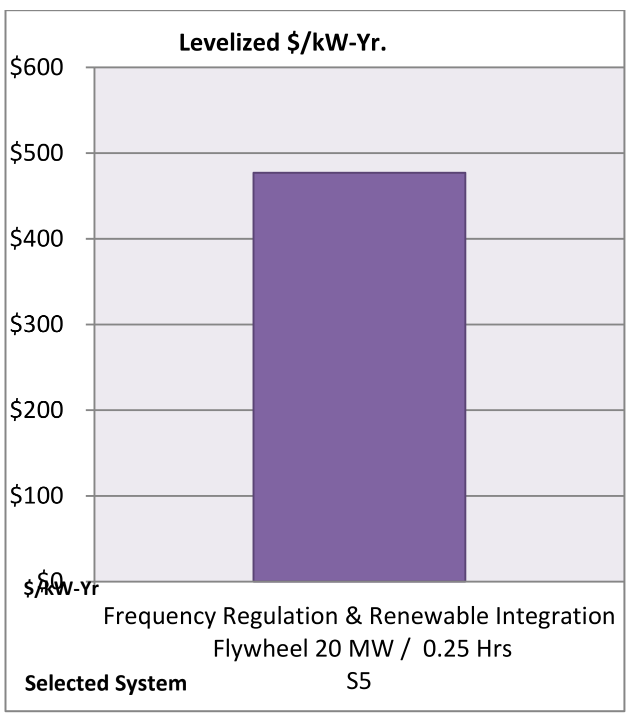

Figure 93. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Flywheel Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

Additional Resources for Flywheels

1. *Flywheel Energy Storage*, EPRI ID TR-108378, September 1997.
2. *Flywheels for Electric Utility Energy Storage*, EPRI ID TR-108889, December 1999.

2.13 Lithium-ion Family of Batteries

Technical Description

In the past two years, Li-ion battery technology has emerged as the fasted growing platform for stationary storage applications. Already commercial and mature for consumer electronic applications, Li-ion is being positioned as the leading technology platform for plug-in hybrid electric vehicles (PHEVs) and all-electric vehicles, which will use larger-format cells and packs with capacities of 15 to 20 kWh for PHEVs and up to 50 kWh for all-electric vehicles.

The most common types of liquid Li-ion cells are cylindrical and prismatic cell. They are found in notebook computers and other portable power applications. Another approach, prismatic polymer Li-ion technology, is generally only used for small portable applications such as cellular phones and MP3 players. Rechargeable Li-ion batteries are commonly found in consumer electronic products, which make up most of the worldwide production volume of 10 to 12 GWh per year. Compared to the long history of lead-acid batteries, Li-ion technology is relatively new. There are many different Li-ion chemistries, each with specific power-versus-energy characteristics. Large-format prismatic cells are currently the subject of intense R&D, scale-up, and durability evaluation for near-term use in hybrid EVs, but are still only available in very limited quantities as auto equipment manufacturers gear up production of PHEVs.[61]

A Li-ion battery cell contains two reactive materials capable of undergoing an electron transfer chemical reaction. To undergo the reaction, the materials must contact each other electrically, either directly or through a wire, and must be capable of exchanging charged ions to maintain overall charge neutrality as electrons are transferred. A battery cell is designed to keep the materials from directly contacting each other and to connect each material to an electrical terminal isolated from the other material’s terminal. These terminals are the cell’s external contacts (see Figure 94).

[61] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits*, PI: Dan Rastler, EPRI ID 1020676, EPRI, Palo Alto, CA, September 2010.

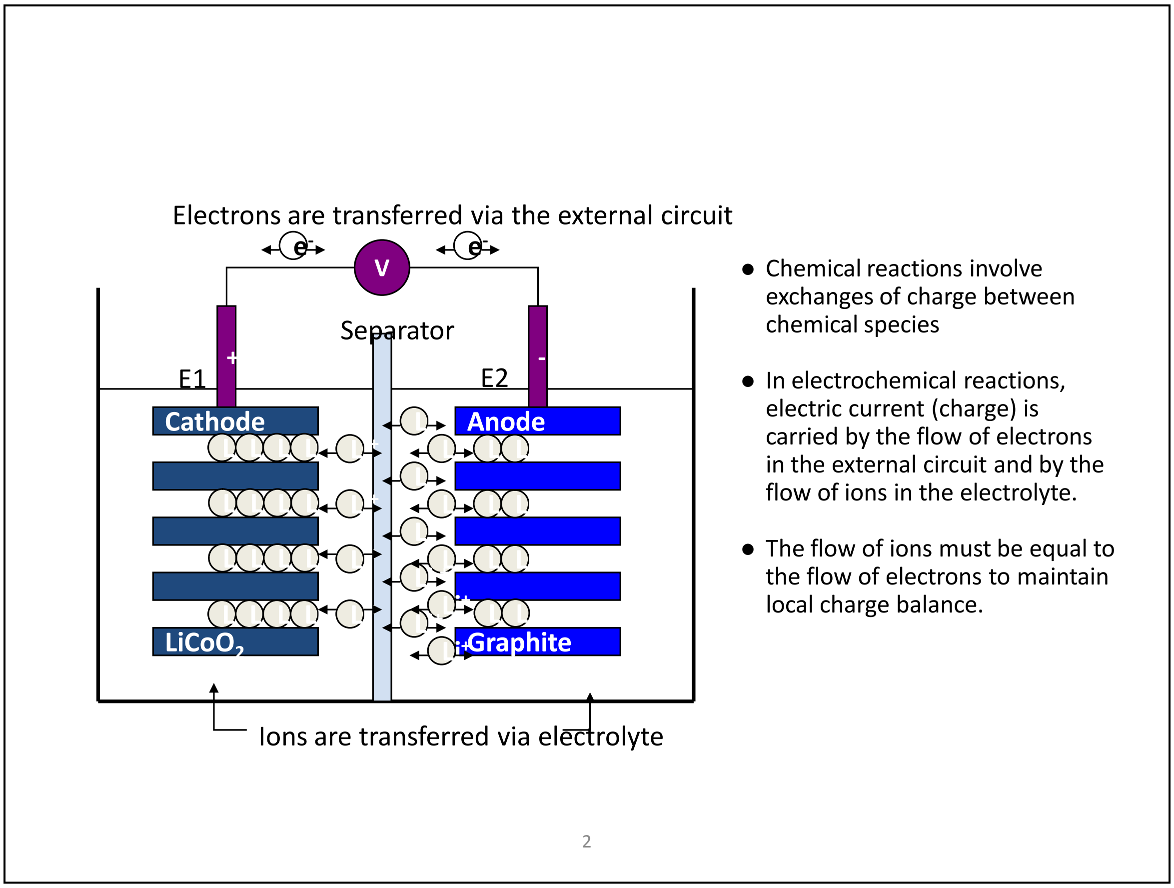

Figure 94. Principles of a Li-ion Battery

Inside the cell, the materials are ionically, but not electronically, connected by an electrolyte that can conduct ions, but not electrons. As shown in Figure 95, this is accomplished by building the cell with a porous insulating membrane, called the separator, between the two materials and filling that membrane with an ionically conductive salt solution. Thus this electrolyte can serve as a path for ions, but not for electrons. When the external terminals of the battery are connected to each other through a load, electrons are given a pathway between the reactive materials, and the chemical reaction proceeds with a characteristic electrochemical potential difference or voltage. Thus there is a current and voltage (i.e., power) applied to the load.[62]

Maturity and Commercial Availability

The large manufacturing scale of Li-ion batteries (estimated to be approximately 30 GWh by 2015) could result in potentially lower-cost battery packs – which could also be used and integrated into systems for grid-support services that require less than 4 hours of storage. Many stationary systems have been deployed in early field trials to gain experience in siting, grid integration, and operation. Li-ion systems dominate the current deployment landscape for grid-

[62] Ibid.

scale storage systems in the United States. Figure 96 illustrates some of the Li-ion energy storage system deployments underway that have accelerated in the past two years. The stars represent the most significant projects; several other Li-ion projects are underway elsewhere.

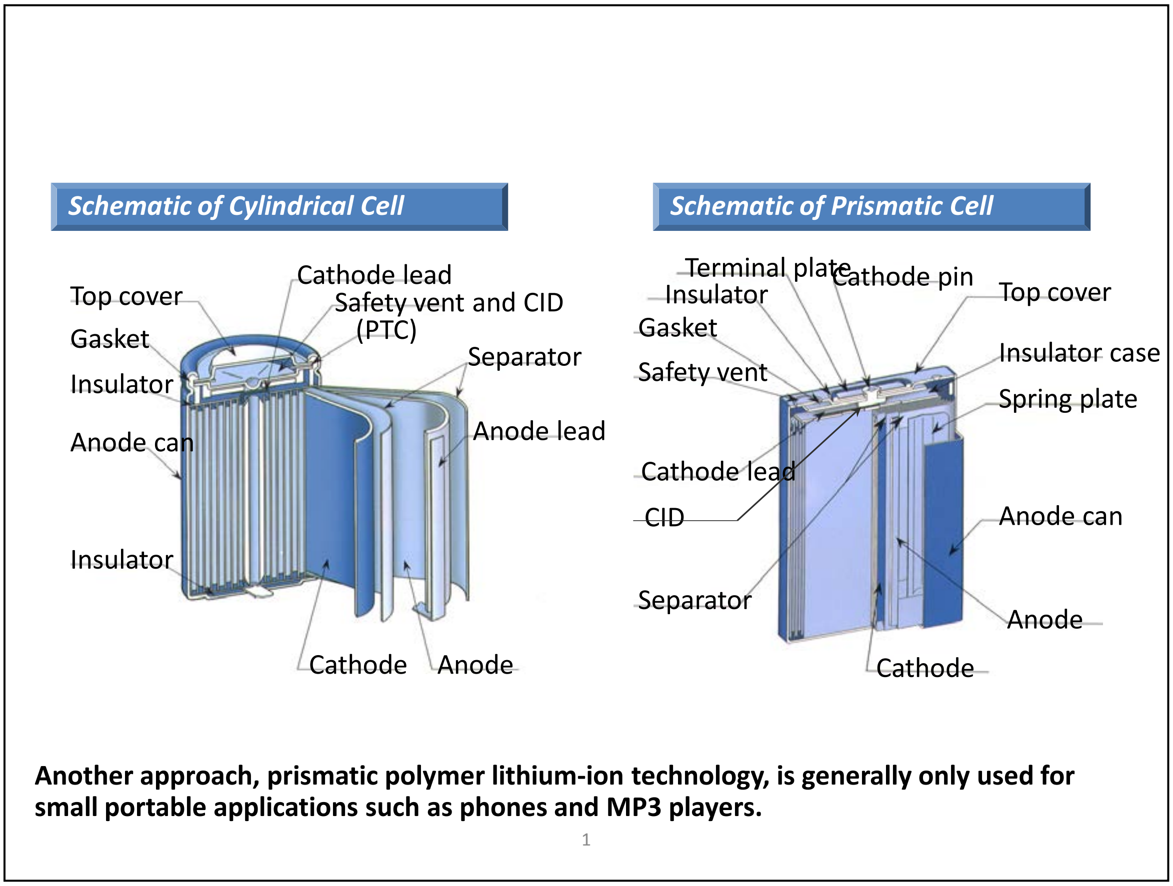

Figure 95. Illustrative Types of Li-ion Cells

Figure 96. Locations of Current and Planned U.S. Li-ion System Grid Demonstrations

Early system trial demonstrations are underway using small 5- to 10-kW/20-kWh distributed systems and large 1-MW/15-minute fast-responding systems for frequency regulation. Several electric utilities are also planning to deploy Distributed Energy Storage Systems (DESSs) in the 25- to 50-kW size range on the utility side of the meter with energy durations ranging from 1 to 3 hours. Some systems have islanding capability, which can keep homeowners supplied with power for 1 to 3 hours if the grid goes down. Several customer-side-of-meter commercial and residential applications are also underway. The first large commercial peak-shaving system (2 MW/4 MWh) has been deployed by Chevron Energy Solutions. AES Energy Storage LLC has deployed more than 50 MW of systems as an independent power producer (IPP) for frequency regulation and spinning reserve services. Utilities are also deploying megawatt-scale units for PV integration and distribution grid support. In addition, several vendors are implementing small residential energy storage systems that when aggregated could provide system and utility benefits. In total, more than an estimated 100 MW of grid-connected advanced Li-ion battery systems have been deployed for demonstration and commercial service.

Several representative Li-ion systems from different suppliers are shown in Figure 97, Figure 98, and Figure 99. Two residential systems are shown in Figure 100. On the left is a 5-kW/7.8-kWh residential energy storage system installed at Sacramento Municipal Utility District's Anatolia all SolarSmart Homes development. The suppliers are Silent Power, GridPoint, and SAFT. On the right is a 2.7-kW 10.8-kWh system supplied by Sunverge Energy with smart grid software that enables aggregation of many units allowing utilities, end users, or third parties to buy and sell electricity and manage energy needs based on individual interests.

Figure 97. AES Storage LLC's Laurel Mountain Energy Storage
(Supplies 32 MW of regulation in PJM using Li-ion batteries supplied by A123 Systems)

Photo courtesy of Chevron Energy Solutions Company

Figure 98. A 2-MW/4-MWh Li-ion Energy Storage System

Figure 99. A 30-kW/34-kWh Distributed Energy Storage Unit
(Being Installed and Inspected at the Sacramento Municipal Utility District's Anatolia SolarSmart Homes Development. Suppliers are SAFT, Grid Point, and Power Hub)

Figure 100. Residential Energy Storage and Energy Management Systems

Table 16 presents a technology dashboard for Li-ion battery systems for stationary grid services.

Table 16. Technology Dashboard: Lithium-ion Battery Systems

Technology Development Status	Demonstration C	Systems verified in several field demonstrations in a variety of use cases.
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	C	-20% to +10%
Operating Field Units	32 MW in frequency regulation service 0.5 MW/1 MWh 25 – 50 kW/^{2} hr	Numerous small demonstrations in the 5-kW to 25-kW sizes are currently underway. MW-scale short-energy-duration systems are being operated in frequency regulation applications. MW class for grid support and PV smoothing being introduced 2-MW/4-MWh system installed in an end-use customer peak shaving application
Process Contingency	10 – 15% Depends on chemistry	Battery management system, system integration, and cooling need to be addressed. Performance in cold climate zones needs to be verified.
Project Contingency	5 – 10%	Limited experience in grid-support applications, including systems with utility grid interface. Uncertain cycle life for frequency regulation applications.

Li-ion Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of selected systems is illustrated in Figure 101 through Figure 112 for each application. The estimates are based on capital, O&M data, and battery replacement costs from the Li-ion data sheets in Appendix B. A simple dispatch was assumed for bulk, utility T&D, C&I energy management, and residential energy management. Life-cycle estimates are based on IOU financial assumptions of 365 cycles annually for 15 years. See Appendix B for discussion of life-cycle cost methods.

For the frequency regulation applications, a simple dispatch was assumed based on each system operating 5000 cycles per year. See Appendix B for discussion of life-cycle costs methods for this application.

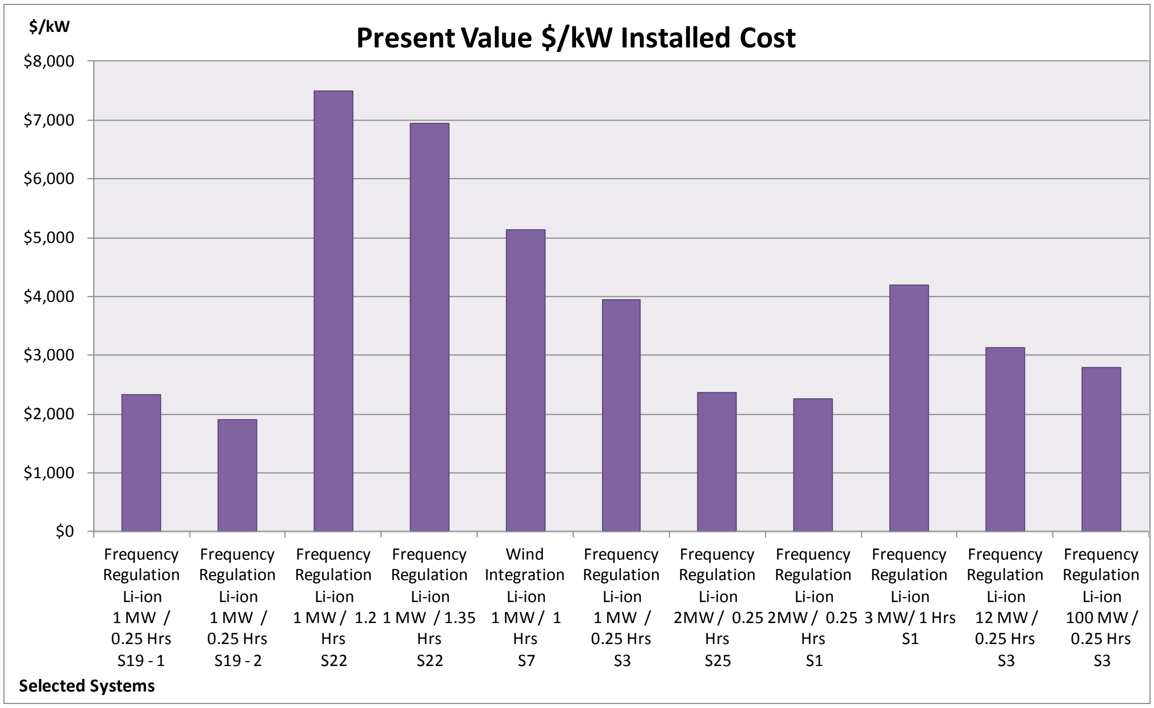

Figure 101. Present Value Installed Cost in $/kW for Li-ion Batteries in Frequency Regulation and Renewable Integration Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

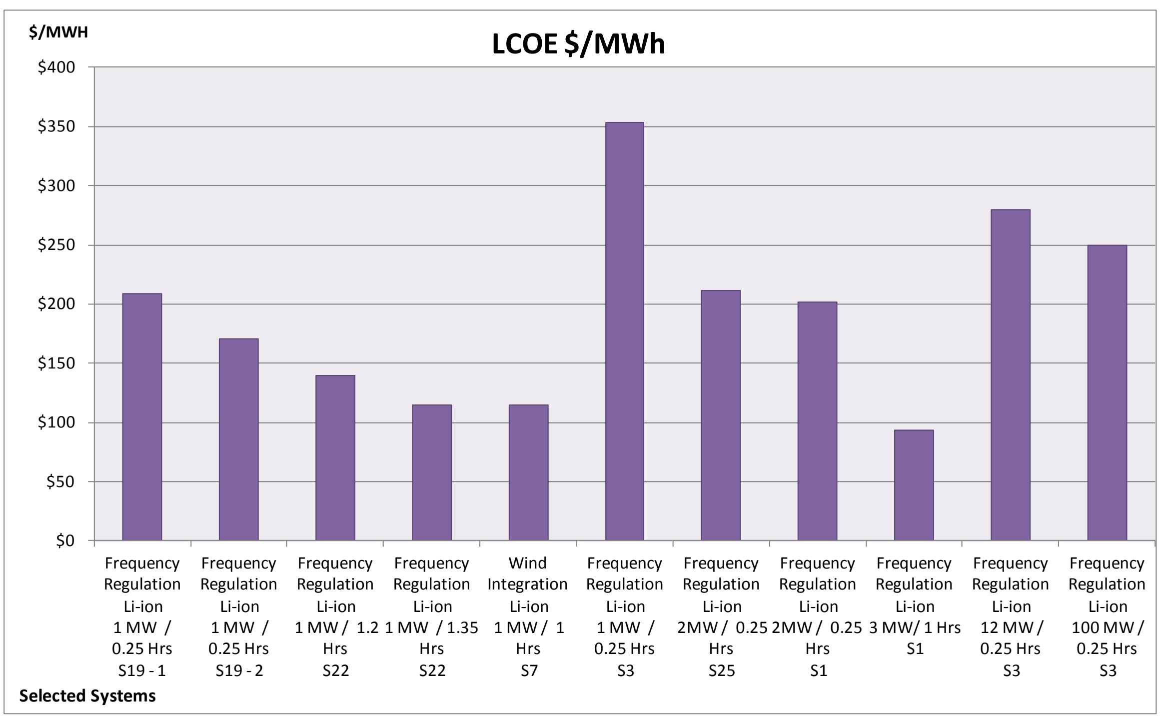

Figure 102. LCOE in $/MWh for Li-ion Batteries in Frequency Regulation and Renewable Integration Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

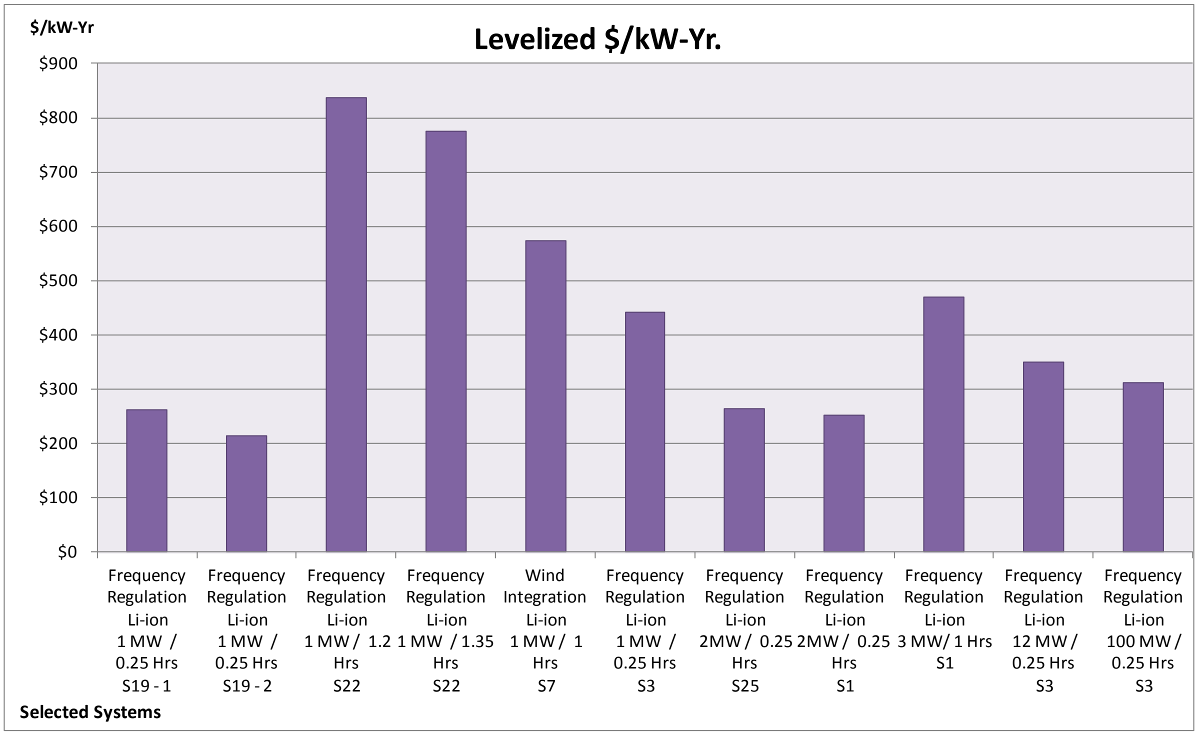

Figure 103. Levelized $/kW-yr for Li-ion Batteries in Frequency Regulation and Renewable Integration Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

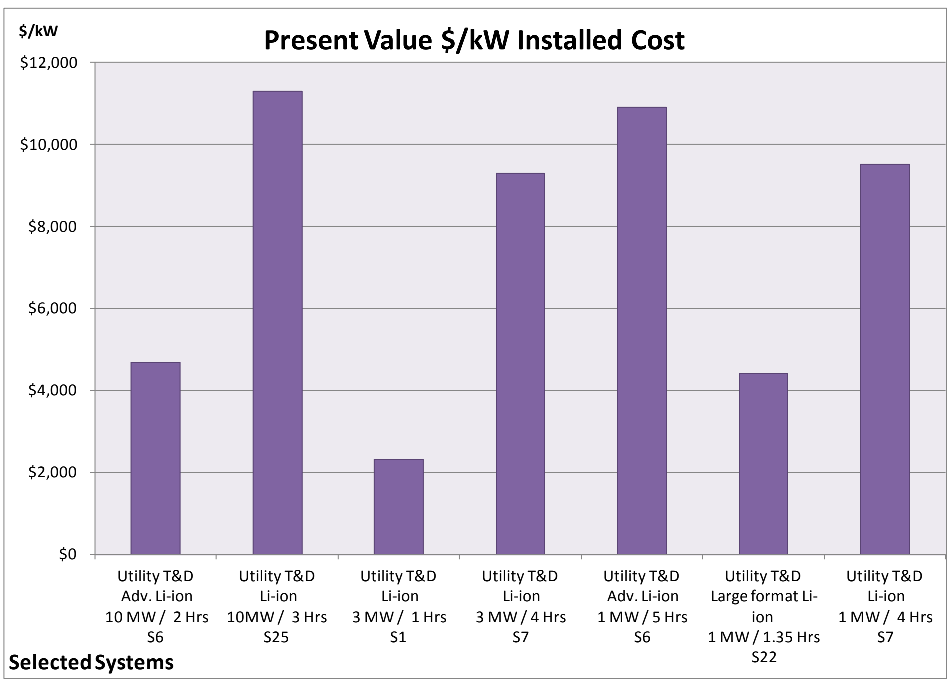

Figure 104. Present Value Installed Cost in $/kW for Li-ion Batteries in Transmission and Distribution Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

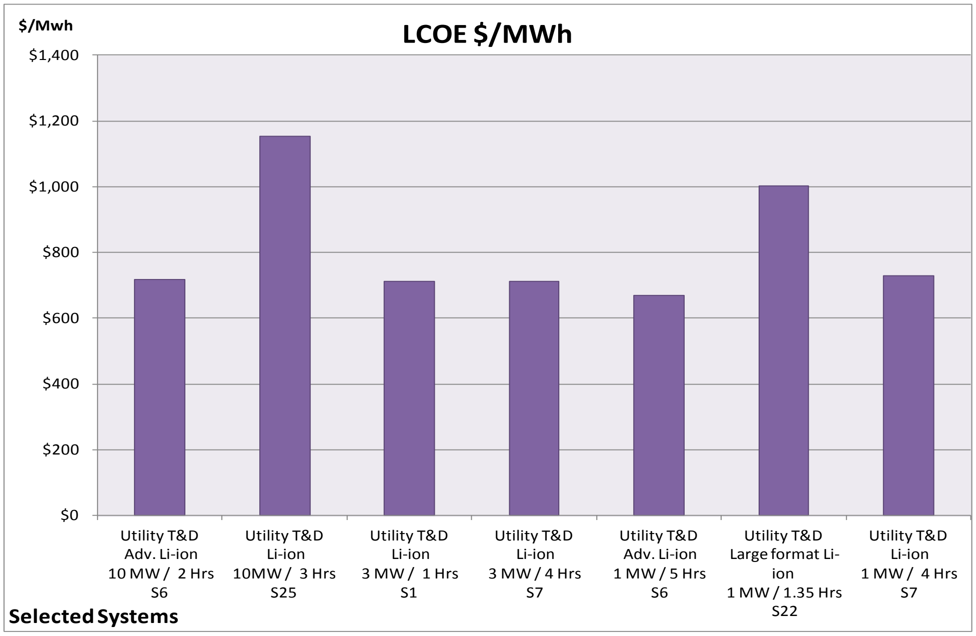

Figure 105. LCOE in $/MWh for Li-ion Batteries in Transmission and Distribution Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

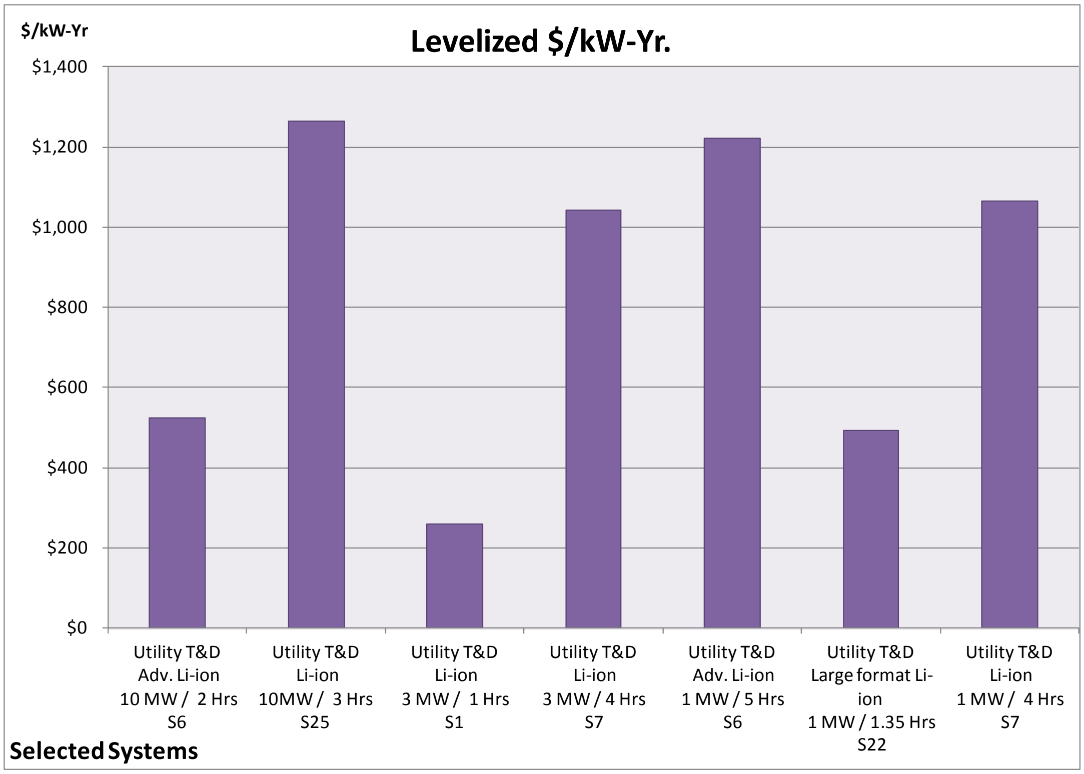

Figure 106. Levelized $/kW-yr for Li-ion Batteries in Transmission and Distribution Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

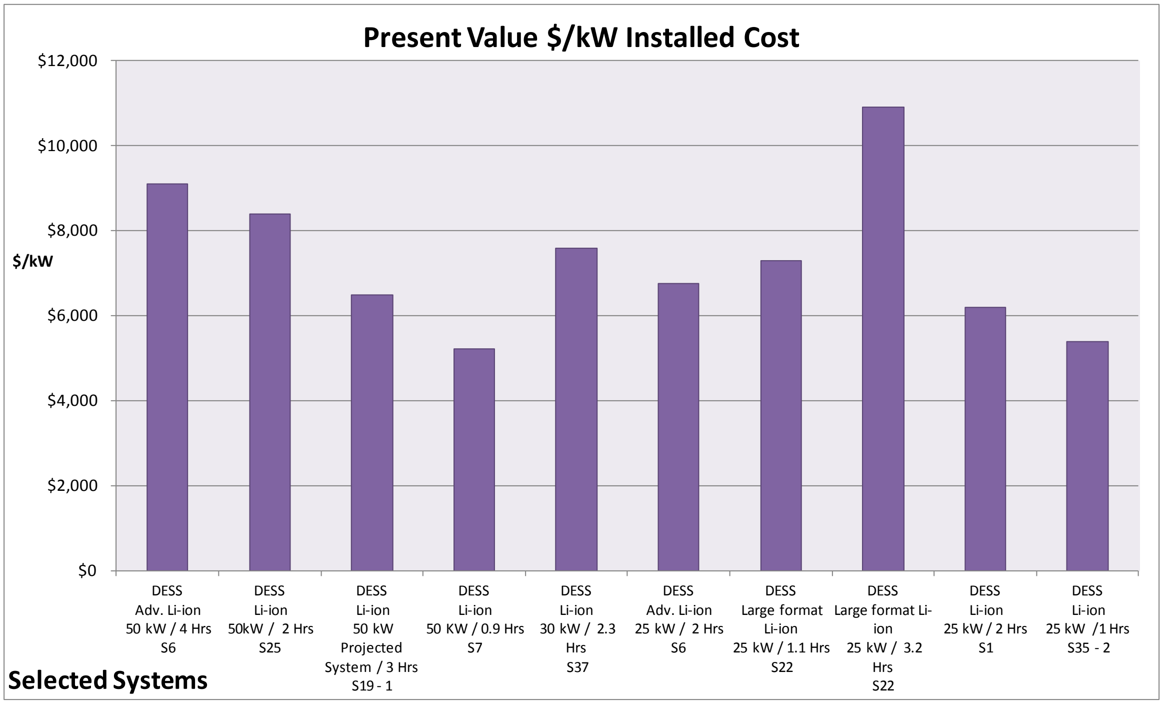

Figure 107. Present Value Installed Cost in $/kW for Li-ion Batteries in Distribute Energy Storage System Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

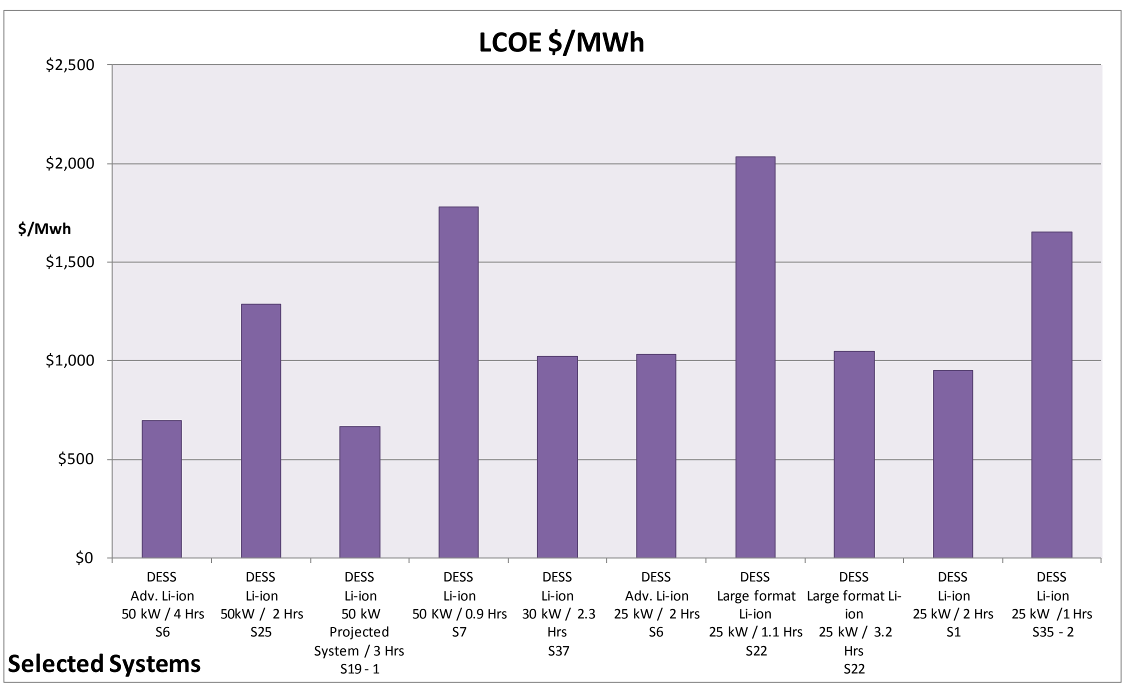

Figure 108. LCOE in $/MWh for Li-ion Batteries in Distribute Energy Storage System Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

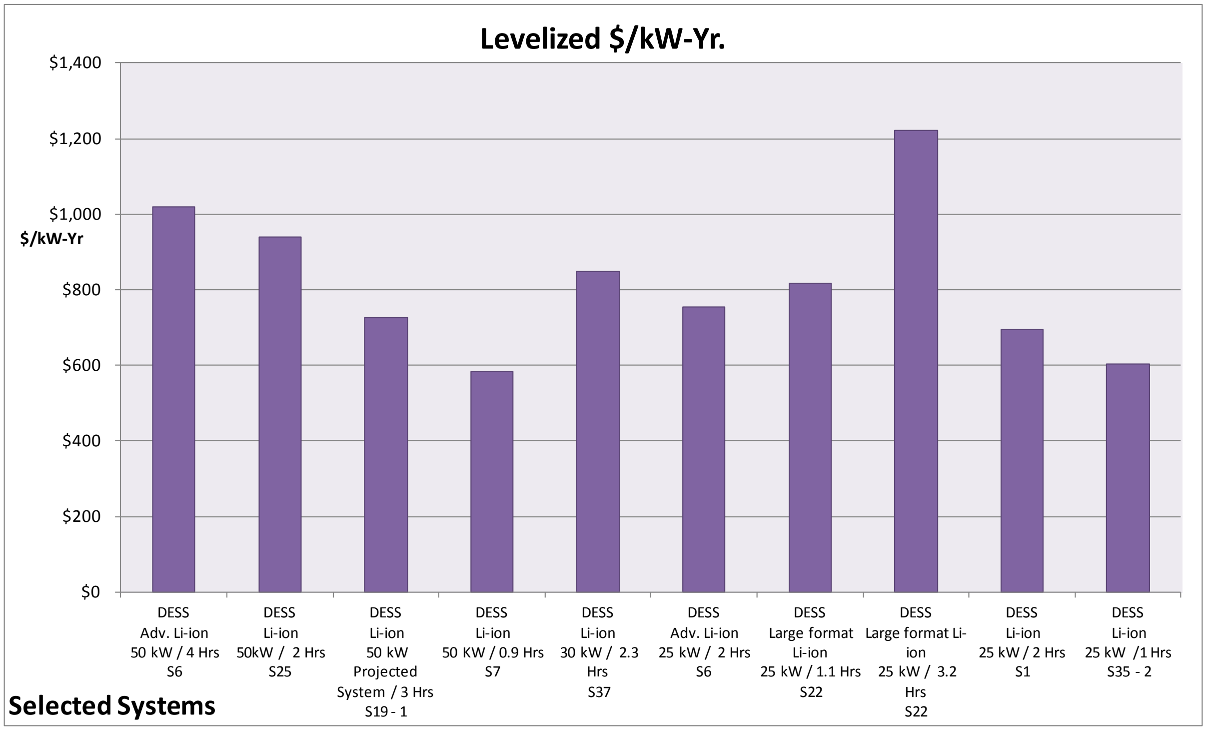

Figure 109. Levelized $/kW-yr for Li-ion Batteries in Distribute Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

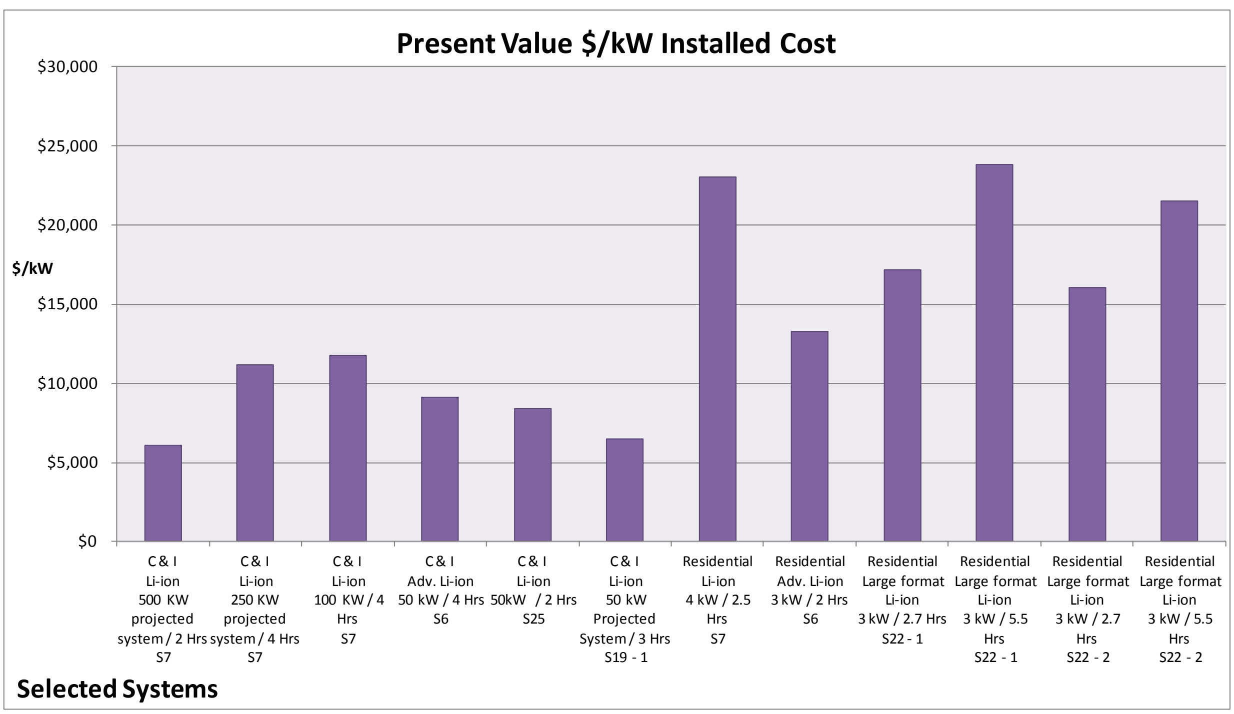

Figure 110. Present Value Installed Cost in $/kW for Li-ion Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

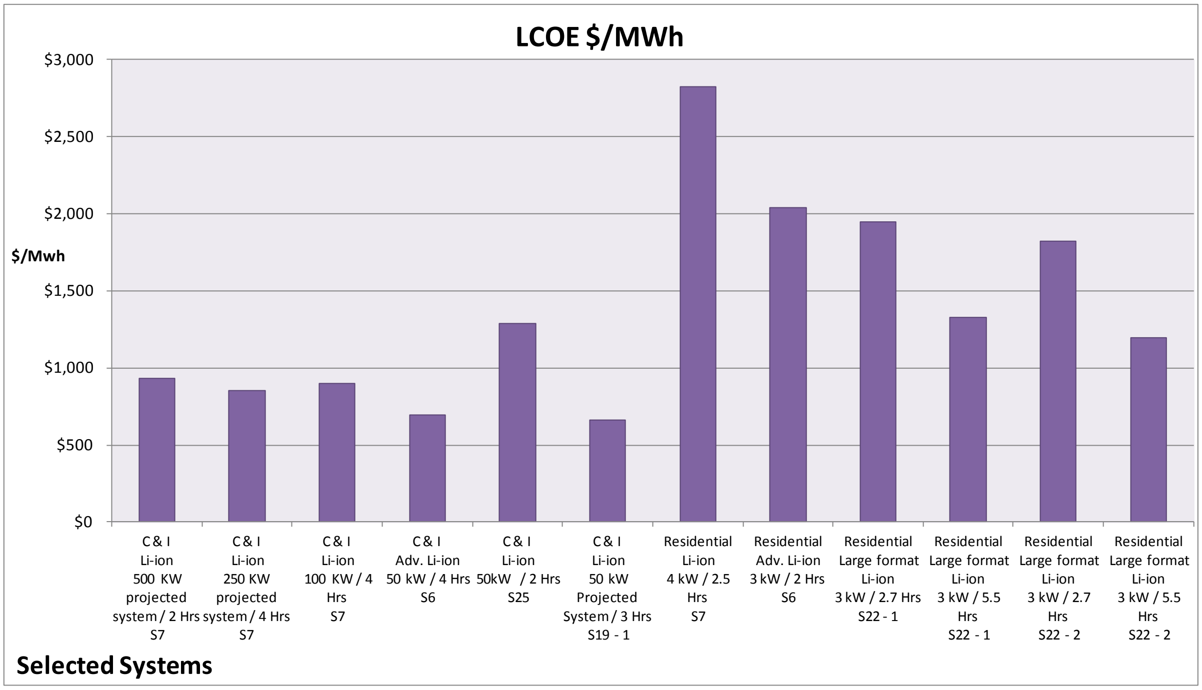

Figure 111. LCOE in $/MWh for Li-ion Batteries in Commercial and Industrial Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

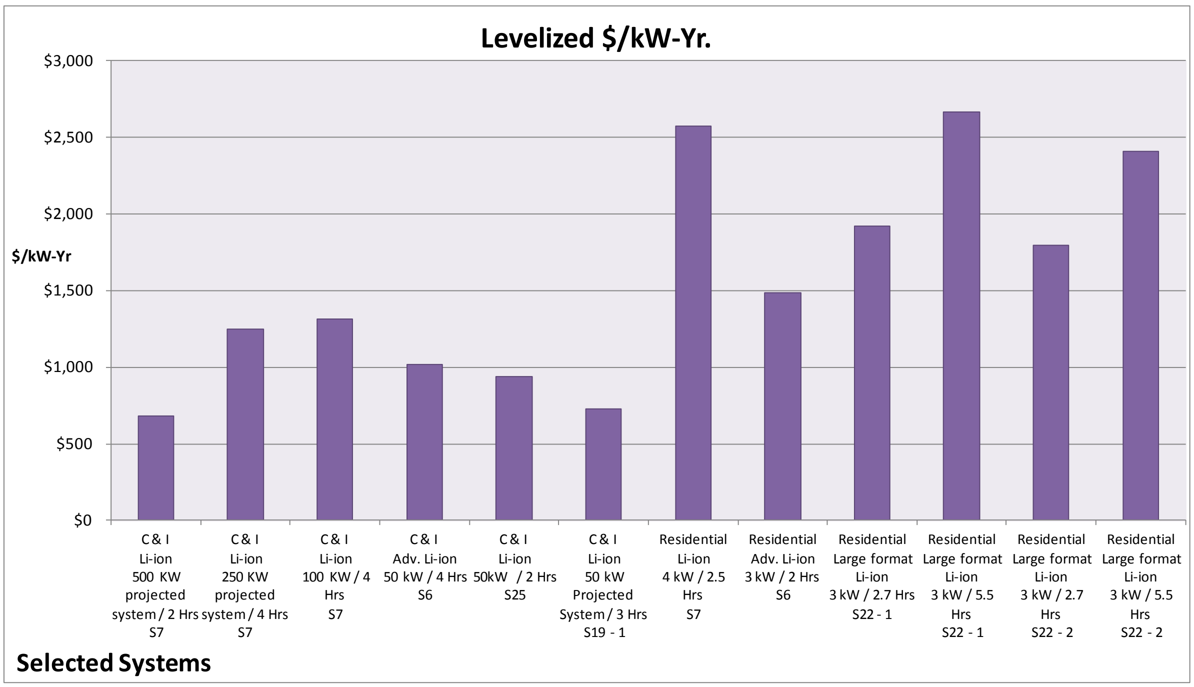

Figure 112. Levelized $/kW-yr for Li-ion Batteries in Commercial and Industrial Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)
(All system costs are based on 5000 cycles per year)

Additional Resources for Li-ion Batteries

1. *Technical Specification for a Transportable Energy Storage System for Grid Support Using Commercially Available Li-ion Technology*, EPRI ID 1025573, EPRI, Palo Alto, CA, July 2012.

2. *Demonstration Initiative for a Grid Support Storage System using Li-ion Technology: Phase I Report*, EPRI ID 1025574, EPRI, Palo Alto, CA, August 2012.

3. *Electricity Energy Storage Technology Options*, EPRI ID 1020676, EPRI, Palo Alto, CA, December 2010.

2.14 Emerging Technologies

There are many other types of energy storage technologies, both mature and still in the R&D phase, that are not discussed in this report. Nickel-cadmium and nickel metal hydride (NiMH) batteries are mature and suitable for niche applications. Innovation and R&D continues in many other emerging storage technology options. Stages of R&D and timelines and field deployment timing are summarized in Table 17.

Table 17. Emerging Storage Options Research and Development Timelines for Emerging Energy Storage Options

Storage Type	Status/Innovation	Estimated Deployment Timing
Liquid Air Energy Storage Systems	System studies. Low-cost bulk storage. Small demos underway.	2013-2014 first +MW-scale demo.
Non/Low-Fuel CAES	System studies underway to optimize cycle and thermal storage system. Low-fuel and non-fuel CAES for bulk storage.	2015 pilot demonstration of 5-MW system
Underground Pumped Hydro	System studies. New concepts under development.	Under study.
Nano-Supercapacitors	Laboratory testing. High power and energy density; very low cost.	2013-2015
Advanced Flywheels	System studies. Higher energy density.	Under development. 2015.
H_2/Br Flow	Bench-scale testing. Low-cost storage.	2013-2014 pilot demo.
Advanced Lead-Acid Battery	Modules under test. Low cost; high-cycle life.	2013-2015 early field trials.
Novel Chemistries	Bench-scale testing. Very low cost; long-cycle life.	2013-2015 modules for test.
Isothermal CAES	2 MW and 1 MW System Development and Demonstration effort. Non-fuel CAES for distributed storage.	2013 pilot system tests.
Advanced Li-ion Li-air and others	Laboratory/basic science. Lower costs; high energy density.	2015-2020

CHAPTER 3. METHODS AND TOOLS FOR EVALUATING ELECTRICITY STORAGE

3.1 Characteristics of Electricity Storage Systems

There is a fundamental difference in the operational characteristics of traditional generation sources and electricity storage systems operating on the grid. Traditional generation always sends power one way, whereas electricity storage systems require a two-way power flow to function, both charging and discharging states. Other characteristics of storage systems add to this complexity. First, the charging energy could come from a single source or a variety of sources based on the generation portfolio of the grid as a whole; this characteristic could and does change over time. Second, smaller storage could be located anywhere within the grid. While large storage resides on the transmission side, smaller systems could be embedded deep in the T&D network, creating both opportunities and grid integration impacts and concerns. Third, the inherently fast response times measured in fractions of a cycle is its strength and weakness in estimating its value. This characteristic creates a fairly complex computational task for tools and computer models that are required to analyze the financial and technical performance of electricity storage in the grid. Finally, a single storage system could provide multiple services to the grid. Stacking, as this characteristic is called, creates its own set of computational complexities for even robust models.

3.2 Evaluating Electricity Storage Systems

Given these characteristics, a generalized approach for evaluating energy storage includes:

- Assessing storage requirements and value originating from the locational needs of grid operators and planners;
- Avoiding conflation or double-counting of benefits;
- Drawing a distinction between quantifiable and monetizable services and direct and incidental benefits;
- Delaying resource-intensive production simulation analyses until after technically feasible, cost-effective use cases are identified; and
- Delaying deep investigation of policy and regulatory scenarios until after technically sound cost-effectiveness cases are identified and impacts modeled.

The following methodology[63] provides a framework for evaluating electricity storage with the steps described below. Figure 113 provides a visual representation of the evaluation framework.

[63] *Bulk Energy Storage Value and Impact Analysis: Proposed Methodology and Supporting Tool*, EPRI, EPRI ID: 1024288, Palo Alto, CA, December 2012.

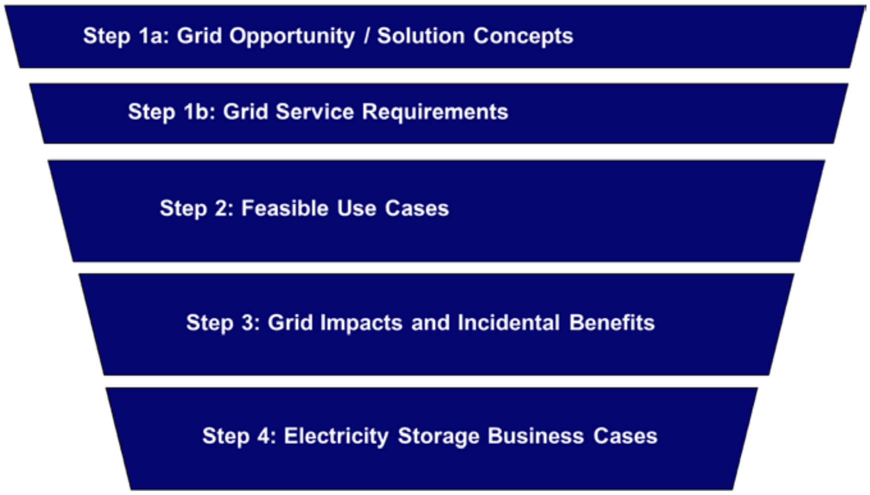

Figure 113. Steps in Electricity Storage Evaluation
(Source: EPRI)

3.2.1 Step 1a: Grid Opportunity/Solution Concepts ("What Electricity Storage Can Do")

Figure 114 illustrates Step 1a.

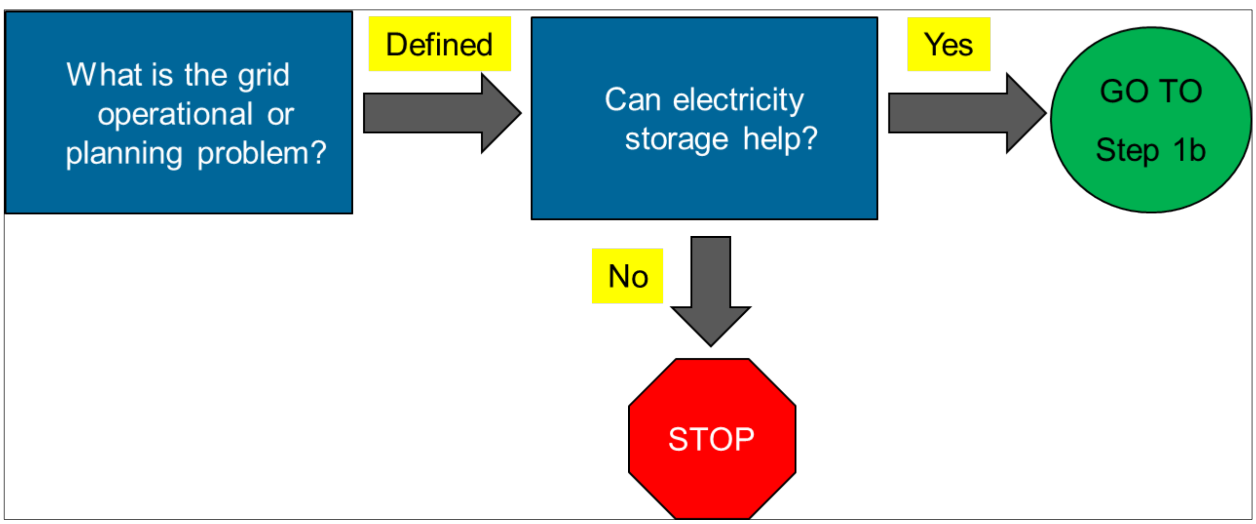

Figure 114. Decision Diagram for Step 1a: Opportunity/Solution Concepts
(Source: EPRI)

3.2.1.1 What Is the Grid Operational or Planning Problem?

Grid operational or planning problems can be anything from a congested transmission line, a sharp load peak, an outage, voltage deviation caused by increased penetration of renewable resources, etc. Some of the services that help relieve those issues are formally categorized in ancillary services and can be procured through markets. Others are site-specific issues that require a unique solution.

3.2.1.2 Can Electricity Storage Help?

Electricity storage fundamentally can store, and later release, energy, effectively moving energy from one time period to another (with losses). When technical and economic opportunities can be created by shifting energy over time periods ranging anywhere from seconds to days (or even seasons), then electricity storage may have value. Additionally, the power electronics in battery systems may have fast response and ramp capability and the ability to operate at non-unity power factors, which can be used to change ac voltage. These characteristics may provide additional opportunities to provide ancillary services, like frequency regulation and voltage support.

The first step of the exploration is to ask the questions: "What is the grid operational or planning issue?" and "Do the unique attributes of storage provide a potential solution?" If the answer is "yes", the second part of the first step is to define the problem and solution with additional technical rigor in Step 1b.

3.2.2 Step 1b: Define Grid Service Requirements (What Must Be Accomplished)

A high-level decision diagram for Step 1b of the methodology is shown in Figure 115.

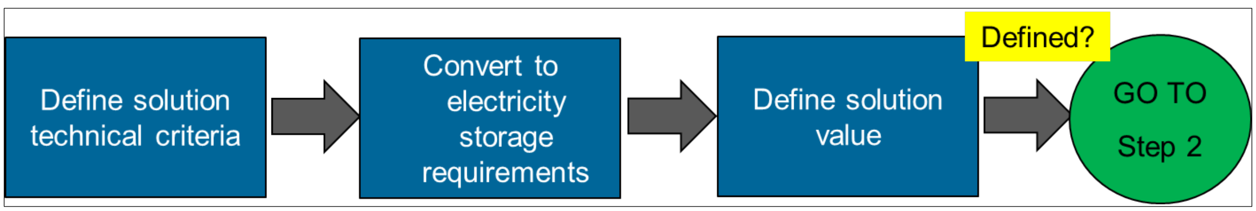

Figure 115. Decision Diagram for Step 1b: Define Grid Service Requirements
(Source: EPRI)

3.2.2.1 Define Solution Technical Criteria

After identifying a conceptual improvement or solution that electricity storage can provide, the next analytical step is to define the grid issue technically and the technical requirements for its resolution. There has historically been some confusion over the terms grid service and application and the terms 'grid service' and 'application' are sometimes used interchangeably. Grid service is used here to indicate that this step considers grid-defined operating requirements and benefits, rather than application of a specific resource.

Convert to Electricity Storage Requirements

Communicating with key stakeholders and decision-makers is critical to determining the appropriate metrics, the minimum operating criteria, and the best available alternative (non-storage) solution to the problem. The technical criteria for an electricity storage-based option can then be determined based on the case-specific information available, including load shapes, market participation rules, generation costs and other time-varying and static characteristics relevant to the grid service under investigation.

3.2.2.2 Define Solution Value

The value of the electricity storage solution can be calculated based on the avoided cost or expected revenue from the chosen grid service. This may require using engineering tools to identify the efficacy of both the electricity storage and the alternative solution to the problem in question. However, the method will be dependent on the grid service under investigation. It may also be considered and documented if either the electricity storage solution or the alternative exceeds the minimum requirements of the service, which may warrant an adjustment in the value of the electricity storage option.

3.2.3 Step 2: Feasible Use Cases

Figure 116 illustrates the generic process for Step 2: Feasible Use Cases.

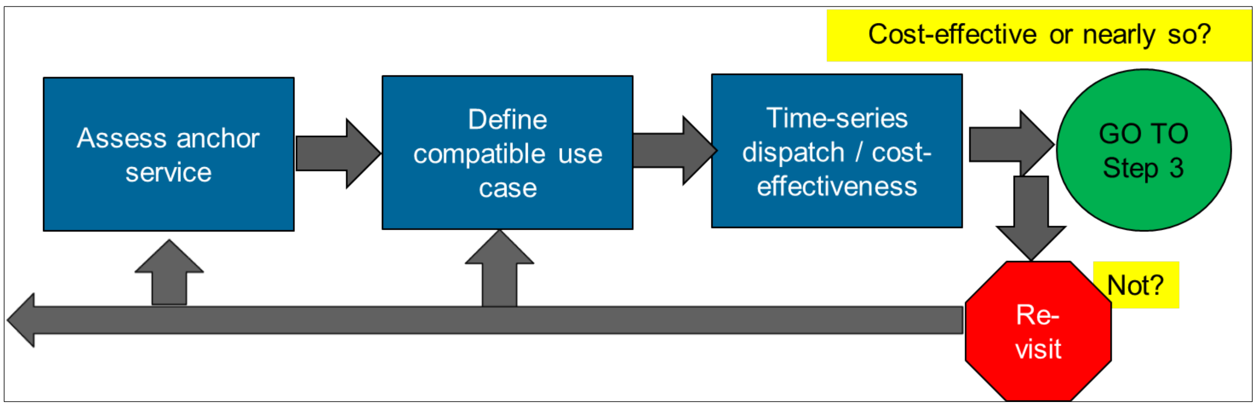

Figure 116. Decision Diagram for Step 2: Feasible Use Cases
(Source: EPRI)

3.2.3.1 Assess Anchor Service

A use case is a technically feasible and monetizable combination of grid services at a particular location. Electricity storage use cases often contain a service of disproportionately high value, which is called anchor service in this Handbook. After requirements have been determined for the anchor grid service in Step 1b, storage technology and configuration options can be investigated. The relative value of the anchor service may then be investigated for different electricity storage options of interest. Assessing the intended anchor service prior to adding additional services may be of value.

In some cases, an anchor service may have location-specific value. For example, the value of providing a distribution upgrade deferral depends on the investment size, load growth rate, and the frequency and duration of peak load events, all of which are unique to each location. In contrast, frequency regulation service may typically be provided from many locations within a region that operates in a synchronous manner (subject to transmission constraints). The electricity storage utilization and value of this anchor service could be estimated with certain operational assumptions or simulated using a time-series simulation.

Typically, a benefit that is 25% to 50% or more of the total storage system cost is a rule of thumb for declaring the potential of a grid service to be an anchor service.

3.2.3.2 Define Compatible Use Case

After the anchor service has been assessed and chosen for further investigation, other compatible grid services, also called secondary services may be considered. Compatibility assessment should occur across multiple dimensions:

- Joint satisfaction of minimum requirements,
- Timing of service (identical, overlapping, or non-overlapping timing), and
- Flexibility of additional services (long-term or short-term commitment?)

3.2.3.3 Joint Satisfaction of Minimum Requirements

The minimum capacity, duration, ramp rate, etc., required to perform the grid services of interest must all be met by the electricity storage system. The secondary services may require longer duration of available storage, or faster response, or another operational parameter that was not considered in the anchor service. If the minimum requirements for the secondary services add significant incremental cost, then the cost of improved electricity storage performance should be reconsidered against the incremental value expected. Identifying additional services for which the initial storage configuration satisfies all minimum requirements is the most beneficial outcome. Failing that, if the upgrade cost of the storage system is lower than the incremental benefit of adding the service, the secondary service may still be considered.

3.2.3.4 Frequency and Duration of Grid Services

The second issue of use-case compatibility is the timing of grid services. The timing and expected operation may coincide identically, overlap, or be non-overlapping in nature. Take, for example, a use case for which electricity storage could be jointly used to shave the transmission transformer peak (transmission upgrade deferral) and the system peak (electric supply capacity). Consider the following three cases: Case 1, in which the transformer and system peaks both occur from 2 p.m. to 6 p.m.; Case 2, in which the transformer peak is from 12 p.m. to 4 p.m. and the system peak is from 2 p.m. to 6 p.m.; and Case 3, in which the transformer peak is from 10 p.m. to 2 a.m. and the system peak is from 2 p.m. to 6 p.m.

In Case 1, shown in Figure 117, the effect of the additional electric supply capacity service to the transmission investment deferral anchor service may be minor, because the storage is performing double duty with a single dispatch, simultaneously unloading a transformer and providing peak generation. (Note that perfect correlation is unlikely between multiple services; this example illustrates an ideal case.)

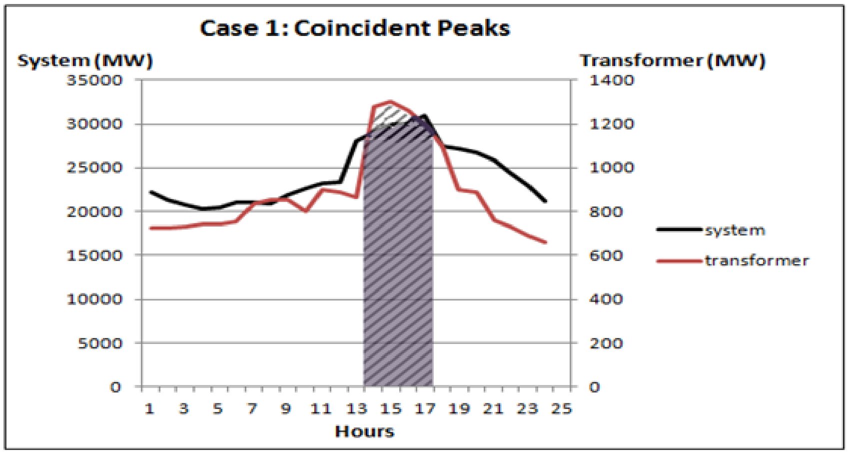

Figure 117. Case 1: Coincident Transformer and System Load Peaks
(Source: EPRI)

In Case 2, shown in Figure 118, the loads are overlapping but not completely coincident (as they were in Case 1). As a result, the cumulative peak that would need to be shaved to satisfy both the transmission investment deferral and system capacity services has now increased from approximately 4 hours to 6 hours, necessitating additional electricity storage duration to accomplish both services.

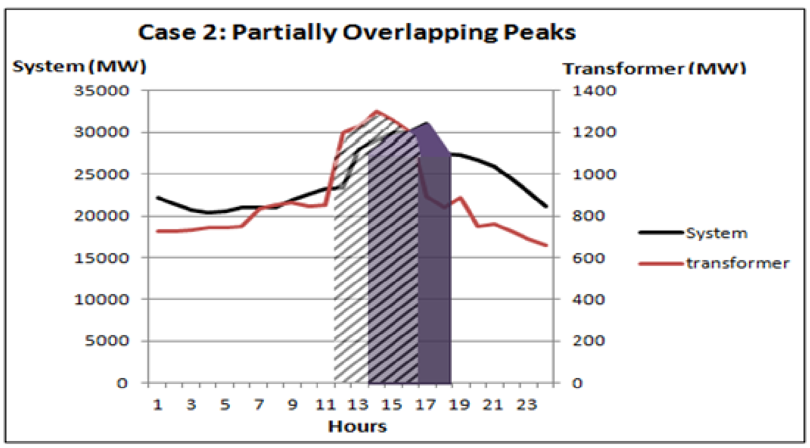

Figure 118. Case 2: Partially Overlapping Transformer and System Load Peaks
(Source: EPRI)

Finally, in Case 3, shown in Figure 119, the peaks are fully non-coincident. As a result, it may be possible to accomplish both services by charging the electricity storage system between the peaks. Therefore, the electricity storage system may not require additional duration, but could require a technology with improved capability for multiple charge-discharge cycles per day. This scenario is possible for situations in which a transformer serves industrial or irrigation loads, which may be timed to coincide with off-peak system hours when these customer time-of-use tariffs charge a low retail price of electricity.

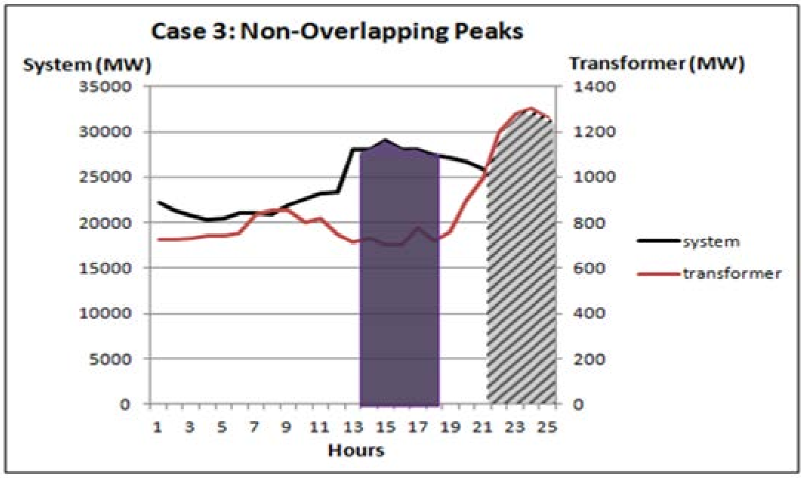

Figure 119. Case 3: Non-overlapping Transformer and System Load Peaks
(Source: EPRI)

3.2.3.5 Hierarchy for Grid Services

Flexibility measured in terms of frequency, duration, and term of commitment is an important consideration for adding secondary grid services to a use case. Certain grid services, such as transmission upgrade deferral, are inflexible. If electricity storage is installed to offset load growth on a transformer, a high degree of availability is required because it is being relied upon in lieu of a capital upgrade. System electric supply capacity may be somewhat more flexible, because there is a greater diversity of resources available to provide capacity within the bulk electricity system. However, capacity payments are often made on a monthly or yearly basis for resource availability during the system peak and penalized when not available. Therefore the flexibility is still relatively low, compared to service that can be committed the day before or even closer to the period of performance. Energy and ancillary service scheduling typically occurs in the day-ahead or real-time, so these services are significantly more flexible and should be easier to add to a use case. When adding two services together, the storage system should always try to meet the operation requirements for the less flexible service and then use the remaining capacity for the more flexible service. Sometimes this approach can lead the value of one service to decline when combined with another service.

When considering secondary grid services, consider the duration of commitment and the control requirements for providing each service, as well as the hierarchy of operation across multiple services. For some technologies, such as flywheels and short-duration batteries, there may not be many choices in what services can be provided. Realistically, due to their short duration, all flywheels and short-duration batteries may be able to provide are regulation services.

After screening for compatibility and value of multi-service use cases, revisit the initial storage system options considered for the anchor service. Optimization between use cases and storage system technology characteristics is currently an iterative process.

3.2.3.6 Time Series Dispatch/Cost-effectiveness

After choosing the use cases including the anchor grid service, compatible secondary services, and other electricity storage systems of interest, an analysis can be designed to quantify the benefits of grid service combinations, locations, and technologies. In some cases, a very simple analysis may be sufficient to screen out those cases with costs that are considerably higher than the benefits. However, due to the complexities of modeling limited energy resources and the importance of time-varying loads and values, more sophisticated tools may be required.

3.2.4 Step 3: Grid Impacts and Incidental Benefits

The summary-level process for Step 3 is displayed in Figure 120.

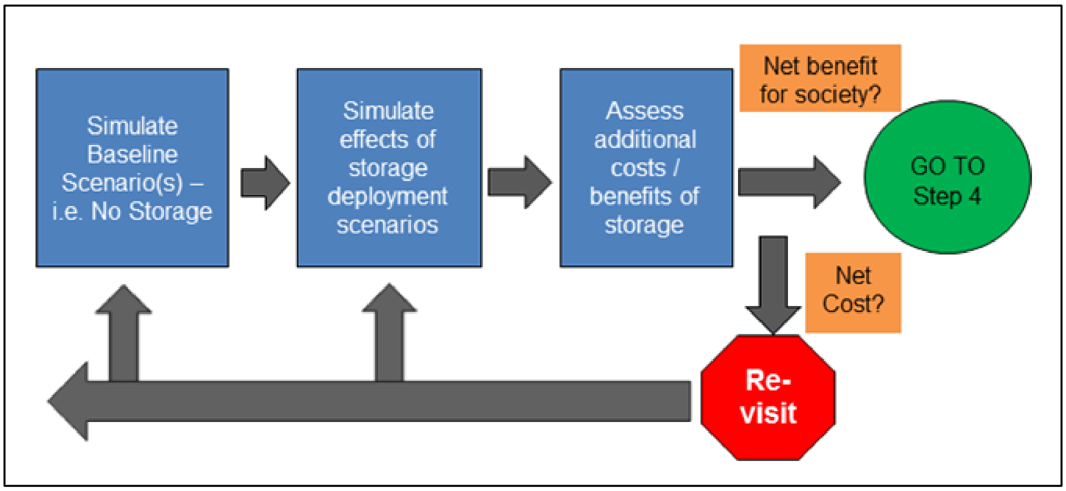

Figure 120. Decision Diagram for Step 3: Grid Impacts and Incidental Benefits
(Source: EPRI)

The purpose of Step 3: Grid Impacts and Incidental Benefits are to determine how the remaining electricity storage deployment scenarios affect system-wide metrics of cost, reliability, and external factors, including:

- Consumer costs,
- System flexibility,
- Transmission asset utilization and generator operation, and
- Environmental impacts, such as greenhouse gas (GHG) emissions.

Step 2 enabled the analyst to assess one or more technically feasible use cases to improve understanding of direct costs and benefits of a storage investment. Steps 1 and 2 may also enable conceptual understanding of how storage may impact the bulk electricity system. The analyst can then form hypotheses to test using production simulation tools, which have the regional perspective required to assess system impacts.

3.2.4.1 Assess Additional Costs/Benefits of Storage

The intent of Step 3 is to investigate impacts and incidental benefits or costs to the electricity system of electricity storage operation. Incidental benefits are not necessarily unintended, but they are not direct benefits explicitly addressed by the operation and control of the storage system. For example, the operation of storage may decrease GHG emissions by providing system capacity during peak demand periods and decreasing the usage of inefficient peaker combustion turbine units. However, if the storage is not directly dispatched with the objective of lower GHG emissions, then this is an incidental benefit. Operation of storage may actually increase the utilization of more carbon-intensive coal-fired base load generators, which could actually increase GHG emissions, but understanding the complex system relationships requires a production simulation. In summary, incidental benefits may result from a combination of the electricity storage system dispatch and other characteristics of the electric system.

If the production simulation shows a significant deviation in energy and AS prices compared to the inputs used in Step 2, the analyst should update the inputs and rerun the price-taker model (such as the EPRI Energy Storage Valuation Tool), as appropriate. Occasionally, the analyst may prefer to go directly to Step 3. For example, if the grid service is regulation, as regulation market is relatively small, a price-taker model may not capture the potentially sizable impact a large electricity storage system could have on a service with low demand (in MW).

3.2.5 Step 4: Electricity Storage Business Cases ("How Storage Can Monetize Benefits")

The simplified process for Step 4: Electricity Storage Business Cases is shown in Figure 121.

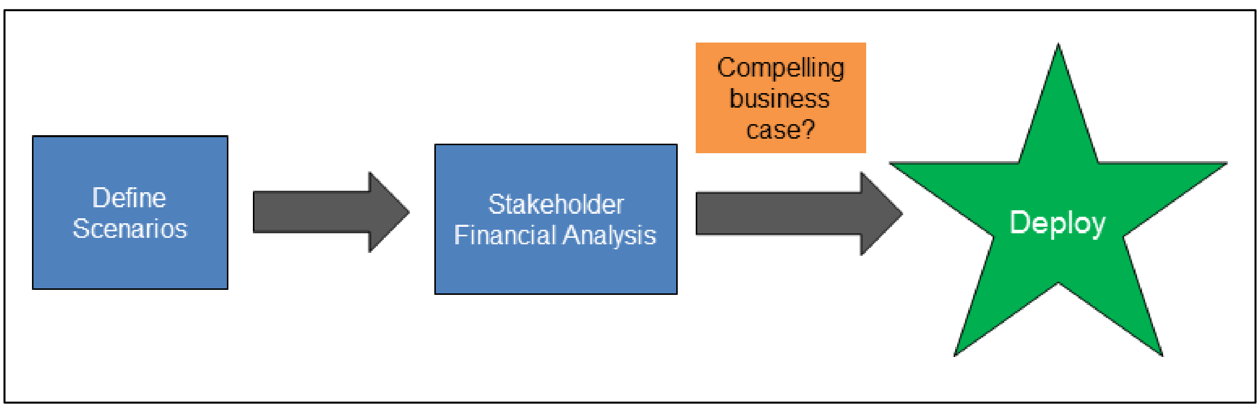

Figure 121. Decision Diagram for Step 4: Electricity Storage Business Cases
(Source: EPRI)

The penultimate phase of assessing electricity storage cost-effectiveness is to investigate real-world business cases. The distinction between this stage of analysis and all previous steps is the inclusion of relevant policy and regulation scenarios, as well as more advanced business-model and financial-analysis considerations. Step 4 is distinct from Steps 2 and 3 in that it focuses on monetization for the energy-storage system owner, rather than considering total value aggregated across all stakeholders.

3.2.5.1 Define Scenarios

Consider the example of a use case involving a transmission investment deferral, energy time-shift (arbitrage), and frequency regulation services. In Steps 2 and 3, the technical capability of the electricity storage system to provide value is evaluated, and the potential value of the electricity storage services is calculated (quantified). However, the avoided cost of the transmission deferral accrues to the transmission system, and the energy and frequency regulation benefits accrue to generation.

Depending on the objectives of the storage valuation analysis, it may be practical to perform Step 4 concurrently with Step 2 to assess both the quantifiable, aggregate value as well as the monetizable value to the storage owner. However, due to the cross-cutting nature of storage and its usefulness to provide a greater diversity of benefits than typical resources, it is important to distinguish "quantifiable value" from "monetizable value." Over longer periods of time, policies and regulations are fluid, so the analyst considers those issues separately to support forward-looking research into electricity storage valuation.

3.2.5.2 Stakeholder Financial Analysis

Once the scenarios of interest have been identified, the analyst can then review the same use case from multiple stakeholder perspectives. Some issues to consider are:

- Business model(s) of the entity,
- Cost of capital for discounting future cash flows,
- Consideration of transaction costs,
- Taxes,
- Risk appetite,
- Permitting, and
- Insurance.

This is only a partial list; many other issues can be considered for case-specific business decisions. Step 4 is the step in which all of the complex realities of investing, building, and operating an emerging technology enter the analysis.

3.3 Modeling Tools

Specific tools that support energy storage evaluations span the spectrum in the level of detail and complexity – from high-level screening to detailed analysis for site- and service-specific needs. Many of these tools have been identified and are listed in Table 18.

Table 18. Analytical Tools for Use in Electricity Storage Cost-Effectiveness Methodology

Category	Resource Portfolio Planning	Production Simulation	Load Flow/ Stability	Dynamics Simulation	Electricity Storage Technology Screening	Electricity Storage Cost-Effectiveness
Focus	Long-term resource and capacity planning needs	Future-year trans. Grid simulation	Near-term T&D grid resource stability/ engineering needs	Short-term variability and load-balancing	Screening storage technology and service combinations	Assessing storage project cost-effectiveness
Goals	Minimize cost and risk of resource portfolio, maximize social welfare	Least-cost unit commitment and economic dispatch with reliability/ transmission constraints to manage minutes to hours variability and uncertainty	Least-cost planning to meet reliability and tolerance thresholds	Manage seconds to minutes variability and uncertainty	Identify promising technology/ services combinations	Maximize expected NPV of storage investment
Scope	Generation, international trading	Generation, Transmission	Transmission or Distribution	Generation	Generation, T&D, Customer	Generation, T&D, Customer
Examples	NESSIE, RETScreen, NEMS, EGEAS EMCAS	PLEXOS, UPLAN, GridView, PROMOD, Ventyx, GE-MAPS PROBE PSO	**Trans:** PSS/E,PSLF, HOMER, **Dist:**CYMDist, Open DSS, GridLab-D VSAT TSAT POM	Kermit FESTIV PSO	ES-Select ESVT ESCT	ESVT (EPRI) ESCT (Navigant)
Core Strengths	Evaluate range of future, regional scenarios and resource portfolios	One-year system dispatch with zonal/nodal model of regional grid, including market price effects	High resolution power flow, Volt/VAR and fault analysis for specific grid configurations	Short-time-scale dispatch for frequency regulation	Scoping analysis of a wide range of technologies and services	Life-cycle financial and cost-benefit analysis from owner/operator and societal perspectives

In addition, Appendix A includes a Review of Selected Tools and describes in more detail tools used for technology screening, storage valuation, production cost modeling, and load flow/stability analysis. The appendix includes a discussion of the scope of these tools, as well as their strengths and limitations for answering the research questions that are currently driving the electric utility industry's interest in energy storage. If necessary, the discussion identifies the analytical gaps facing the industry to assess fully the impact and value of energy storage in different contexts, as well as recent and expected advances in tools and methodologies to address these gaps. Reference is also made to a recently released report "Methodology to Determine the Technical Performance and Value Proposition for Grid-Scale Energy Storage Systems"[64] that quantifies the technical performance required to provide different grid benefits and recommends approaches for estimating the value of grid-scale energy storage systems.

3.3.1 Resource Portfolio Planning

Before embarking on any electricity storage, power generation upgrade or new construction project, an accurate assessment of the options available is crucial to the financial feasibility of the project. A resource portfolio planning simulation has two components. The first component focuses on the specific resources available subject to the operational constraints of the power grid. Inputs to this analysis are typically specific to the geographical location of the proposed project. Power reliability, voltage regulation, demand response and other grid operational components including energy storage option are all variables that can be considered at this stage. In the second component of a resource portfolio planning analysis; these variables are set as constraints and a metric to better evaluate the financial feasibility of the project. Integral to this is the pricing data required to evaluate what an actual financial return will yield relative to the operational constraints of the power grid. One example of a resource planning model would be the analysis of how both energy storage and demand response operations would affect the financial return of the power generation system relative to a very high power reliability constraint. In short, this resource portfolio planning analysis would answer the question; if very high power reliability is required for this specific area, what is the optimal amount of energy storage and demand response needed to maximize profit? This type of analysis is done both locally at the feeder level as well as nationwide at the transmission and generation level for the service area under consideration.

3.3.2 Production Simulation

While resource portfolio planning focuses on the operation of the grid at a higher level, production simulation takes a much more detailed approach focusing on the actual operation of the proposed project at the minute to hourly level and then assessing the financial feasibility relative to other grid resources available at that time. Production simulation takes into account constraints such as load relative to variable generating forecasts, fuel prices, maintenance schedules and other real time operational costs and emission burdens. This also includes daily forecasts of price relative to congestion charges, regulatory fines and other know parameters that may cause daily fluctuations in price. Production simulation can be evaluated at both a "zonal"

[64] *Methodology to determine the technical performance and value proposition for grid-scale energy storage systems : a study for the DOE energy storage systems program*, SAND2012-10639, Sandia National Laboratories, Albuquerque, NM Verne William Loose; Matthew K Donnelly Montana Tech of The University of Montana, Butte, MT; Daniel J Trudnowski Montana Tech of The University of Montana, Butte, MT; Byrne, Raymond Harry; Montana Tech of The University of Montana, Butte, MT, December 2012.

level and a "nodal" level.[65] At the zonal level, production simulation does not account for transmission and distribution constraints between multiple node sets. These nodes are set as input/output parameters such as voltage, current, and power factor, with which the transmission or distribution network is simulated. The dynamics of the system happen only within the transmission or distribution network, otherwise the nodal locations which are typically the generation site are either held constant or change independent of the grid operation. When evaluated at the nodal level, specific input/output parameters are simulated and vary with the operation of the transmission or distribution system. Thus, the fluctuations that occur in the transmission or distribution system are no longer decoupled from the simulation of the rest of the grid components.

3.3.3 Load Flow/Stability

Load flow and stability simulations of the power grid at the transmission and distribution level focus on defined 'what if' scenarios of operations. This analysis is conducted to assess system reliability when sudden disturbances in the grid occur due to any number of conditions including power transfer constraints and loss of generation. It can quantify power quality violations, including voltage and frequency excursions that occur when such upsets happen. Both transmission and distribution modeling software treat power inputs from nodes as relatively constant and then apply a given disturbance scenario. At the transmission level, power input data such as voltage, frequency and current are input to the model for selected busses. A defined scenario, such as a sudden loss of power from a fossil or photovoltaic power plant, is modeled. Some software like HOMER can simulate the interactions between busses down to the 1 minute resolution. The result is an analysis of low and high bus voltage and other voltage deviations. At the distribution level, power flow can be modeled up to the 1 millisecond resolution. Transformers are treated as the nodes to which power flow data is taken and applied. As with a transmission load flow analysis, given 'what if' power scenarios such as a large solar power plant returning power to the grid after being occluded by clouds are applied. From this data, problem areas of the distribution system that experience unacceptable voltage or frequency problems can be identified and identify parts of the grid that can most effectively utilize a storage solution.

3.3.4 Dynamics Simulation

A dynamics simulation tool is used mainly for the simulation of transmission and generation systems. Its primary focus is the identification of frequency drift and power factor problems originating from the transmission system. The main characteristic of this type of tool is the high resolution (on the order of milliseconds) of the time domain, which is crucial in the identification of frequency anomalies.

[65] Survey of Modeling Capabilities and Needs for the Stationary Energy Storage Industry, Navigant Consulting, Inc., May 2014.

3.3.5 Electricity Storage Technology Screening

The purpose of electricity storage technology screening software is to identify possible synergies of energy storage benefit combinations. The Energy Storage Benefits and Market Analysis Handbook[66] lists 15 distinct benefits that can be realized with an energy storage solution. However, not all benefits can be realized simultaneously, especially if the storage solution is being utilized at the same time to capture a different benefit. For example, the avoidance or deferral of a transmission infrastructure upgrade and reduced transmission congestion are two synergistic benefits that a vertically integrated utility may realize. The addition of the benefit of transmission support to this combination may be limited by the use of the storage option for the previous two listed services as well as the systems power and energy characteristics. By exploring all possible combinations of benefits, key stakeholders can maximize their return from a proposed energy storage system by increasing asset utilization. In ES-Select, the more widely recognized electricity storage technology screening software, inputs such as location, main and secondary storage applications and feasibility options for each proposed benefit are aggregated and assessed. Hundreds of possible combinations of storage benefits are chosen at random and presented in use case scenarios with ranges of benefits. The main goal of this analysis is a high level overview of proposed aggregate benefits from a defined and proposed energy storage solution.

3.3.6 Electricity Storage Cost-Effectiveness

A crucial task before implementing a storage cost effectiveness study is the identification of key stakeholders. In a vertically integrated utility the benefits may be straight forward as all monetary gain is received by the one entity that owns the entirety of the infrastructure. However, key stakeholders can range beyond power producers from, technology providers, to project developers, utilities, generators and IPPs, state and federal regulators, end users, ISOs/RTOs, researchers and financers. After identifying the aggregate of benefits that can be realized, properly identifying the key stakeholders may reveal that the benefits may not all aggregate to the same entity. This opens up both possibilities for collaboration between stakeholders as well as complications to ES project implementations. Once benefits are identified, a cost-effectiveness study will help identify the size of the system, the potential return on investment and the optimal performance of the ES system based on the highest rate of return for various dispatching applications.

[66] *Energy Storage Benefits and Market Analysis Handbook*, SAND2004-6177, Sandia National Laboratories, Albuquerque, NM, 2004.

CHAPTER 4. STORAGE SYSTEMS PROCUREMENT AND INSTALLATION

4.1 Using Business Models for Storage Systems

Storage services for the grid can be acquired through several business models, as shown in Figure 122. These business models range from contracting for services only without owning the storage system to outright purchase. The specific option chosen depends on the varying needs and preferences of the owner. This chapter provides broad guidelines for acquiring electricity storage systems using different options.

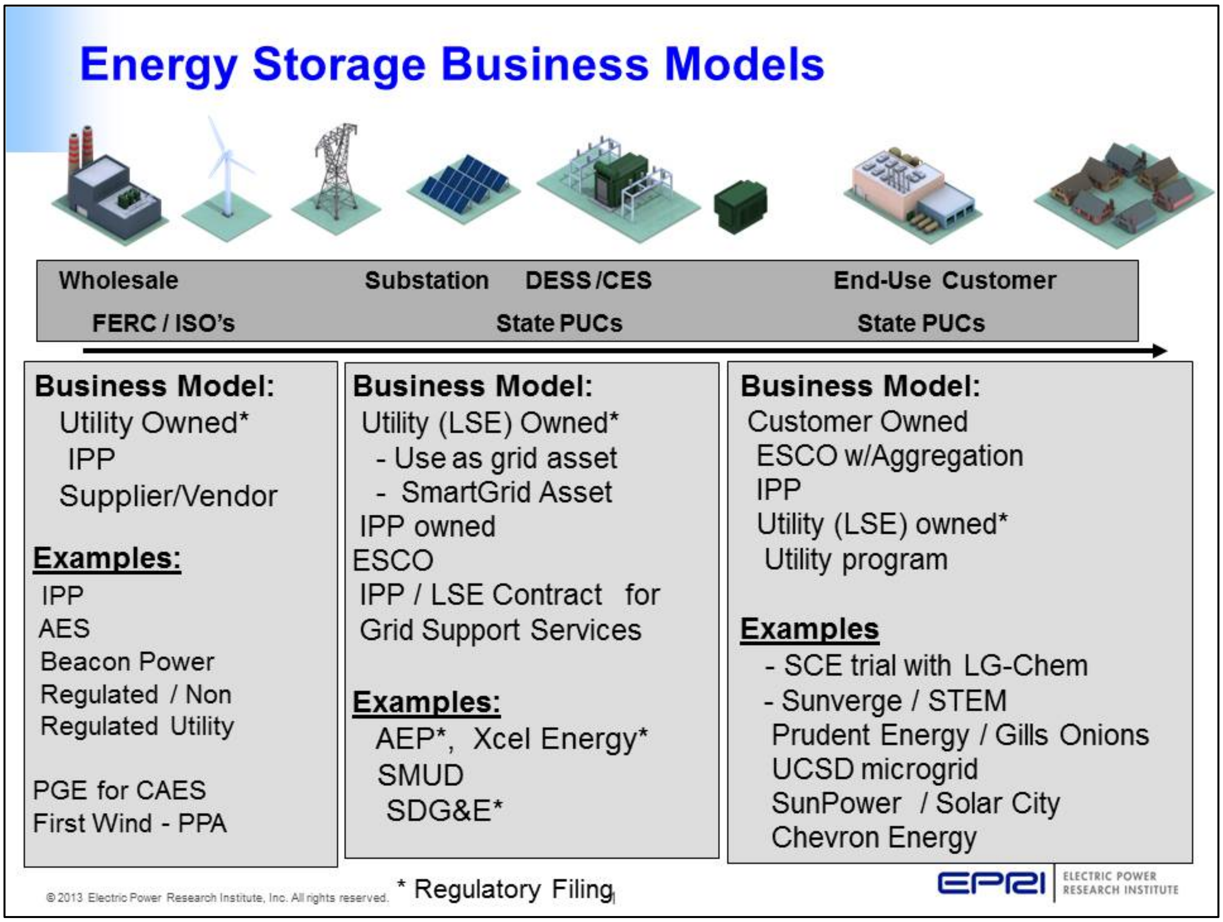

Figure 122. Business Models for Storage Systems
(Source: EPRI)

4.1.1 Third-party Ownership

In this option the storage system is owned, operated, and maintained by a third party who provides specific storage services according to a contractual arrangement. This process is very similar to fossil generating stations' independent power producer agreements. The key terms for fossil plants under such an operating agreement, typically of 20 to 25 years duration, generally include:

- The off taker supplies the fuel, takes the energy, and holds the dispatch rights.
- The seller earns a fixed capacity payment (i.e., $/kW-month) and a variable O&M payment per MWh delivered ($/MWh).
- In return for the capacity payment, the seller assures a certain availability of the plant.
- The seller provides a heat rate guarantee.

The terms of the operating agreement for third-party ownership of a storage facility will be somewhat similar to that of a fossil plant, except the variables for a storage system reflect its unique differences. For example, for a battery storage system, heat rate (MBTU/kWh) is not applicable. It would instead be replaced by a range for round-trip efficiency. The "fuel" would be the cost of off-peak electricity for charging the storage. The complete contract would also include a number of other details such as frequency and number of charge/discharge cycles during the life of the contract, depth of discharge. Similarly, other storage technologies, such as CAES, flywheels and pumped hydro will include operating parameters specific to those technologies that govern their optimal performance during the term of the contractual agreement.

The advantage of third-party ownership is that it shelters the owners – utilities and end-users – from financial and technology risks – both technological obsolescence due to rapid evolution of a particular technology and the inability of the purchased technology to meet projected performance targets. An additional consideration is that the operating costs for a third-party storage plant providing services to an IOU, co-op, municipal utility or end-use customer would be passed through via a bilateral contract.

The third- party ownership model has worked successfully with renewable technologies and in traditional fossil power plant generation projects. It has not, however, been widely adopted by storage technology vendors or investors, especially new entrants to the commercial marketplace who prefer short payback and higher cash flows that outright sales generate.

4.1.2 Outright Purchase and Full Ownership

The alternative option to third-party ownership is full purchase and ownership of a storage system. In this option, the wide range of size and functionality between pumped hydro and CAES technologies, compared to batteries and flywheels, creates a clear distinction between their procurement and installation process. Pumped hydro and CAES are technologies that predominantly provide generation-side services due to their large sizes and long-duration discharge capability. Batteries and flywheels are technologies that predominantly provide grid services that need relatively smaller storage size and shorter duration discharges, as discussed in earlier chapters of the Handbook. Thus the procurement and installation of pumped hydro and CAES is preceded by a far more rigorous analysis to justify their inclusion in the utility system expansion plans, including environmental impact assessments, orders-of-magnitude higher level of civil engineering to develop the sites, and community input in the approval process for the implementation of these projects. This pre-planning takes several years, even before the final procurement of hardware begins. Other reports have detailed the intricacies of navigating the regulatory approval and permitting process for recently proposed pumped hydro and CAES projects.[67] The unique path of each project renders it difficult to identify a common process for procuring and installing these two technologies. Thus the focus of this chapter is on battery and flywheel storage systems, because their procurement and installation lends itself to a more replicable process and is less project-specific.

If the battery or flywheel storage project is solely for a demonstration of the technology for the owning entity, then the procurement process is usually driven by predetermined assumptions of cost, technology preference, and location of the project. On the other hand, if the owning entity is implementing the storage project based on operational needs of the grid, then the choice of storage technology, size, location, and project schedule is governed by the results of analytical tools described in earlier chapters and influenced by system-wide grid and regulatory considerations. In both instances, the owning entity has a choice of procuring the storage system piecemeal, with each subsystem of the storage system acquired separately, or procuring the entire storage system on a turnkey basis.

The current trend in storage system acquisitions has been toward the latter option, which is also facilitated by the commercial availability of several turnkey, modular storage systems with any of the family of battery types or flywheel technology. Turnkey acquisitions relieve the owning entity from specifying each subsystem individually and managing their procurement contracts and installation separately. Before the commercial availability of modular turnkey systems, many of the early utility and cooperative-owned battery storage systems, described in Appendix G: Noteworthy Projects, were acquired on a piecemeal basis and assembled at the project site. The piecemeal approach of building a battery system placed the burden of managing a complex acquisition and construction project on the owning utility. The first modular, turnkey system appeared in the United States in the mid-1990s with the introduction of the Model PM250, a 250 kW battery storage system designed and built by AC Battery (see Figure 123). The PM250 was a factory-assembled, modular, turnkey battery storage system that was delivered to the site in one container-sized package. It demonstrated the advantages of a modular, factory assembled system design over the site-assembled counterparts and laid the foundation for the subsequent availability of today's containerized storage systems.

[67] *Evaluating utility owned electric energy storage systems : a perspective for state electric utility regulators,* Bhatnagar, Dhruv and Loose, Verne, SAND2012-9422, Sandia National Laboratories, Albuquerque, NM, 2012.

Figure 123. First AC Battery PM250 modular battery system installed at Pacific Gas & Electric's Modular Generation Test Facility, San Ramon, CA, in 1993.

Battery and flywheel storage system acquisitions can be managed through a two-step process that consists first of issuing an Request for Information (RFI) followed by a Request for Proposals (RFP), as illustrated in Figure 124. Executing the first step to issue an RFI only requires identifying basic functional requirements of the intended use of the energy storage system and identifying a pool of potential vendors who could supply such a system. The functional requirements described in the RFI can include as many characteristics of the desired system as can be identified at the time the RFI is prepared. These requirements usually include the power and energy size of the system, expected charge/discharge cycles, life expectancy, footprint, proposed location, and other characteristics to provide the vendors with a concept of the storage system. A guide[68] is available that provides information that can guide the initial identification of these system characteristics as shown in Table 19 below.

[68] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits,*PI: Dan Rastler, EPRI, EPRI ID: 1020676. EPRI, Palo Alto, CA, September 2010. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001020676.

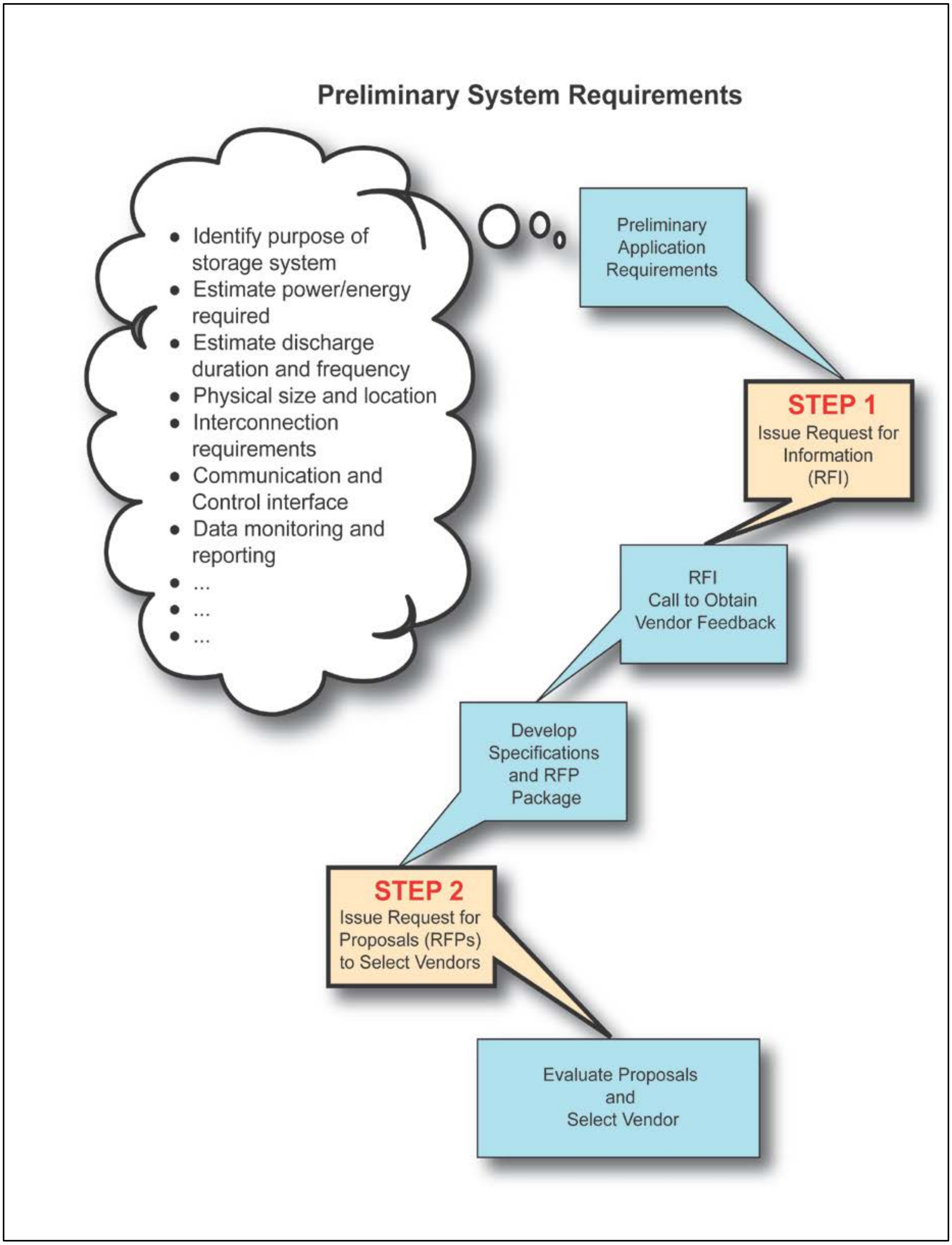

Figure 124. A Process for Storage System Acquisition
(Source: Sandia National Laboratories)

Table 19. Storage System Characteristics for Select Services

Application	Description	Size	Duration	Cycles	Desired Lifetime
Wholesale Energy Services	Arbitrage	10-300 MW	2-10 hr	300-400/yr	15-20 yr
	Ancillary services [2]	See note 2	See Note 2	See Note 2	See Note 2
	Frequency regulation	1-100 MW	15 min	>8000/yr	15 yr
	Spinning reserve	10-100 MW	1-5 hr		20 yr
Renewables Integration	Wind integration: ramp & voltage support	1-10 MW distributed 100-400 MW centralized	15 min	5000/yr 10,000 full energy cycles	20 yr
	Wind integration: off-peak storage	100-400 MW	5-10 hr	300-500/yr	20 yr
	Photovoltaic Integration: time shift, voltage sag, rapid demand support	1-2 MW	15 min-4 hr	>4000	15 yr
Stationary T&D Support	Urban and rural T&D deferral. Also ISO congestion mgt.	10-100 MW	2-6 hr	300-500/yr	15-20 yr
Transportable T&D Support	Urban and rural T&D deferral. Also ISO congestion mgt.	1-10 MW	2-6 hr	300-500/yr	15-20 yr
Distributed Energy Storage Systems (DESS)	Utility-sponsored; on utility side of meter, feeder line, substation. 75-85% ac-ac efficient.	25-200 kW 1-phase 25-75 kW 3-phase Small footprint	2-4 hr	100-150/yr	10-15 yr
C&I Power Quality	Provide solutions to avoid voltage sags and momentary outages.	50-500 kW	<15 min	<50/yr	10 yr
		1000 kW	>15 min		
C&I Power Reliability	Provide UPS bridge to backup power, outage ride-through.	50-1000 kW	4-10 hr	<50/yr	10 yr
C&I Energy Management	Reduce energy costs, increase reliability. Size varies by market segment.	50-1000 kW Small footprint	3-4 hr	400-1500/yr	15 yr
		1 MW	4-6 hr		
Home Energy Management	Efficiency, cost-savings	2-5 kW Small footprint	2-4 hr	150-400/yr	10-15 yr
Home Backup	Reliability	2-5 kW Small footprint	2-4 hr	150-400/yr	10-15 yr

1. Size, duration, and cycle assumptions are based on EPRI's generalized performance specifications and requirements for each application, and are for the purposes of broad comparison only. Data may vary greatly based on specific situations, applications, site selection, business environment, etc.
2. Ancillary services encompass many market functions, such as black start capability and ramping services, that have a wide range of characteristics and requirements.

The RFI does not specify a storage technology type and only includes other desired characteristics of the storage system, unless the owner has a predisposition for a particular storage technology. In the absence of such a preference, it is best to leave the technology selection up to the vendor to ensure that the most suitable storage technology that closely matches the owner's stated requirements is made available.

The complete RFI is then issued to a pool of prospective suppliers with a two-fold purpose. First, it is an opportunity for the vendors to provide feedback to the owners about how they perceive the system requirements and what other pieces of information they need to submit a full proposal when the subsequent RFP is issued. Second, the vendor feedback provides information to refine the system requirements further, based on hardware that is available or could become available within the desired timeframe. This feedback leads to the development of a firm specification for the system that will be part of the RFP issued later in the procurement process. Further, the RFI vendor responses are a good indicator of vendor qualifications to supply a system that meets the owner requirements. It also allows the owners to develop a short list of vendors that will subsequently be included on the RFP requestor list. The smaller pool of vendors will be more likely to have the right technology and qualifications to respond to the subsequent RFP when it is issued. Generally, only one RFI vendor feedback call is needed to move forward on developing the RFP as the next step of the procurement process. A sample RFI used by the Kauai Island Utility Cooperative (KIUC) is provided in Appendix C. *(KIUC has given permission to modify these documents to suit reader's specific needs. Text can be copied and pasted into user-generated documents to develop RFI and RFP packages by the reader.)*

Finally, the advantage of the two-step RFI/RFP process is that an RFI provides a means for a non-binding exchange of information between the owners and vendors that allows them to assess each other's needs and capabilities. This provides the basis for developing a RFP that more closely reflects the requirements of the proposed system matched to the hardware and services that vendors can offer.

Another open source document[69] that can be used as a template for a storage system specification is available from American Electric Power (AEP). This specification for a Community Energy Storage (CES) system was written with input from vendors and other utilities, and its development was facilitated by EPRI.

AEP followed a similar RFI process to formulate a comprehensive specification set that describes the desired functionality of the system, yet leaves the selection of the specific storage technology to the vendor. The specification starts with the simple details and goes on to describe very specific features desired by the utility, including electrical requirements, interconnection, controls, and communications.

4.1.3 Electric Cooperative Approach to Energy Storage Procurement

While IOU and electric co-ops (which are not-for-profit) often have similar needs related to electricity storage, they also have differences in corporate and financial structure, as well as infrastructure and customer demographics. These differences could affect the approach that each takes in regard to capital assets.

One of the major differences between the organizational and financial structures of co-ops and IOUs is that co-ops, unlike IOUs, are split into two categories – distribution co-ops that deliver electricity to its consumers/owners and the generation and transmission (G&T) co-ops that are bulk power providers that own and operate generation assets or purchasing power on the market and sell to the distribution co-op. A key aspect of this relationship is that the G&T is owned by the distribution co-ops it serves. Distribution co-ops have an all-requirements contract with the

[69] American Electric Power, Revision 2.1, http://www.dolantechcenter.com/Focus/DistributedEnergy/docs/CESHubSpecifications_rev2_1.pdf, last accessed on April 25, 2013.

G&T, meaning that special consideration must be made regarding which entity receives the benefits of an energy storage system. For example, a G&T representing distribution co-ops in a regulated market would likely receive significant financial benefits from selling ancillary services like frequency regulation, whereas a distribution co-op likely would not. On the other hand, a distribution co-op may find great value in reducing substation congestion, while a G&T likely does not, depending on the terms of the all-requirements contract. A G&T adds electricity storage for peak-shaving leading to load reduction, which will receive a capacity credit based upon avoided future cost, whereas distribution co-ops will receive a much higher reduction in the cost of their demand charges.

Geographically, electric co-op distribution systems typically have longer distribution feeders and serve areas with much lower customer densities than IOUs. Nationwide, co-ops serve an average of 7.4 consumers per mile of line and collect annual revenue of approximately $15,000 per mile of line versus IOUs, which average 34 customers per mile of line and collect $75,500 per mile. This results in greater emphasis by the co-ops on voltage support and mitigation of feeder congestion. Both IOUs and co-ops are likely to seek energy storage systems to defer substation capacity increases or to address transmission issues.

The not-for-profit structure of co-ops typically limits its ability to take advantage of tax credits and accelerated depreciation on capital investments, whereas IOUs can leverage such tax credits and depreciation to benefit the corporate bottom line. As a result of these differences, an IOU may be more likely to invest directly in ownership of energy storage equipment, while a co-op may lean toward a purchase of energy storage services, rather than outright capital investment. For some co-ops, purchasing services, rather than capital investment, allows taxable entities to own the equipment and realize the tax depreciation benefits—often with a portion of those benefits reflected in a lower cost of services charged to the co-op.

Some of the above-discussed differences in financial drivers for capital investments may be offset by an electric co-op's ability to finance projects at much lower interest rates than IOUs. These lower interest rates would be due to lender perceptions of lower financing risk for co-ops. Electric distribution co-ops are 100-percent debt-financed, with a cost of capital that is 2 to 3 times less than an investor-owned utility, whose financial structure is typically 40 percent equity (with target return on equity of 15 to 20 percent) and 60-percent debt. Thus the electric distribution co-op discount rate is going to be a factor of 2 to 3 times less than for an IOU, which should favor decisions to add energy storage. Consequently electric distribution co-ops may want to own the relatively high capital cost energy storage systems, while an IOU may not. However, capital conservation is important for co-ops, because they are typically smaller organizations with smaller balance sheets. Lenders like the Rural Utilities Service would need to be involved in the decision-making process to permit access to its capital.

4.2 Role of Regulations in Energy Storage Markets, Cost Recovery, and Ownership

Energy storage systems and the services they provide can be sold in regulated and deregulated markets. However, almost all the electrical grid-connected storage services, market opportunities, cost-recovery methods, cost-effectiveness criteria, incentives, and rebates are governed by a well-established regulatory oversight. The rules and regulations that affect storage deployment are enforced by federal and state agencies such as FERC, PUCs, and ISOs. These organizations provide varying oversight and regulation to the industry. ISOs provide oversight of transmission and generation in control areas and FERC regulates interstate transactions and determines rules and tariffs, while PUCs regulate utility management, operations, and capacity acquisition within their State's jurisdiction. Consequently, these rules and regulations impact the growth of the storage industry, because policies can create or inhibit market opportunities for electricity storage and may determine how, and if, they will be compensated.

Figure 125 provides further information into the jurisdictions of the agencies and their influence over the utilization of storage in the grid.

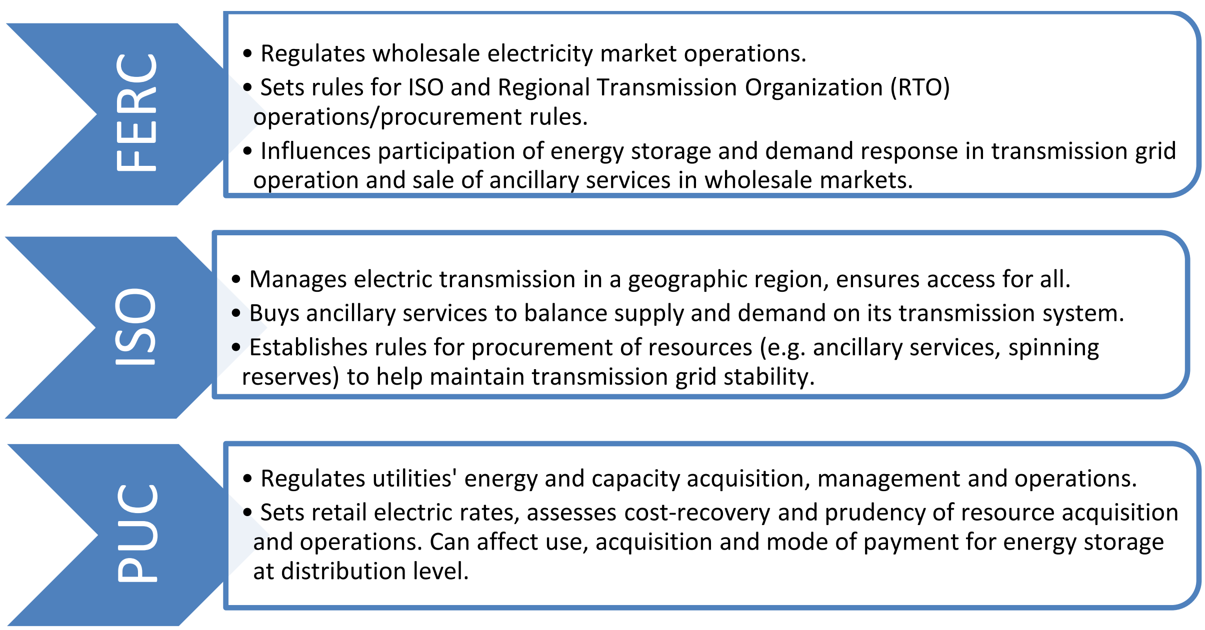

Figure 125. Regulatory Agencies Affecting Electricity Storage Systems

Energy storage industry stakeholders must keep abreast of the myriad activities of regulatory agencies and understand the impacts on energy storage opportunities, pricing, and cost-recovery. Awareness of these rules is important to identify opportunities for energy storage systems. Table 20 presents examples of agency rules that have created opportunities for energy storage deployment. Several of these rules have come about due to proactive involvement in rulemaking by the storage industry associations such as the Electricity Storage Association (ESA), California Energy Storage Alliance (CESA), and storage system vendors. Participation and monitoring rulemaking processes also alerts stakeholders to proceedings that may otherwise lack information on energy storage capabilities and may inadvertently leave it out as a possible option for grid operation.

Table 20. Examples of Regulatory Agency Rules and Their Impacts on Energy

AGENCY	RULE/ACTION	INTENT OF THE RULE OR ACTION	IMPACT
FERC	Rule 755	Directs that ISOs compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the accuracy and speed of responding to the requested level of capacity to rectify frequency.	Fast responding energy storage is paid more because it provides a quicker and more accurate level of power to ISO's set target compared to conventional generation sources.
FERC	Rule 719	Directs ISO/regional transmission organizations (RTOs) to accept bids from demand response resources for certain ancillary services on a basis comparable to other resources.	Opens up possibility for meeting commercial and industrial customers' critical load using storage enabling frequent demand response participation.
FERC	Rule 745	FERC's Market-Based Demand Response (DR) Compensation Rule establishes that electric utilities and retail market operators will be required to pay resources the market price for energy, known as the locational marginal price (LMP), when load reductions will balance the grid's supply and demand as an alternative to a generation resource.	Higher DR rewards may enable use of storage to bid in a larger customer loads for DR participation in a cost effective manner.
FERC	Rule 1000	In an effort to address deficiencies in regional and interregional transmission planning and cost allocations, FERC Order 1000 requires Public Utility Transmission providers to participate in transmission planning at the regional level. These plans must include comprehensive evaluation of transmission solutions in coordination with neighboring region transmission providers to ensure cost effectiveness and must account for public policy requirements. Second, the order requires that the costs of transmission facilities be allocated fairly to estimated beneficiaries. Finally, the order identifies non-incumbent developer requirements.	Because Order 1000 requires alternatives in transmission planning, non-transmission alternatives such as energy storage could potentially see an increase in deployment; and in some instances may provide a more cost-effective solution than other transmission investments.

AGENCY	RULE/ACTION	INTENT OF THE RULE OR ACTION	IMPACT
California Independent System Operator (CAISO)	Modified Rules to Allow Non Generation Resources	Removed resource-type restrictions and reduced minimum rated capacity to 500 kW from 1 MW to provide certain ancillary services. Reduced minimum continuous energy requirement from 2 hours to: Day-Ahead Regulation Up/Down: 60 minutes; Real-Time Regulation Up/Down: 30 minutes; Spin and Non-Spin: 30 minutes. Will allow minimum continuous energy measured from the period that the resource reaches the awarded energy output. Measurement starts once resource reaches awarded energy, not end of 10-minute ramp requirement.	Allows energy storage resources, such as batteries and flywheels, to provide regulation service by fully utilizing their fast-response, fast-ramping capabilities. Allows new storage technologies to provide regulation energy over a continued sustained period that do not have seemingly inexhaustible energy like fossil fuel resources.
CAISO	Flexible Capacity Procurement to Integrate Renewable	CAISO is considering various electricity capacity sources to help manage the steep ups and downs due to wind and solar coming on line under the Renewable Portfolio Standards (RPS) mandate. CAISO defines the characteristics of the acceptable resources to manage steep and sudden ramps.	If superior abilities of energy storage to ramp up quickly in response to needs and reach full capacity are included in the characteristics required, energy storage systems can participate in this market.
CPUC	Energy Storage Rule-making for AB2514	Set up a framework for assessing storage services, cost-effectiveness, and identifying barriers; then possibly setting storage procurement targets if deemed necessary.	May require utilities to procure energy storage to a set target provided cost-effectiveness criteria are met.
CPUC	Self-Generation Incentive Program (SGIP) rules	SGIP offers incentives to customers who produce electricity with wind turbines and fuel cells. Recent revision has made advanced energy storage system eligible for rebate.	Either as stand-alone or combined with other renewable eligible technologies, energy storage initially received $2/watt rebate, declining by 10% in each subsequent years.

4.3 Project Timelines

The larger size of pumped hydro and CAES storage facilities require much longer planning horizons due to the analysis and design activity that precedes their implementation. These planning timeframes typically span seven to ten years or more, depending on public opposition or support for a particular project, the ability to satisfactorily negotiate environmental impact studies, and other approval requirements. The large size and remote location of these projects may also need a new transmission corridor; several years may be required to obtain all the necessary permits and regulatory approvals before it can be constructed (although this activity may be mostly concurrent with storage facility planning).

The relatively smaller battery or flywheel storage projects have been implemented within two to three years from conceptual inception to commissioning. The Fairbanks battery project described earlier, which is representative of a large, site-assembled battery system, took less than four years from its inception to its commissioning date. Smaller storage systems in the 1-MW to 5-MW range have been commissioned in less than two years from initial conception to commissioning. These timeframes are even shorter for the modular containerized systems that can be installed in the field and brought on-line within months after they reach the project site.

A high-level overview of the typical timelines that can be expected for the procurement and installation of a storage technology are shown in Figure 126.

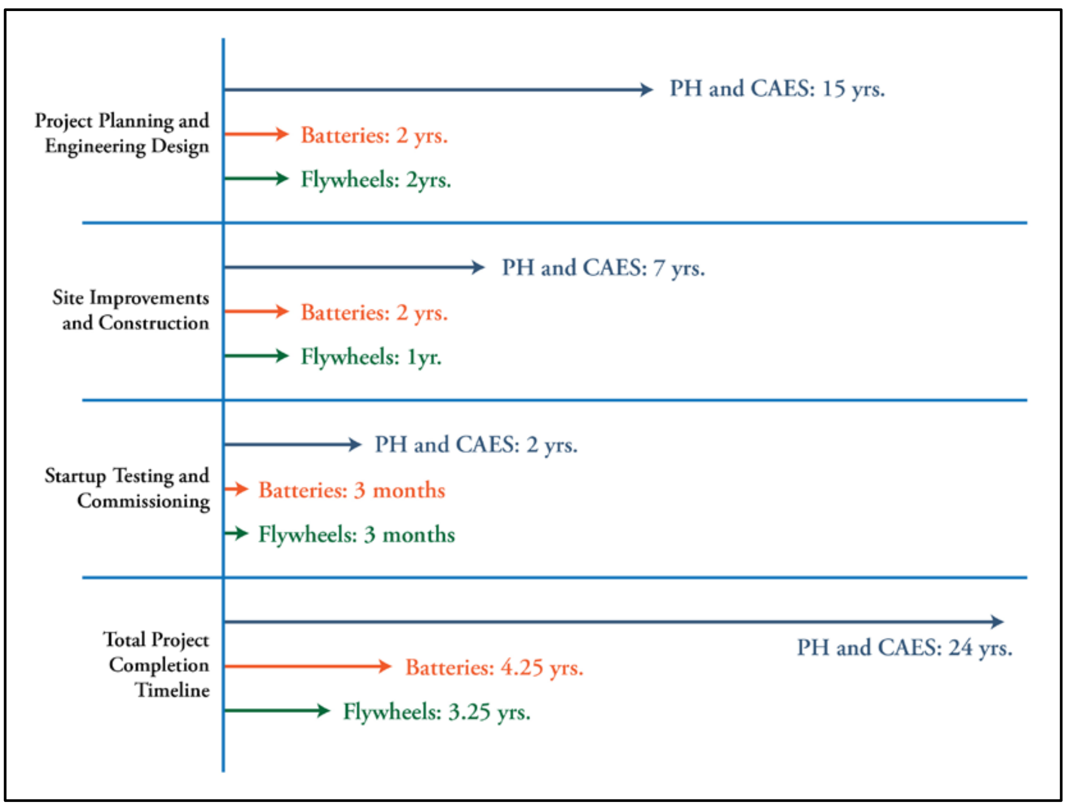

Figure 126. Typical Project Timelines

4.4 RFP or RFQ?

A question frequently asked in the procurement process is whether an RFP or a Request for Quote (RFQ) is more suitable for storage system procurement. An RFP is recommended to acquire a storage system, because the RFP is suitable for a process in which the commodity being acquired has some latitude for variation, as is the case of an energy storage system, whereas an RFQ is used in the instance when the commodity being acquired can be precisely defined and identified. The RFP allows the prospective vendor to propose a system that closely matches the specifications and, in some cases, propose alternatives or add-ons that could offer a superior option. The RFP process generally anticipates that no two proposals will be exactly identical or offer the same commodity. By contrast, the RFQ requires each vendor to quote the exact same commodity, and the quoted price and related support services (if needed) are usually the only criteria for selection of the supplier or vendor.

4.5 Performance Standards and Test Protocols

The duty cycles and other parameters shown for grid services in Table 19 of ELECTRICITY STORAGE SERVICES AND BENEFITS and other places in the Handbook are mostly estimated values derived from computer modeling, limited operational experience with energy storage projects, or the best guess of technical experts in the energy storage community. Using the frequency regulation service as an example, the energy storage system vendors do not offer a standard product for frequency regulation that is designed to exactly match these parameters. Rather, the prevalent industry practice is to offer existing products that most closely match the customer's stated needs, as described in the RFI or RFP. The actual future performance of the storage system, after it is commissioned in the field, is guaranteed through suitable warranties and hard-wired protection features built into the system. Two of these features are hard stops that limit the depth of discharge and/or conservative contingencies on its projected operational life.

While such measures have worked reasonably until now, both the vendors and users recognize an urgent need to codify and standardize both performance requirements and test procedures better to stimulate widespread use of energy storage in the grid. Such standardization lends uniformity to product design and performance and is the hallmark of all mature technologies, but formulating a standard is a lengthy process that requires consensus from a broad base of stakeholders. The DOE Energy Storage Systems (ESS) Program, through the support of the Pacific Northwest National Laboratory (PNNL) and SNL, is facilitating the development of protocols to precede and expedite the formulation of subsequent standards. EPRI is collaborating in this effort with DOE with the objective that, in the near term, these protocols will be used to measure and quantify the performance of energy storage systems in select grid services and subsequently could provide the basis of industry-wide standards. The availability of a suite of uniform, service-specific protocols that include integration criteria and performance metrics will allow storage system vendors, utilities, and other storage users to evaluate the performance of storage technologies on a uniform basis. These protocols will differentiate technologies and products for specific service(s) and provide transparency and uniformity in how performance is measured.

The DOE first-year effort in 2013[70] was focused on frequency regulation and peak shifting with additional applications to follow. The project leads at the two laboratories and EPRI were David Conover at PNNL, David Schoenwald at SNL, and Ben Kaun at EPRI.

4.6 Safety Issues Related to Utility Sited Stationary Battery Installations

The following section provides a guide to addressing overall safety and environmental issues surrounding energy storage systems. Particularly noteworthy issues include the following:

- Many safety and environmental issues are both *site-specific* and *technology-specific*.
- Electricity storage is fundamentally different from other electrical equipment because *it is always energized* and it cannot simply be turned off. This characteristic requires unique procedures on the part of operators, workers, and linemen to ensure adequate safety measures and procedures are in place for installation, commissioning, and operation.
- In many cases, electricity storage contains exotic materials that may require special handling in routine operation, as well as in emergency conditions such as fire, flooding, or earthquakes. The manufacturer *must* produce materials safety recommendations for routine operation as well as information that can be used to inform first responders about proper protocol in dealing with these systems under emergency situations.

4.6.1 Relevant Codes and Standards

Many storage applications are electric utility-owned and/or utility-operated installations. Typically these systems are governed by the National Electrical Safety Code® (NESC®); however, other codes can influence the design based on equipment type, location, and circuit voltage levels. A sampling of relevant codes and standards for a utility-based, advanced lead-acid battery project includes:

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NESC®	National Electrical Safety Code®
NFPA	National Fire Protection Association

[70] *Protocol for Uniformly Measuring and Expressing the Performance of Energy Storage Systems*, PNNL-22010, Bray, K.L., D.R. Conover, M.C.W. Kintner-Meyer, V. Viswanathan, S. Ferreira, D. Rose, and D. Schoenwald, Pacific Northwest National Laboratory, Richland, WA, October 2012. http://www.pnnl.gov/publications/default.asp.

OSHA	Occupational Safety and Health Administration
UL	Underwriters Laboratories

This list includes those codes that are applicable to an advanced lead-acid installation, but is by no means all-inclusive. Project developers should be cognizant of all applicable national and local codes, local interpretations of codes, and any code overlap or grey areas where codes conflict or are silent. For example, NEC may have more clarity on lower voltage systems that utilities typically define as customer side, but if these systems are utility-owned and/or utility-operated, the systems will fall under NESC jurisdiction.

4.6.2 Safety in the Design Process

To enable efficient implementation of the storage project, thoroughly review all codes and standards applicable through the utility's specifications and align these with codes and standards used by the storage manufacturer. Storage systems are a new resource option for utilities and are not traditional components of utility systems. Therefore aligning utility substation, distribution, metering, protection, communication, relay, and potentially transmission system standards with the storage system vendor early in the engineering design and procurement phase is prudent.

During the design process, identify the constructing entities of the project. If on-site construction will be performed by utility or outsourced personnel, identify upfront the capabilities of the assigned entity, the voltage and energy source with which they are qualified, and the codes to which their licenses require adherence. A key example would be a licensed contractor installing a 480V ac system in a utility-owned storage project. The contractor's license typically requires adherence to NEC, but the NESC may have jurisdiction in this case and the contractor may need an exemption to install the NESC-based design.

Project developers should also allow adequate clearances for site installation equipment (cranes, lifts), and easy, code-compliant access for safety and fire suppression-related equipment. Obtaining input from local government safety agency (fire departments, local zoning) is a necessary step in the design, construction, and operational processes that provides emergency responders with clear knowledge of how the storage system operates, the embedded safety systems, the chemical contents of the storage system, and the locations of critical system components at the project site.

Material Safety Data Sheets should be provided by the vendor, and copies should be on file with the local fire department. Project equipment should meet all safety labeling requirements. Local safety officials should be made familiar with and briefed on the emergency response protocols at the site both during construction and upon commissioning, so that they are familiar with the layout and location of the higher risk system components at the project site.

4.6.3 Safety in Operations

The electricity storage systems should have built-in safety features that are integrated into the overall system monitoring and performance architecture. These features and their functionality should be reviewed during the design phase to ensure that they meet the owner requirements and can communicate with the existing Supervisory Control and Data Acquisition (SCADA) system as necessary. The storage system safety alarm should be capable of transmitting to appropriate utility/co-op and emergency response personnel over existing communication channels.

Battery storage systems generally monitor temperatures at multiple locations in the battery string(s) and alert the operator of potential hot spots at critical locations. Additional monitoring with infrared (IR) scanners that sweep the battery stack, system enclosure, or inside the battery building at 5- or 10-minute intervals add a greater level of safety and are strongly recommended for high temperature or more energetic chemistries, such as the lithium family of batteries.

Flow battery systems require added measures for on-site containment of electrolyte spills. Such containment may require construction of dams or berms for large, outdoor storage tanks or design features within the building for smaller, indoor systems. Monitoring and alarm systems should be capable of detecting leaks and initiating appropriate shutdown and alarm features. Emergency response personnel should be involved during the early design phase to ensure that they are adequately trained and prepared for all contingencies.

Similar containment measures are not required of storage systems that do not contain liquid electrolytes or contain electrolytes in insignificant quantities. Examples would be the lithium family or any of the advanced lead-acid batteries. However, secondary containment to hold the water or other chemicals used in extinguishing a fire by the emergency response crews may require containment. This consideration should be addressed with safety personnel and local fire departments early in the project planning phase to ensure compliance with their requirements.

4.6.4 Safety and Environmental Personnel

Dedicated safety and environmental personnel with appropriate training and experience must be involved early in the project development phase to review and develop appropriate safety protocols, review procedures from a safety point of view, and provide guidance in environmental permitting.

After project commissioning, all safety systems should be periodically inspected in accordance with manufacturer specifications and relevant codes and standards. Best-practice safety reviews should be held and any deficiencies noted and corrected.

4.7 Interfacing Storage to the Utility's Existing Communications Network

4.7.1 Front End Communication Control Requirements Definition

As part of the system design, identify the electricity storage system's communication and control needs when interfacing to the utility's existing communication and control architecture. The design should accommodate participant roles and rules, applicable standards (current and emerging), and be compliant with all electric utility interoperability requirements. The architecture and data models along with system requirements should be developed with sufficient specificity to ensure the vendor-supplied equipment works as expected upon commissioning. The contract documents should include specific requirements and specifications to which vendors can successfully respond. A sample specification for a Li-ion transportable battery storage system is shown in Appendix D.

One potential route to successful integration of electricity storage systems and their associated control and communication systems pivots on a requirements analysis, commonly used in systems and software development, that includes determining both functional and non-functional requirements. One possible framework for a requirements analysis can be developed using the IntelliGrid Use Case Template available at EPRI's Smart Grid Resource Center.[71] Functional requirements should present a close examination of the process steps and requirements that emerge from use cases, data, and architecture models and document the discreet requirements that allow the processes in the use cases to operate. In addition, requirements should assign ownership and level of criticality for each requirement.

At this stage detailed logical data models and conceptual architecture models can be developed, along with the corresponding data points list(s) (location of data collection points and requirements). The data models describe the data required and how they interrelate. The architecture model describes physical systems, including electricity storage, metering, source of control signals, and physical layers used for communications. In part, data models address the interoperability requirements, including communication protocols, communication rates, and needs for protocol translation. The data points list should be as inclusive as possible, noting the data capture rate and communication protocol. Many extra slots should be reserved for yet-unidentified data points, as further design development may well lead to a requirement for additional data capture points.

All models must also reflect current and emerging cyber security requirements, including required firewalls, intrusion protection, authentication, account management, access management, access logging, and auditing. The security requirements are especially critical and should reflect the latest cyber security best practices.

[71] EPRI Smart Grid Resource Center: Use Case Repository, http://www.smartgrid.epri.com/Repository/Repository.aspx, last accessed April 25, 2013.

The contract documents should require that a cyber-security plan be developed that addresses and mitigates the critical vulnerabilities inherent in both the hardware and software that comprise the control system and Data Acquisition System (DAS), including sensors, control actuators, control algorithms, communications channels, and so on. The system and its components should be hardened against willful attack or human negligence. In addition the contract documents should require that the Contractor work closely with the Owner to ensure complementary functionality with the Owner's cyber security policy.

As cyber security is an ever-evolving discipline, the following are current (May 2013) suggested resources:

- Guide for Assessing the High-Level Security Requirements in National Institute of Standards and Technology Interagency Report (NISTIR), NISTIR 7628,[72]
- National Institute of Standards and Technology (NIST), NIST Special Publication 800-53,[73] and
- NERC Critical Infrastructure Protection Requirements.[74]
- Other requirements that may need to be addressed, given varying instances, are business continuity, disaster recovery, and regulatory and legal concerns.

Non-functional requirements should present a similar level of detail. Non-functional requirements address such issues as look and feel, usability, performance, operation, maintainability and support, as well as security.

Finally, the functional and non-functional requirements should address software, hardware, and communication interfaces at an adequate level of detail and should be included in a Requirements Document. The Requirements Document should be a product of the effort of correctly identified and active team members, key stakeholders, potential users of the data, and supporting personnel, who clearly communicate expectations and requirements. The Requirements Document is then issued to prospective vendors and provides a vehicle for relaying not only the project objectives and expected features, but also, most importantly, the technical requirements. A sample Requirements Document is provided in Appendix C.

[72] http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf, last accessed April 28, 2013.
[73] http://csrc.nist.gov/publications/PubsSPs.html#800-53, last accessed April 28, 2013.
[74] http://www.nerc.com/page.php?cid=6%7C69, last accessed April 28, 2013.

4.8 Other Implementation Considerations

Project implementation, either through outright purchase or through a services agreement, will require addressing other issues and activities. These will generally include environmental impact studies, interconnection studies, PUC approvals, and siting permits. These other considerations are project-specific and site-specific and cannot be generalized in a simplified manner. However, smaller-sized storage systems are simpler to implement, relative to larger pumped hydro or CAES storage projects. For example, a storage system to provide T&D deferral services will likely be utility-owned and located in an existing substation. In such a case, there may be no need for a building permit or an environmental impact study, especially if this is a modular, containerized storage system. Similarly, a storage system installed to provide ramp support or time-shifting of spilled energy that is a retrofit to an existing renewable system, such as a PV or wind farm, could eliminate the need for a building permit and an environmental impact study because the existing facilities provide umbrella coverage. In such a case, the host utility may determine the need for an interconnection study and other stability analyses.

Warranties for electric storage systems are specific to storage technology, intended service requirements and vendor preferences. Cycling frequency, DOD, and operational lifetimes are the governing parameters for battery technologies; some battery technologies also state operating temperature ranges to be maintained for the warranty to be honored. While attention tends to focus on the storage component of the system, the operating conditions of the other sub-systems, such as the power conversion and control system components, also governs the warranty coverage.

Electricity storage systems that support renewable sources, such as wind and solar, require careful consideration of their warranty terms, especially if there is uncertainty on the variability of the renewable resource. Ramp rates that exceed the design specifications will adversely impact the expected operational life of the battery; field operational data should be reviewed at frequent intervals to flag events outside design ranges. Warranty terms may require renegotiation after a one-year period, if the out-of-bound conditions persist.

Electricity storage is a very flexible resource. The owner/operator may apply the system for grid services unspecified in the original procurement. The warranty terms may require renegotiation if such conditions arise.

4.9 Storage System Test Facilities

The recent emergence of new storage technologies and the growth of commercially available turnkey systems uncovered a strong need for facilities at which system developers and vendors can test their systems to desired performance criteria. As of 2013, at least four such facilities are available in the United States, where storage components or complete systems can be tested under controlled conditions by independent entities. These facilities and their capabilities are summarized in Appendix F.

4.10 Noteworthy Projects

Pumped hydro projects have been built since the early 1900s, whereas large battery projects have a relatively recent history of deployment in the electric grid. The early and current projects have and will continue to break new ground and expand the use of electricity storage into new areas. Noteworthy projects that validated battery technology capabilities in providing grid services and ongoing projects funded in the United States through the 2009–2011 American Recovery and Reinvestment Act (ARRA) are listed in Appendix G.

Appendix G also lists an Internet-based, interactive compendium of energy storage projects worldwide.[75] Although this DOE-supported effort to create a worldwide database is relatively recent, it has become a credible repository of structured information on a variety of projects. The database can be sorted by location, technology type, size, ownership, and current status. New information is added to the database regularly.

4.11 Electricity Storage Trade Associations and Not-for-Profit Conferences

Trade associations, organizations, and not-for-profit conferences that promote electricity storage and provide a venue to network within the energy storage community are listed below.

Electricity Storage Association (ESA)

Originally called the Utility Battery Groups (UBG) until 1996, the ESA is an international trade association working to promote the development, integration, and commercialization of energy storage technologies and systems. The ESA holds an annual meeting to provide the premier industry forum for energy storage leaders.

Website: http://www.electricitystorage.org/about/about_esa

California Energy Storage Alliance (CESA)

CESA is a broad coalition committed to expanding the role of energy storage to promote the growth of renewable energy and a more affordable, clean, and reliable electric power system in California.

Website: http://www.storagealliance.org

[75] DOE International Energy Storage Database, http://www.energystorageexchange.org/projects, last accessed April 28, 2013.

Texas Energy Storage Alliance (TESA)

TESA's membership includes both electrical and thermal energy storage companies in Texas. TESA promotes fair regulatory markets that promote the use of storage in the Electric Reliability Council of Texas (ERCOT) network.

Website: http://texasenergystorage.com

Electrical Energy Storage Applications and Technologies (EESAT)

The EESAT Conference is a biannual event hosted by the DOE's Office of Electricity Delivery and Energy Reliability, SNL, and the ESA. The conference is the premier forum for dissemination, review, and presentation of research and development, demonstrations, and studies conducted around the globe on specific electrical energy storage applications and technologies applied to the electricity grid.

Website: http://www.sandia.gov/eesat/

Electricity storage is also promoted by several overseas organizations. Some of these include:

European Association for Storage of Energy – EASE

Website: http://www.ease-storage.eu/

China Energy Storage Alliance – CNESA

Website: http://www.cnesa.org/indexe.php

India Energy Storage Alliance–- IESA

Website: http://www.indiaesa.info/

GLOSSARY OF TERMS

(A truncated list based on work performed by the Electricity Storage Association)

Term	Acronym	Definition
adiabatic		Of, relating to, or being a reversible thermodynamic process that occurs without gain or loss of heat and without a change in entropy.
alternating current	ac	Flow of electricity whose polarity/voltage changes (alternates) between positive and negative.
amp hours OR ampere hours		Unit of measurement: amount of current that flows over a given amount of time.
ancillary service		Those services which are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice (NERC and FERC order 888-A).
arbitrage		The simultaneous purchase and sale of an asset in order to profit from a difference in the price. It is a trade that profits by exploiting price differences of identical or similar financial instruments, on different markets or in different forms. Arbitrage exists as a result of market inefficiencies; it provides a mechanism to ensure prices do not deviate substantially from fair value for long periods of time.
area control error	ACE	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error (NERC).
asset utilization		The extent to which an asset is used relative to the maximum amount of use that is possible.

automatic generation control	AGC	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction (NERC).
Backup Power		Power source for ride-through of short term power outages.
balancing authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area (BAA), and supports Interconnection frequency in real time (NERC).
balancing authority area	BAA	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load- resource balance within this area (NERC).
base load		The minimum amount of electric power delivered or required over a given period at a constant rate (NERC).
base load generation		Electricity generation designed/intended to operate constantly almost all of the time.
battery		Two or more electric cells connected together electrically. In common usage, the term "battery" is also applied to a single cell, such as a household battery.
black start		Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
C rate		Charge rate that, under ideal conditions, is equal to the energy storage capacity divided by 1 hour. 1 C is the charge rate necessary to charge a battery in one hour.
California Independent System Operator	CAISO	A not-for-profit organization that is the ISO for California which provides open and non-discriminatory access to the bulk of the state's wholesale transmission grid, supported by a competitive energy market and comprehensive infrastructure planning efforts.

California Public Utilities Commission	CPUC	CPUC regulates investor-owned utility companies (IOUs) and sets the rates customers pay for electricity.
capacity		The ability to produce/deploy electricity to be deliver under specified conditions.
capacity factor		A value indicating the average percentage of full capacity used over a given period of time. For example, a generating facility which operates at an average of 70% of its normal full capacity over a measured period has a capacity factor of 0.7 for that period.
capacity firming		To provide energy to fill-in when variable generation output is below the generator's rated power output; done to provide constant power output.
charge		The process of injecting energy to be stored into the electricity storage system.
charge rate		The rate at which electricity storage can be charged.
combined cycle gas turbine	CCGT	Combined cycle gas turbine plants utilize more than one cycle to generate electricity with waste heat used to make steam, generating additional electricity through a steam turbine.
combined heat and power	CHP	Technologies that produce both electricity and steam from a single fuel at a facility located near the consumer (United States Clean Heat and Power Association).
constant-current charge		For batteries; a charging process during which the electric current into the battery is constant. Charging is stopped when the battery is fully charged and constant-voltage charging is used.
constant-voltage charge		For batteries; a charging process during which the voltage applied to a battery's terminals is constant.
contingency		The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element (NERC).
contingency reserve		The provision of capacity deployed by the balancing authority to meet the disturbance control standard (DCS) and other NERC and regional reliability organizations' contingency requirements.

cutoff voltage		Voltage at the end of useful discharge.
cycle		One sequence of storage charging and discharging. Also known as charge-discharge cycle.
cycle life		The number of charge-discharge cycles after which electricity storage becomes inoperable or unusable for a given application.
damping		Any effect that tends to reduce the amplitude (magnitude) of oscillations in a system.
day ahead scheduling reserve	DASR	Supplemental reserves procured and scheduled the day before they will be used.
day-ahead market		A forward market for electric energy, capacity or ancillary services that will be provided or purchased during the next day.
day-ahead price		Price for electricity in a day-ahead market. See day-ahead market.
declining block rate		An energy price structure for high-volume end-users involving prices for energy that decline as the customer's energy use increases. The opposite of inverted block rate.
demand		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer (NERC).
demand charge reduction		Use of distributed or onsite generation or storage and/or use of demand response or energy efficiency to reduce the maximum power draw by electric load.
demand charges		The price paid by a retail electricity user for each unit of power draw on the electric grid. Typically demand charges are applied to the maximum demand during a given month, hence units are $/kW-month.

demand response	DR	Reduction of retail electricity end-users' electric load (power draw) in response to control or price signals. DR resources are deployed and used in lieu of installing/operating peaking generation capacity.
demand side		Of or related to end-user electric demand, often said to be "on the customer side of the meter."
demand side management	DSM	Measures or programs undertaken by a utility designed to influence the level or timing of customer demands for energy in order to optimize the use of available supply resources, in turn allowing suppliers to defer the purchase of additional generating capacity (Cal EPA).
depth of discharge	DOD	The portion of energy discharged from a storage system relative to the amount extractable stored energy.
discharge duration		The amount of time that a storage device can be discharged at the nominal power rating.
dispatch		The process of varying the output from generation on a moment-to-moment basis to meet changing supply requirements.
distributed energy resource	DER	Relatively small and modular electro-technologies that are deployed at the sub-transmission or distribution level.
distributed generation	DG	Small, modular electric generation that is interconnected with the electricity grid at the sub-transmission or distribution level.
economic dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity (NERC).
electric energy time-shift		Storage of energy during times when cost or price is low, for use or sale when the energy's value is high.
electrolyte		For electrochemical batteries; The chemical medium which provides the ion transport mechanism (conduct the electric current) between the positive and negative electrodes (Handbook of Batteries).

end user	The person or entity that uses energy, as distinct from, for example, entities that engage in wholesale energy transactions or purchases made by a landlord or other "distributor."
end-of-discharge voltage	For electrochemical batteries; the voltage of the battery that has been fully discharged.
energy	Energy is the potential of a physical system to perform work.
Electrical energy	The generation or use of electric power by a device over a period of time, expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh) (NERC).
energy density	The amount of energy that a storage system can store per unit volume occupied by the system.
Electric cooperatives	Electric cooperatives are private, not-for-profit businesses governed by their consumers (known as "consumer-members"). Two federal requirements for all co-ops, including electric co-ops, are democratic governance and operation at cost. Specifically, every consumer-member can vote to choose local boards that oversee the co-op, and the co-op must, with few exceptions, return to consumer-members revenue above what is needed for operation. Under this structure, electric co-ops provide economic benefits to their local communities rather than distant stockholders. The majority of co-ops distribute electricity to consumers through low-voltage residential lines that cover more than 75 percent of the nation's land mass. Many of these distribution co-ops, as they're called, have joined to create co-ops that provide them with generation and transmission services (G&T co-ops). Distribution co-ops also buy power from investor-owned utilities (IOUs), public power systems, federal hydropower power marketing administrations (PMAs), and the Tennessee Valley Authority (TVA) (NERCA).

Federal Energy Regulatory Commission	FERC	The Federal Energy Regulatory Commission, or FERC, is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects. The Energy Policy Act of 2005 gave FERC additional responsibilities as outlined in FERC's Top Initiatives and updated Strategic Plan (FERC).
flexible alternating current (ac) transmission system	FACTS	An electronic system and other static equipment that provide control of one or more ac transmission system parameters to enhance controllability and increase power transfer capability (smartgrid.gov).
float charging		A method of maintaining a battery in a charged state by continuous, long-term constant-voltage charging, at a level sufficient to balance its self-discharge rate (Linden's Batteries Handbook).
forced outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure (NERC).
frequency deviation		A change in Interconnection frequency (NERC).
frequency error		The difference between the actual and scheduled frequency (FA – FS) (NERC).
Frequency regulation		The ability of balancing authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control (NERC).
frequency response		(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz) (NERC).

generation dynamic operating benefits		A concept involving more optimal generation fleet operations enabled by use of electricity storage. That is, by adding storage to an electric supply system, the generation.
GigaWatt	GW	a unit of power equal to one billion watts (Merriam-Webster Dictionary).
GigaWatt-hour	GWh	A measure involving one billion watts being generated, transmitted, distributed or used continuously for one hour.
harmonic distortion		Changes to the voltage waveform in an alternating current (ac) system, from a simple sinusoidal waveform to a complex waveform.
heat rate		A measure of generating station thermal efficiency and generally expressed as Btu per net kWh. The heat rate is computed by dividing the total Btu content of the fuel burned (or of heat released from a nuclear reactor) by the resulting net kWh generated (IEPA).
hydroelectric		of or relating to production of electricity by waterpower <constructed a hydroelectric power plant at the dam site> (Merriam-Webster Dictionary).
incremental energy cost		The additional cost of producing and/or transmitting electric energy above some previously determined base cost (IEPA).
independent power producer	IPP	Any entity that owns or operates an electricity generating facility that is not included in an electric utility’s rate base. This term includes, but is not limited to, co-generators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity (NERC).
Institute of Electrical and Electronics Engineers, Inc.	IEEE	IEEE a professional association that is “dedicated to advancing technological innovation and excellence for the benefit of humanity” and to “inspire a global community through IEEE’s highly cited publications, conferences, technology standards, and professional and educational activities”" (IEEE).

integrated resources planning	IRP	A holistic/comprehensive electric resources planning framework that addresses all existing and possible electric supply resources including those owned and controlled by entity doing the planning and other resources that can be provided by other providers. Addressed are supply and demand side alternatives.
islanding		The process of operating an electrical island.
kilowatt-hour	kWh	A unit of work or energy equal to that expended by one kilowatt in one hour or to 3.6 million joules (Merriam-Webster Dictionary).
kinetic energy		Form of energy that an object has by reason of its motion. The kind of motion may be translation (motion along a path from one place to another), rotation about an axis, vibration, or any combination of motions. The total kinetic energy of a body or system is equal to the sum of the kinetic energies resulting from each type of motion. The kinetic energy of an object depends on its mass and velocity. For instance, the amount of kinetic energy KE of an object in translational motion is equal to one-half the product of its mass m and the square of its velocity v, or KE = mv2, provided the speed is low relative to the speed of light. At higher speeds, relativity changes the relationship (Merriam-Webster Dictionary).
levelized cost of energy	LCOE	A convenient summary measure of the overall competiveness of different generating technologies. It represents the per kilowatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle (EIA).
load-serving entity	LSE	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end- use customers (NERC).
locational marginal price	LMP	Value of energy at a specific location as the time that it is delivered (PJM).

marginal cost		The sum that has to be paid the next increment of product of service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity.
market clearing price		The price at which supply equals demand for the Day-ahead or hour-ahead markets (IEPA).
megawatt	MW	A unit of power equal to one million watts (Merriam-Webster Dictionary).
megawatt-hour	MWh	One thousand kilowatt-hours or one million-watt hours.
microgrid		A microgrid is an electrical system that includes multiple loads and distributed energy resources that can be operated in parallel with the broader utility grid or as an electrical island (smartgrid.gov).
Midwest Independent Transmission System Operator, Inc.	MISO	An Independent System Operator (ISO) and Regional Transmission Organization (RTO) providing open-access transmission service and which monitors the high voltage transmission system throughout the Midwest United States and Manitoba, Canada (MISO).
Midwest Reliability Organization	MRO	A non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of the United States and Canada. MRO is one of eight regional entities in North America operating under authority from regulators in the United States and Canada through a delegation agreement with NERC. MRO's primary focus is developing and ensuring compliance with regional and international standards and performing assessments of the grid's ability to meet the demands for electricity (MRO).
municipal electric utility	muni	A power utility system owned and operated by a local jurisdiction (IEPA).
N-1 Contingency		Exogenous Event involving Loss of a major line or transformer (EPRI).
N-2 Contingency		Exogenous Event involving Coincident loss of two major lines or transformers (EPRI).

National Association of Regulatory Utility Commissioners	NARUC	Founded in 1889, the National Association of Regulatory Utility Commissioners (NARUC) is a non-profit organization dedicated to representing the State public service commissions who regulate the utilities that provide essential services such as energy, telecommunications, water, and transportation (NARUC).
net metering		Net metering enables customers to use their own generation from on-site renewable energy systems to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand, enabling customers to receive retail prices for the excess electricity they generate (DOE/EERE).
net scheduled interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time (NERC).
New York Independent System Operator	NYISO	The not-for-profit independent system operator (ISO) for the state of New York. It operates the high-voltage transmission network, administers and monitors the wholesale electricity markets, and plans for the state's energy future. It is responsible for the reliable operation of New York's nearly 11,000 miles of high-voltage transmission and the dispatch of over 500 electric power generators (NYISO).
New York State Energy Development Authority	NYSERDA	A public benefit corporation created in 1975 through the reconstitution of the New York State Atomic and Space Development Authority. NYSERDA's earliest efforts focused solely on research and development with the goal of reducing the State's petroleum consumption. Today, NYSERDA's aim is to help New York meet its energy goals: reducing energy consumption, promoting the use of renewable energy sources, and protecting the environment (NYSERDA).

Non-spinning Reserve		That generating reserve not connected to the system but capable of serving demand within a specified time. Interruptible load that can be removed from the system in a specified time (smartgrid.gov).
North American Electric Reliability Corporation	NERC	NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada. NERC is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical and efficient practices. More specifically; NERC has authority to enforce reliability standards with all users, owners, and operators of the bulk power system in the United States, and makes compliance with those standards mandatory and enforceable (NERC).
Northeast Power Coordinating Council, Inc.	NPCC	A not-for-profit corporation responsible for promoting and improving the reliability of the international, interconnected bulk power system in Northeastern North America (NPCC).
off-peak		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand (NERC).
on-peak		Times when demand for electricity is highest (aka peak demand). Typically on-peak times occur during weekdays during the hottest summer months, when normal demand is high and when air conditioning is operating. Similarly, in some areas on-peak times may be in the winter when high normal demand is combined with high heating-related power use (NERC).

operating reserve	The capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserves (NERC).
operating reserve- spinning	The portion of Operating Reserve consisting of: Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or Load fully removable from the system within the Disturbance Recovery Period allowing the contingency event (NERC).
operating reserve- supplemental	The portion of Operating Reserve consisting of: Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or Load fully removable from the system within the Disturbance Recovery Period following the contingency event (NERC)
Open Access Transmission Tariff	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves (NERC).
peaker	An electric supply resource, typically a combustion turbine generator or reciprocating engine, whose primary purpose is to generate electricity when peak demand occurs.

Peak demand		The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year)., The highest instantaneous demand within the Balancing Authority Area (smartgrid.gov).
performance based ratemaking	PBR	Utility revenue is based upon established performance objectives rather than cost.
performance-based regulation		A regulatory approach that focuses on desired, measurable outcomes, rather than prescriptive processes, techniques, or procedures. Performance-based regulation leads to defined results without specific direction regarding how those results are to be obtained (NRC).
phasor measurement unit (synchrophasors)	PMU	Phasor Measurement Units (PMUs) calculate voltage and current phasors based on digital sampling of alternating current (AC) waveforms and a precise time signal provided by a GPS clock. A PMU provides output data in a standard protocol at rates of 30 or more samples/second, communicating to remote locations. The time-stamped measurements allow collected synchrophasor data to be accurately compared to time synchronized conditions at distant locations. Devices with PMU capability are also considered PMUs (smartgrid.gov).
PJM Interconnection	PJM	PJM Interconnection (PJM) is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM manages the high-voltage electric grid and the wholesale electricity market that serves 13 states and the District of Colombia (PJM).
planned outage		The removal of the unit from service to perform work on specific components that is scheduled "well in advance" and has a predetermined duration (IEEE).
Power		The rate at which energy is transferred, used, or transformed.

plug-in hybrid electric vehicle	PHEV	A hybrid electric vehicle that can be connected to the electric grid for charging and/or to supply stored electricity to the grid.
power factor		the ratio of real power to apparent power
primary cell or battery		A cell or battery that is not designed to be recharged and is discarded after delivering its charge.
Public Service Commission or Public Utility Commission	PSC/PUC	An agency that regulates the rates and services of utilities at the State level.
ramp rate		(Schedule) The rate, expressed in megawatts per minute at which the interchange schedule is attained during the ramp period." (Generator) The rate, expressed in megawatts per minute, that a generator changes it output.
reactive power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovolt amp-reactive (kVARs) or Megavolt amp-reactive (MVARs).
real power		The portion of electricity that supplies energy to the load.
regional transmission organization/Independent System Operator	RTO	A federally regulated independent entity responsible for the management and control of the electric transmission grid within a region. RTO's were formed by FERC Order Number 2000. ISO's are similar to RTO's but control smaller geographic regions. ISO's were formed by FERC Order Number 888/889.
regulating reserve		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
regulation service		The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority.

response rate		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
revenue requirement		The amount of revenue required to cover all utility costs -- including those related to electric supply, transmission, distribution and customer service -- including capital-related expenditures, operating expenses, taxes, interest on and return of debt, and, if applicable, the authorized rate of return on and return of stockholder equity.
round trip efficiency		The ratio of the output of an electricity storage system to the input required to restore it to the initial state of charge under specified conditions.
secondary battery		A galvanic battery which after discharge may be restored to its charged state by passing an electric current through it in a direction opposite to that of discharge.
self-discharge		The loss of useful capacity of a storage system due to internal losses such as internal chemical action in a battery, frictional losses in a flywheel or air lost from the storage reservoir in a CAES system.
state of charge	SOC	The degree to which storage is charged relative to the maximum possible amount of energy that can be stored by the system, typically expressed as a percentage.
supplemental operating reserve		The portion of operating reserve consisting of: 1. Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the disturbance recovery period following the contingency event; or 2. Load that is fully removable from the system within the disturbance recovery period following the contingency event. See also operating reserve and synchronized operating reserve.

synchronized operating reserve		The portion of operating reserve consisting of: 1. Generation that is synchronized with the grid and that is fully available to serve load within the disturbance recovery period following the contingency event; or 2. Load fully removable from the system within the disturbance recovery period following the contingency event. This type of reserve capacity is often said to be "spinning" because rotating machinery associated with generation must indeed be spinning to be synchronized with the grid. See also operating reserve and supplemental operating reserve.
synchronized reserve service		One of six ancillary services specified by the FERC under Order 888.
time of use (energy prices)	TOU	Price for electric energy that is specific to the time (season, day of week, time-of-day) when the energy is purchased.
transmission		An interconnected group of lines and associate equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems (NERC).
transmission and distribution upgrade deferral		Use of a power source and/or demand management to reduce loading on a specific portion of the T&D system, to delay the need to upgrade the T&D system to accommodate load growth.
trickle charging		Electrochemical cell or battery charging involving a continuous or an intermittent constant-current supply which keeps the cell/battery fully charged while the cell/battery is not being used (discharged).

uninterruptible power supply	UPS	A source of backup power – sometimes including batteries and increasingly flywheel energy storage – that is used to ensure continuous availability of power in the event of an interruption of service. UPSs range from units for individual equipment items to those for entire facilities. Storage-only UPSs typically have enough energy to operate for a few to several minutes. UPSs may also incorporate generation-based capacity which provides power over extended periods of time.
unplanned outage		An interruption of electric generation, transmission or distribution operation which is not scheduled.
upgrade deferral		Delay the need to replace or enhance equipment within the grid, usually by using a power source or load management to reduce the peak load served by the equipment to below the equipment's rated power. See also life extension and transmission and distribution upgrade deferral.
use case		A specific deployment of a storage system for one or more applications and/or one or more benefits.
Volt/VAR Control		In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power in an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (1).
voltage support		Voltage support is the supplying of reactive power into and out of the system for maintaining desired voltage.

LIST OF APPENDICES

APPENDIX A: REVIEW OF SELECTED TOOLS

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REVIEW OF SELECTED TOOLS

Table A-1 shows the main categories of energy storage simulation tools. Energy storage tools often have overlaps in applications and therefore main applications of a tools are represented with a black dot and secondary applications are represented with an open dot.

Table A-1. Summary Matrix of Energy Storage Evaluation Tools by Functionality

ES Models and Tools							
Modeling Tool	Resource Portfolio Planning	Production Simulation	Load Flow/ Stability	Dynamic Simulation	Electricity Storage Technology Screening	Electricity Storage Cost-Effectivness	Grid Operations and Control
Demand Side Management Option Risk Evaluator (DSMore)	●					○	
Electric Generation Expansion Analysis System (EGEAS)	●					○	
Electricity Market Complex Adaptive System (EMCAS)	●	○				○	
Integrated Planning Model (IPM)	○					○	
North American Electricity and Environment Model (NEEM)	●					○	
National Energy Modeling System (NEMS)	●					○	
Portfolio Optimization Model (POM)	●					○	
Regional Energy Deployment System (ReEDS) Model	●					○	
Aurora XMP (Aurora)	○					●	
Day-Ahead Locational Market Clearing Prices Analyzer (DAYZER)	○			●		●	
Flexible Energy Scheduling Tool for Integration of Variable Generation (FESTIV)				●		●	
GE Multi-Area Production Simulation Software (GE MAPS)	○	●				○	
GridView	○	●				○	
HOMER	○	●	●			○	
PLEXOS		●	●			○	
Portfolio Ownership and Bid Evaluation (PROBE)		●	○			○	
PROMOD IV		●	●			○	
REFlex				○	○		
UPLAN Network Power Model (NPM)	●	●	●			○	
ETAP Grid: Transmission Software		●	●				
GE Concordia Power Systems Load Flow Software (PSLF)		●	●	○			
GE Power System Dynamic Simulation (PSDS)				●			
Integrated Dispatchable Resource Optimization Portfolio (IDROP)		●	●	○		○	
Power System Simulator for Engineering (PSS/E)		●	●				
PowerFlow & Short Circuit Assessment Tool (PSAT)		●	○	○			
PowerWorld Simulator (PWS)		●	●				
TRANZER		○	○				
Electricity Distribution Grid Evaluator (EDGE) Model	●	●				●	
ES-Grid	●	○				●	
ETAP Grid: Distribution Software			●	●			
GridLab-D		○	●				
KERMIT			●	●		○	
LoadSEER	○	●				●	
Open Distribution System Simulator (OpenDSS)		●	●	●			
SynerGEE		●					
WindMil			●				
Alstom Distribution Management System - Demand Response Distributed Generation (DMS – DRDG)							●
Decentralized Energy Management System							●
Distribution System Operations Solution							●
GE Distribution Management System							●
Oracle Distribution Management System (DMS)							●
OSI Spectra Distribution Management Systems							●
Advance 2 Control	○					○	●
Battery XT						○	●
BOS4						○	●
Core Operating System						●	●
Cost Performance for Redox Technologies						●	●
DynaTran						●	
Energy Operating System							●
Energy Storage Computational Tool					●	●	
Energy Storage Valuation Tool					●	●	
Energy System Model					○		
ES Simulator					●	●	
ES Select					●	●	
Frequency Regulation Performance Model				●		●	
GridStore	○					●	
Joule.System						●	●
Market Revenue Optimization Model for Behind-the-Meter Storage Projects						●	
Market Revenue Optimization Model for Grid-Connected Storage Projects						●	
Microgrid Optimizer						●	
OnCommand							●
PowerScope						●	●
1E Storage Integrator							●
WindStore						●	

● tool is well suited for the application

○ tool has some functionality for the application

A.1 Technology Screening: ES-Select

The ES-Select™ Tool aims to improve the understanding of different electrical energy storage technologies and assess the feasibility for intended applications in a simple, visually comparative form. This tool treats the uncertainties in technical and financial parameters as statistical distributions.

ES-Select™ was created by KEMA in collaboration with Sandia National Laboratories. It is licensed for public use.

A sample screen capture from ES-Select™ Tool is shown in Figure A-1.

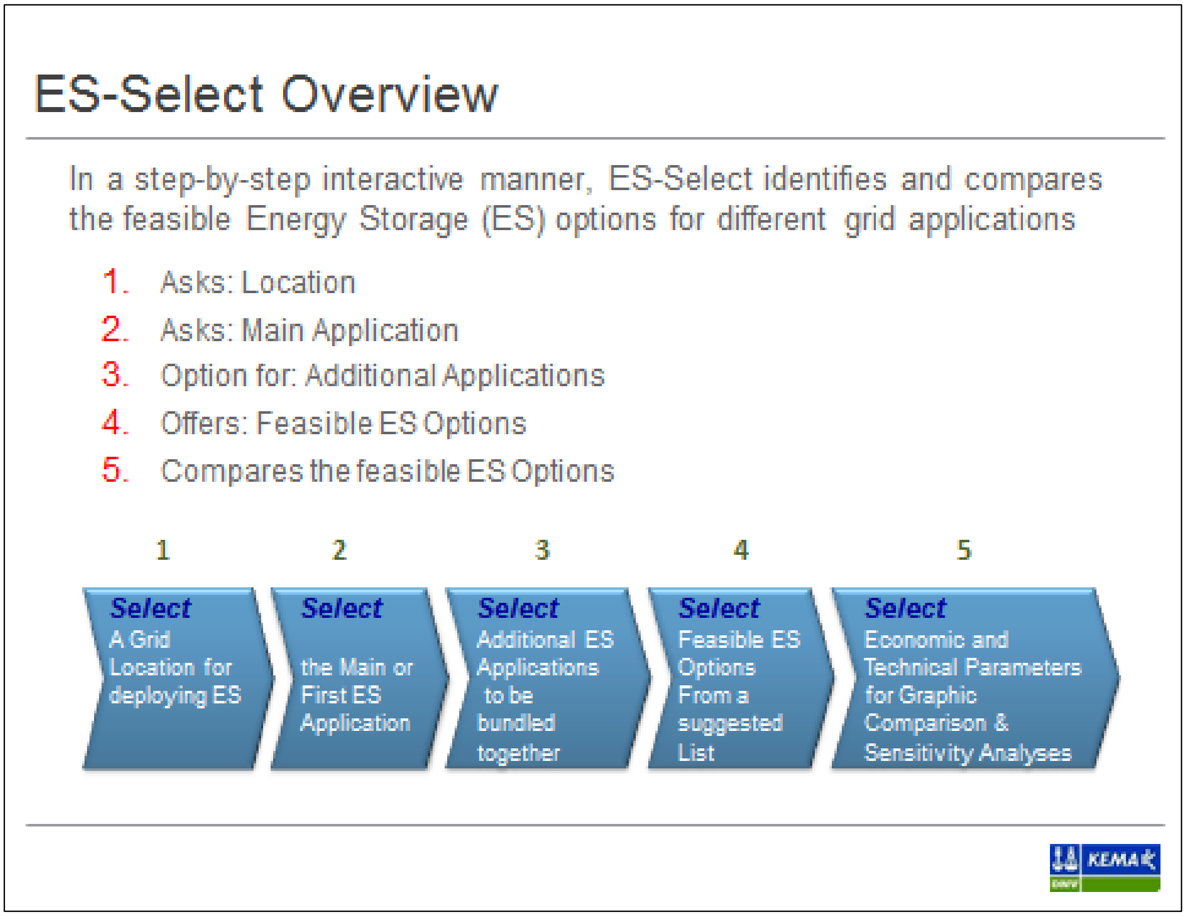

Figure A-1. ES-Select Overview

ES-Select is designed to work with the uncertainties of storage and applications characteristics, costs, and benefits and provides answers in reasonable ranges. It applies the Monte Carlo analysis to choose randomly hundreds of possible values within the provided ranges of input parameters to calculate the range of possible answers. In this educational/screening tool, simplicity is more important than precision. This decision support tool is made for the initial screening purpose. Most facts are still unknown to the user, but some decisions must be made based on what is known at this point.

ES-Select assumes the most likely values for all project parameters that it needs, allowing the user to overwrite these values if more accurate information is available. The objective behind this design principle is to make the tool useful to both a novice user, who needs to be educated on reasonable values, as well as an experienced user, who knows exactly what the problem is and has all relevant data ready to enter.

The main outputs of ES-Select are expected ranges of cash flow, present value, and payback for all storage options for selected applications. The tool also helps users plot all financial and physical parameters of applications and storage options for comparative studies. Figure A-2 (below) shows an overview of ES-Select design and functionality.

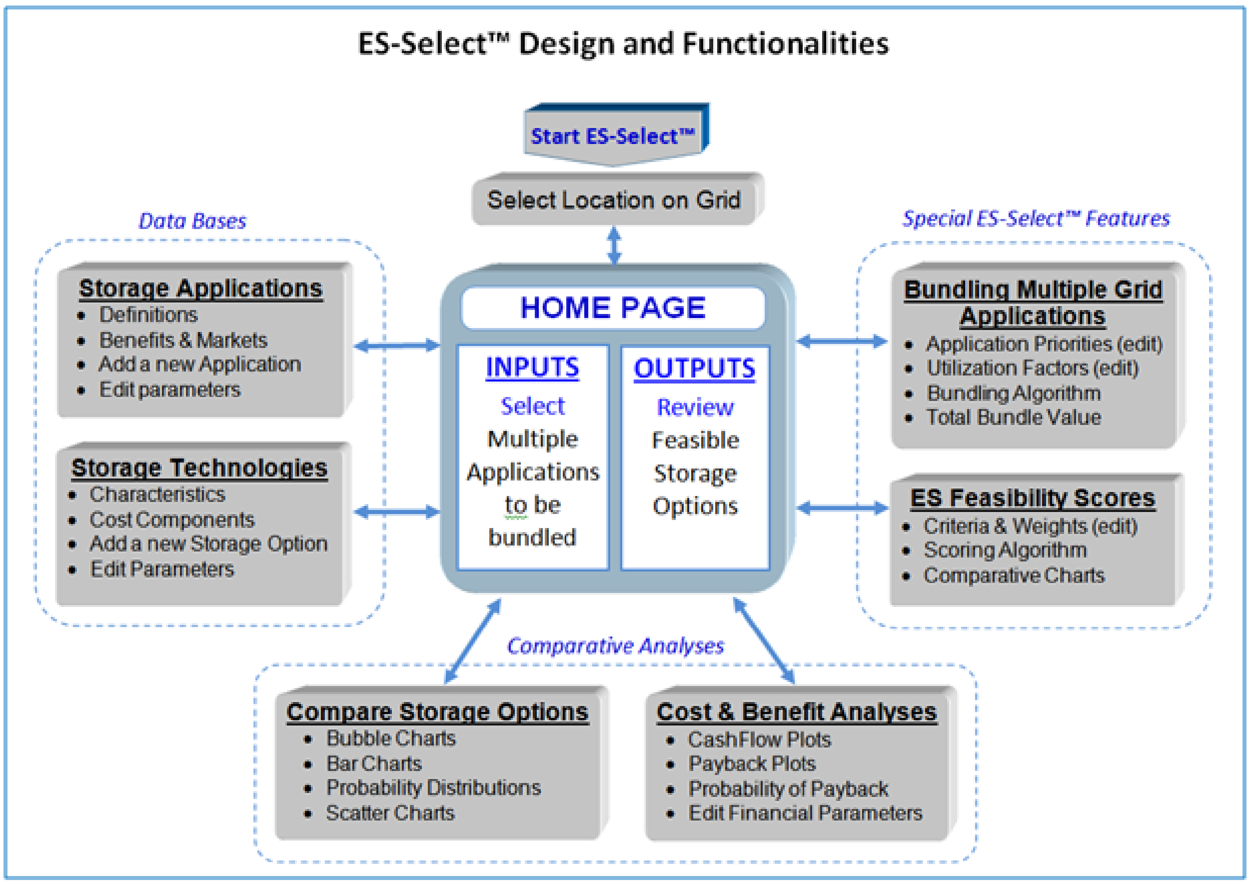

Figure A-2. ES-Select Design and Functionalities

ES-Select helps decision makers:

- To understand and compare accurately the costs and benefits of various energy storage technologies,
- To identify and compare applicable electricity storage parameters, and
- To develop a preliminary business case for specific services and/or use cases.

ES-Select performs the following key functions:

- Allows selection of a grid location to deploy energy storage;
- Allows selection of two or more grid services and/or use cases to be bundled to increase the total value of an electricity storage system;
- Recommends feasible electricity storage options for the selected grid services and/or use cases;
- Considers the uncertainty in cost and benefit numbers, as well as other factors, and does calculations based on a probabilistic distribution comparing the different energy storage options; and
- Provides distributions of economic and technical parameters for graphic comparison and sensitivity analyses.

Although ES-Select has many strong capabilities, it is only the starting point toward a comprehensive analysis of an energy storage system. In its current form, it does not allow:

- Specification of system location in the United States (or world) and the associated parameters (market environment, etc.),
- Detailed specification of location on the grid,
- Specific size of the system,
- Modification of technology parameters (although it does allow new technologies to be added),
- Specification of prices for various grid services, or
- Modification of many calculation assumptions.

Some of these limitations are because the tool is intended for high-level analysis and screening, and some are because it is a publicly available tool. Future versions of the tool will address some of these limitations. Future versions will continue to be publicly available.

To run the model, no data are required, although the user must be knowledgeable about the general grid location for the system, services that are required by the grid (an estimated breakdown of system use if multiple services will be provided), and basic financial assumptions including peak and off-peak energy prices, cost of capital, and cost of equity.

The results from running ES-Select will indicate the appropriate technologies that are the best fit to provide the required services in the selected location based on installed cost, technology performance to meet service requirements, relevance to the selected location, and commercial maturity. Also provided are distributions to estimate what the user might expect based on his or her input parameters for economic value, market potential, cost of ownership, and payback period for the best-fit technologies. Distributions for technology characteristics are also available, including cycle life, discharge duration, efficiency, and energy density.

Using this output, a decision maker would be able to determine whether energy storage is a feasible option for specific requirements, the technologies that might be applicable along with their characteristics and expected costs, and an estimation of the expected economic value from the use of a storage system. Such information could be used to inform the use of the other tools detailed in this section to conduct a comprehensive performance and economic analysis to estimate the technical and economic performance that can be expected in the actual use of the selected storage systems.

A.2 Energy Storage Valuation Tool and Energy Storage Computational Tool

A.2.1 Energy Storage Valuation Tool by EPRI

EPRI has developed the Energy Storage Valuation Tool Version 3.1 (ESVT) to enable the assessment of energy storage cost-effectiveness in different use cases. ESVT was designed with goals of 1) site-customizable, 2) user-friendly, and 3) model and input transparency.

With a step-by-step user interface, it guides the user through the necessary steps to define and enter data for energy storage use cases (Figure A-3). ESVT calculates the value of energy storage use cases taking into account the full scope of the electricity system, including system/market, transmission, distribution, and customer services. ESVT also models a wide range of pre-loaded storage technologies, including several battery technologies, CAES, and pumped hydropower, leveraging EPRI's domain expertise in understanding the cost and performance of different storage technologies. It also models combustion turbine operation for business case comparison purposes. Input parameters of all technologies can be customized to best match the knowledge and expectations of cost and performance of the user.

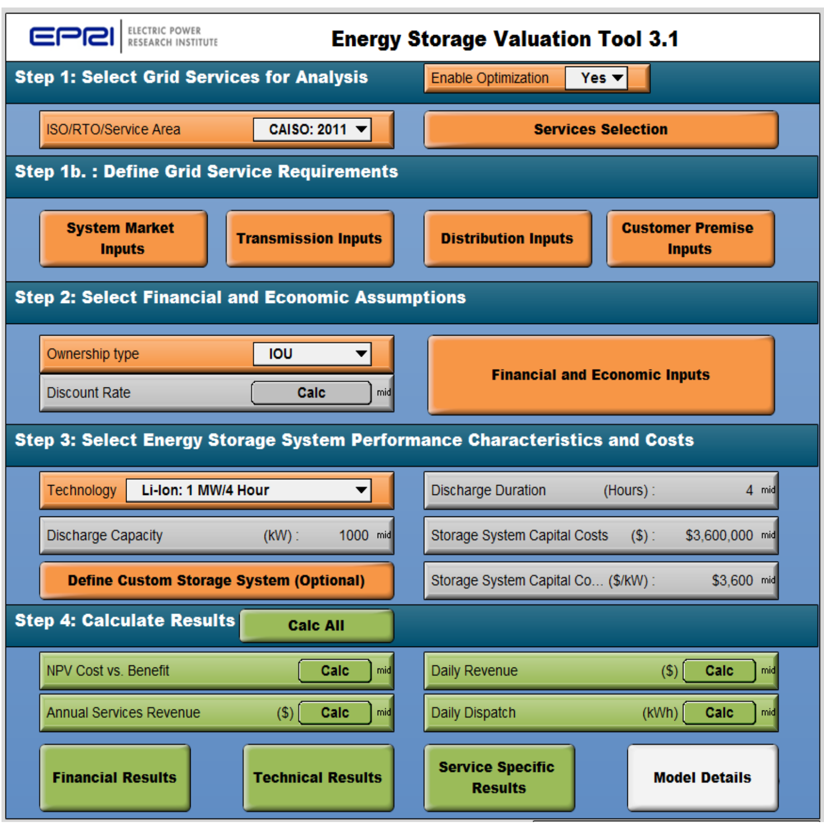

Figure A-3. Screen Capture of ESVT Main User Interface

ESVT simulates energy storage operation for different use cases with compatible grid services, based on user selections of location-specific load and price data, owner financial characteristics, and technology performance and cost information. The ESVT simulation engine utilizes a hierarchical dispatch that prioritizes long-term commitments over shorter ones and co-optimizes for energy storage system profitability across services where decisions are made in the day-ahead market.   A diagram of the key inputs, model operation, and outputs are displayed in Figure A-4.

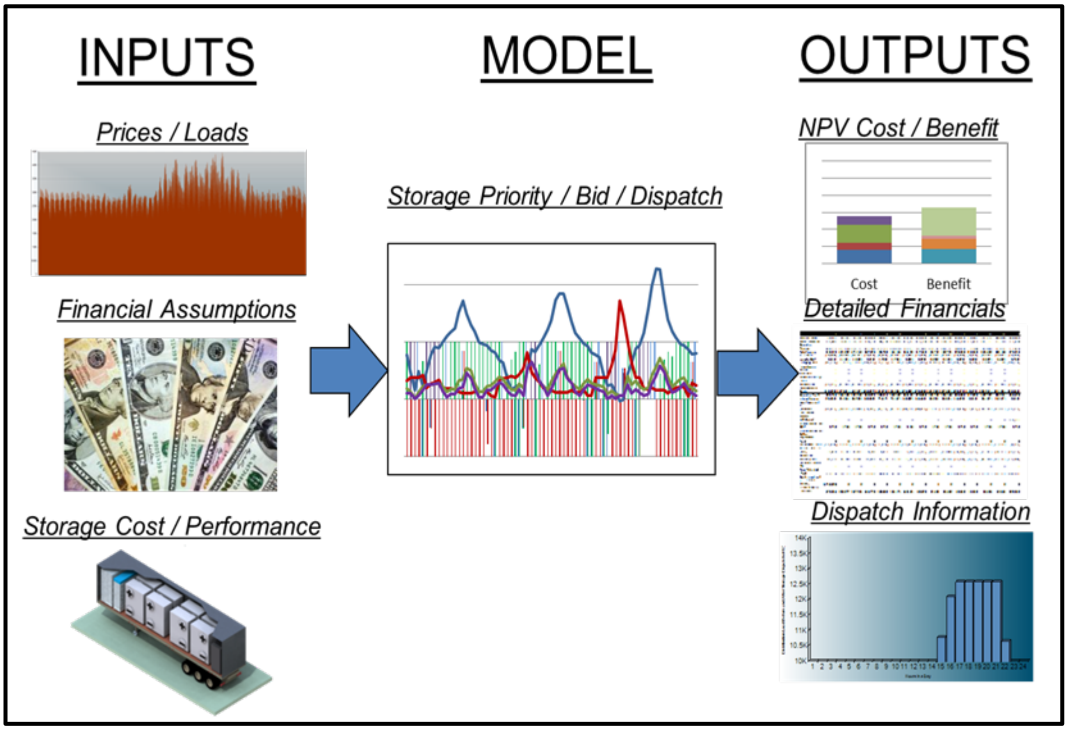

Figure A-4. Illustration of ESVT Operation

ESVT's outputs include financial results such as Net Present Value (NPV), financial pro forma statement, and technical simulation outputs such as cycle-life count. It also provides service-specific results such as annual revenue for each service and hourly dispatch results (Figure A-5 and Figure A-6). The tool calculates the potential value streams from the chosen grid service, accounting for the site-specific benefits and technical requirements to provide the service.

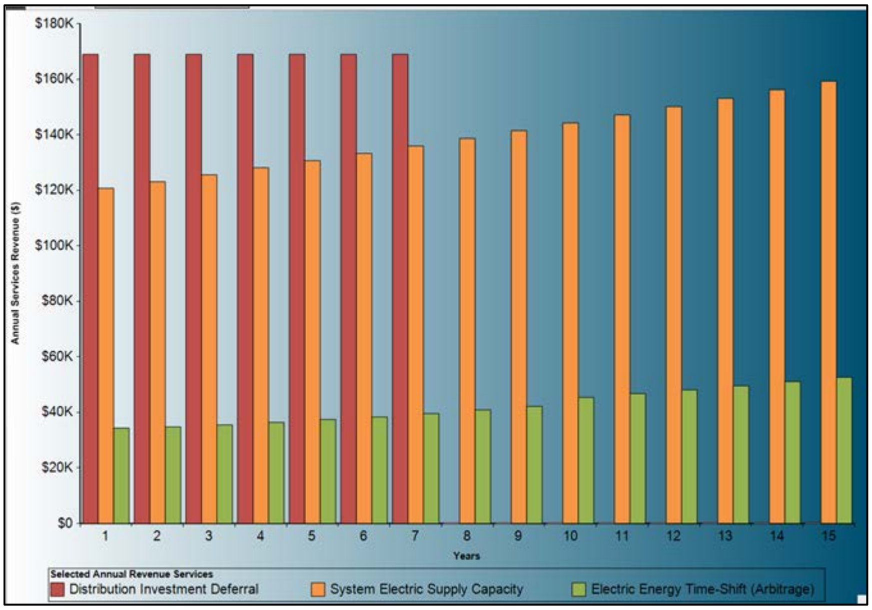

Figure A-5. ESVT Example Output: Energy Storage Annual Revenue by Grid Service

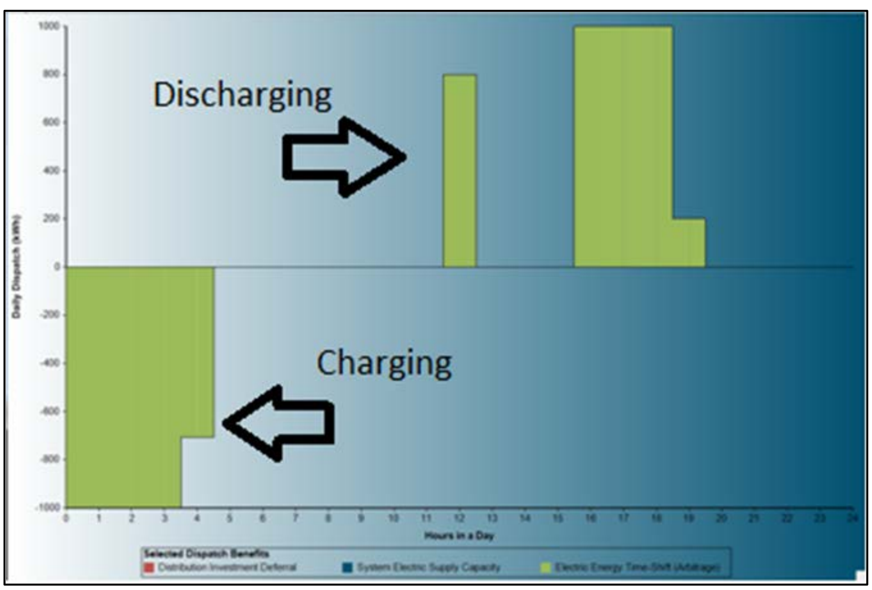

Figure A-6. ESVT Example Output: Simulation of Storage Charge/Discharge Dispatch

The Energy Storage Valuation Tool development continues with an updated model (Version 4) expected in mid-2014. Version 3.1 (issued April 2013) is currently available from www.epri.com (Product ID: 3002000312).

A.2.2 Energy Storage Computational Tool

The DOE Office of Electricity Delivery and Energy Reliability (OE) and the National Energy Technology Laboratory (NETL) tasked Navigant Consulting, Inc. to develop the Energy Storage Computational Tool (ESCT) to identify and quantify the benefits accrued through services provided by storage projects. The ESCT, an overview presentation, and a user guide can be downloaded from [www.smartgrid.gov.](www.smartgrid.gov)

The ESCT identifies 18 applications and their benefits, categorized as Economic, Reliability, or Environmental. The ESCT helps the user analyze the costs and benefits to determine the storage system's overall value. With this tool, the user can determine project costs and benefits to gain a clearer understanding of the financial benefits of the storage deployment. The user can also use the ESCT to analyze costs and benefits of storage deployments under different scenarios and assumptions. The monetary value of the benefits calculated by the ESCT could be attributed to ratepayers/utilities, non-utility merchants, end-users, society, or a combination of these parties, depending on the nature of the deployment and the applications pursued. The primary and secondary benefits that the ESCT calculates are assumed to accrue to the owner unless otherwise specified in the name of the benefit.

However, in determining the total value of storage, the ESCT aggregates all benefits regardless of who the likely benefactor is. Therefore, if the user wishes to carry out a more detailed cost-benefit analysis that is more specific to user benefits, the user can designate which of the various benefits accrue to the user specifically and complete this analysis separately. *The tool was not specifically designed to yield results to be used in regulatory hearings or other similar proceedings.* Ultimately, the results of the tool are intended for educational/screening purposes only and are meant to provide insight that can be used in conjunction with other analyses to understand more clearly the impact and benefits of storage to the grid.

Figure A-7 depicts the overall methodology that the tool employs to determine the monetary value of an energy storage deployment. In summary, the ESCT:

1. Characterizes energy storage projects in terms of technologies employed, location on the grid, regulatory structure, owner, and applications;
2. Identifies the economic, reliability, and environmental benefits the storage project could yield;
3. Guides the user through the process of entering data required for calculating the monetary value of benefits and associated capital and O&M costs; and
4. Estimates the NPV of the energy storage system over its lifetime, displayed as graphs and tables.

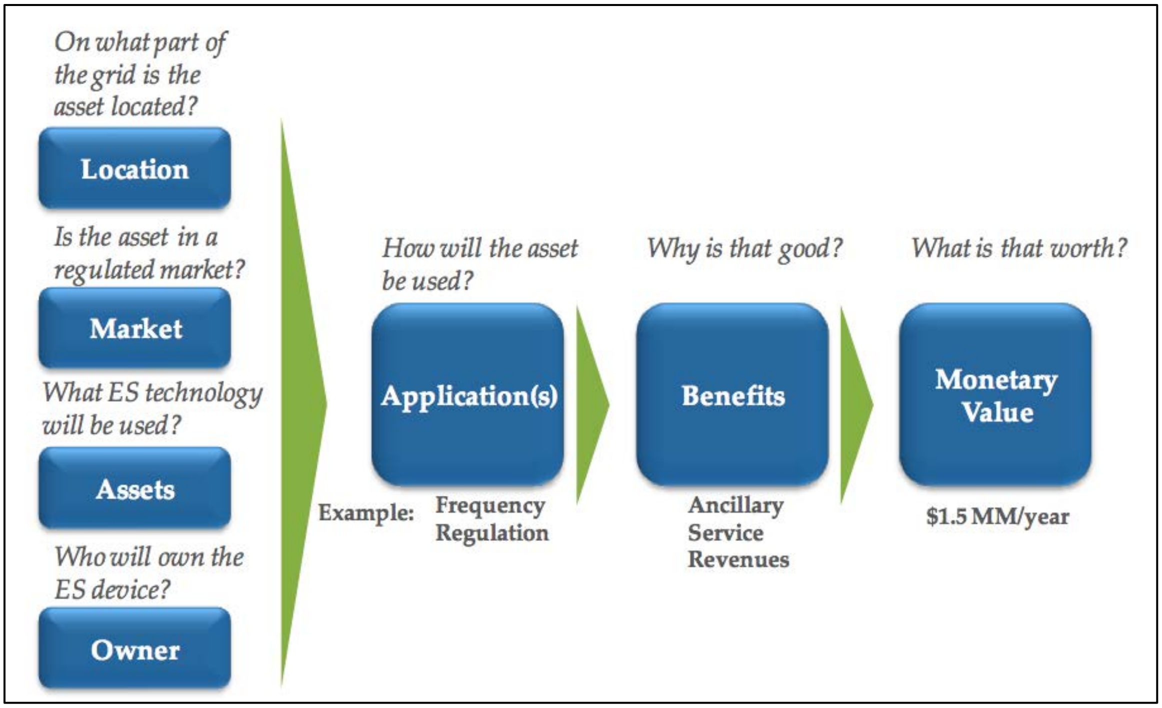

Figure A-7. Methodology for Determining the Monetary Value of an Energy Storage Deployment

A.3 Production Cost Simulation

A.3.1 Production Cost Modeling

There are different production cost models, all aiming to deliver the same result: a security-constrained economic dispatch of a system's generation units to meet load. In the case of renewable energy technologies, energy storage technologies, and other new power system assets, production cost modeling can be especially valuable in not only ensuring that demand can be met, but also in quantifying the value of these technologies relative to a system without their service. Production cost modeling is the professional standard of evaluation that would be employed to demonstrate the ability of a storage system to contribute to operating effectiveness, thereby helping to make the case to investors or a PUC.

In the past, production cost models have operated at an hourly resolution, optimizing by hour the operation and economics of a system. That was all that was necessary when generation units were directly controlled and load was relatively stable. However, with the integration of variable renewable generation, the increase in demand, and the variability of this demand, the value of hourly optimization models is limited, especially when evaluating the benefits of energy storage services. Newer models have the ability to increase this resolution to five-minute intervals – a feature that is essential to evaluating the operation of storage in highly variable systems.

Using production cost modeling, the user can specify the optimization windows for the models to evaluate to emulate reality as closely as possible, or conversely, to evaluate the minimum possible cost or evaluate the maximum possible value of a system addition. This optimization window is the timeframe over which the model will optimize dispatch at lowest cost. A daily window is the optimization of unit dispatch to meet demand over the day.

Specifically, using production cost modeling, the following analyses can be conducted:

- Economic analyses, including determining the overall production cost for an electricity system, the nodal electricity pricing for a system, and overall electricity pricing;
- Evaluating energy resource economics, including ancillary service, demand response, other contracts through basic markets analysis, and new asset analyses (including energy storage);
- Renewable energy analyses; and
- Service provision analyses.

Considering that the use of a production cost model requires detailed system data, including generator specifics, and at minimum, an hourly load profile (more on data requirements below), it develops a detailed characterization of a system's performance that can realize the above-listed analyses. This characterization includes:

- System-specific generation, load, assets, operations, market, ancillary service provisions;
- Overall costs: generation, start and shutdown, variable operation and maintenance, fixed costs, pump (charging) costs for storage, ancillary service costs, fuel costs, emissions;
- Pricing (system and nodal);
- Transmission line usage and congestion; and
- Nodal congestion.

This list highlights some of the value of a production cost model. There are other details that can be evaluated with the various production cost models available. More comprehensive information on their capabilities is available directly from the model vendors.

A.3.2 Limitations

While production cost modeling is a very powerful tool and can provide valuable analysis, there are some limitations. Often, results from production cost modeling are cited without noting these limitations, potentially misleading the reader about the robustness of the results.

As generally used, these models are unable to quantify the value of added capacity and thus resource adequacy. This quantification is especially important when considering energy storage technologies. This limitation results from short-timeframe runs, usually only one year, due to process speed and data limitations. This limited timeframe also presents issues in terms of risk in the form of load and renewables forecasting. For example, a value determined for a storage system that is associated with a one-year run may not accurately represent the value of the system in future years.

When using production cost modeling, these issues should 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.

A.3.3 Data Requirements

To evaluate a production cost model, the following items are required:

- Load data for the evaluation year in an hourly resolution, at minimum. For sub-hourly analysis, sub-hourly load data are required. For more comprehensive analysis, data for multiple years are necessary;
- Generation characteristics for all units on the system including max capacity, must-run requirements, seasonal ratings, ramp rates, heat rates, fuel types, start costs, variable O&M costs, maintenance details, and fixed costs;
- Transmission and distribution characteristics for nodal modeling: node specifications (load and voltage), transmission line details (max. and min. flow, resistance, and reactance);
- Fuel specifications;
- Reserve specifications: types, required provision, generators that can provide the reserve, and amounts that can be provided;
- Any contracts in place; and
- System operating constraints: for example, minimum or maximum limits.

A.3.4 PLEXOS

PLEXOS is a newer production cost model that allows the user to implement various energy storage resources. While the model is based on a pumped hydro setup using water as the working medium, other energy storage devices can be emulated with the pumped hydro construct. Using an energy model of the pumped hydro setup, it is possible to set maximum and minimum energy levels, roundtrip efficiency, and generation and pump capacities, as well as any associated costs to model an energy storage system.

As discussed previously, a production cost model is unable to dispatch resources to model regulation reserves. Instead, it holds those regulation reserves in a “regulation raise (and lower) reserve” category, where they cannot contribute to energy or other ancillary services. Thus it is assumed they will be available to meet any regulation requirements. However, in an energy storage system, even with the assumption that is typically made of an energy net zero in serving regulation resources over a long-enough timeframe − an hour in this case − there are losses due to the inefficiencies of charging and discharging. To address this energy loss, an auxiliary load is applied to the energy storage resources modeled. This means that whenever they are operating, there will be a load applied to the system. This continuous auxiliary load for each storage system type is calculated as:

$$aux\ load = (1 - ac\ roundtrip\ efficiency) * (25\%) * (average\ regulation\ raise\ provision)$$

where ac roundtrip efficiency is the storage system’s roundtrip ac-to-ac efficiency, 25% is an assumption of the amount of actual regulation energy demanded by the system relative to the amount provisioned, and the average provision is the averaged regulation reserve provision on the storage system over the year on an identical simulation run lacking an auxiliary load.

A.3.5 UPLAN-NPM[1]

UPLAN Network Power Model (UPLAN-NPM) is another commercially available production simulation and network model that can be used by system planners to evaluate energy storage systems. UPLAN models the detailed physical and financial operations of electricity markets under conditions ranging from traditional regulation to today's post-restructuring competitive market structures. UPLAN-NPM integrates electricity market simulation with a full (ac/dc) transmission network model; it projects hourly Locational Marginal Prices (LMP), and is fully compliant with the market design specifications of FERC Order 2000 and Standard Market Design (SMD). UPLAN-NPM has been used to simulate and analyze such regional markets as PJM, New York, New England, MISO, ERCOT and California. The day-ahead market is simulated in UPLAN by optimizing the commitment of resources for energy and all ancillary services taking into account transmission and inter-regional constraints. The commitment and dispatch algorithms incorporate both optimal power flow and resource scheduling to simulate the security constraints of a complete transmission network.

- UPLAN-NPM is a full network model designed to replicate the engineering protocols and market procedures of an operator. It captures the commercial activities, such as bidding, trading, hedging, and contracting, of all players in a restructured power market.
- UPLAN-NPM performs coordinated marginal cost-based energy and ancillary service procurement, incorporating operating costs, congestion management, and full-fledged contingency analysis. It incorporates Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) similar to those used by market operators.
- UPLAN-NPM co-optimizes energy and ancillary services market products (e.g., regulation, spin, non-spin, 30-minute spinning, and reliability must-run).
- UPLAN-NPM produces information on the projected hourly operation of generators, hourly balancing prices, and resulting generator energy delivered, as well as ancillary service revenue, costs, and net income. The model provides a projection of what is going to happen physically and financially throughout a region under specified circumstances (e.g. fuel prices, loads, outages, etc.) This enables the assessment of the engineering, economic, and financial implications of spatial and temporal changes in operations, reliability, production costs, and resources (e.g., generation capacity, retirements, remote and local renewable capacity, transmission expansions, etc.).

EPRI has conducted several regional case studies of energy storage using the UPLAN tool to illustrate approaches for modeling bulk and distributed energy storage systems. Some of these are listed below:

- Quantifying the Value of Hydro Power on the Electric Grid: Plant Cost Elements, EPRI, Palo Alto, CA, November 2011. EPRI Report 1023140.
- Grid Services from Hydropower and Pumped Storage, EPRI, Palo Alto, CA, December 2010, EPRI Report 1020081
- Economic and Greenhouse Gas Emission Assessment of Utilizing Energy Storage Systems in ERCOT, EPRI, Palo Alto, CA, November 2009, EPRI Product ID: 1017824

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[1] http://www.energyonline.com/products/uplane.aspx, last accessed April 28, 2013.

- Impacts of Energy Storage Systems in Addressing Regional Wind Penetration: Case Studies in NYISO and ERCOT, EPRI, Palo Alto, CA, December 2010, EPRI Product ID: 1020082.

A.3.6 Load Flow/Stability: PSS/E and PSLF

A.3.6.1 PSS/E

PSS/E is a software modeling tool developed by Siemens for use by electrical transmission planners and engineers. This software aids in designing and operating the transmission system. PSS/E can perform analyses such as power flow, fault analysis, dynamic simulations, and open access and pricing.

The PSS/E tool allows the user to see how the system can operate on a transmission system during dynamic and static loads. This knowledge helps the user determine the size of the energy storage required for stabilizing the electrical system. Most of the inputs are about the size, energy, and inverter parameters for filtering and response time.

Results include voltage and frequency stabilization and what contribution the energy storage system will have in providing short-circuit current on the system. PSS/E contains user cases that are pre-modeled for the Western Electric Coordinating Council (WECC), so adding energy storage in the WECC would be relatively simple because the model is already developed and basically validated.

Other models such as Positive Sequence Load Flow (PSLF) perform similar tasks. For small-signal analysis, software such as MATLAB/PowerSim may be more suitable. This is not as important at the transmission level compared to the distribution level.

Although other models exist, this version of the handbook considers the widely industry-accepted models listed above.

A.3.6.2 Positive Sequence Load Flow (PSLF)

PSLF is a power system analysis software package offered by General Electric (GE). PSLF is capable of solving static load flow problems as well as performing dynamic simulations; it is intended for the evaluation of large-scale power systems with as many as 60,000 buses.[2] PSLF contains an extensive library of component dynamic models for transmission lines, generators, and loads, as well as control components, such as exciters, power system stabilizers, relays, transformers, tap-changers, and more, that a user can include as building blocks when modeling a large-scale power system.

New dynamic models are often developed for PSLF through substantial project efforts. The focus is on realistic behavior and computational tractability rather than on representation of the system physics. Sophisticated physical processes, such as those in a hydro-turbine or steam-turbine, are often simplified to transfer functions with empirically derived coefficients. This

[2] "Power System Analysis Software," http://www.ge-energy.com/content/multimedia/_files/downloads/EC_Download_WilliamsS_Concorda%20PSLF%20Engine%20Fact%20Sheet%20GEA19666.pdf, last accessed March 25, 2013.

approach is in contrast to a physics-based model that might include the density of water or the temperature of steam in its model definition. In addition, all electrical quantities in PSLF are in terms of real power, reactive power, and reference frame variables: i.e., q-axis and d-axis voltages and currents. Thus for an energy storage system, PSLF would be suitable for tracking high-level characteristics such as battery state-of-charge, q-axis line current, and so forth, but it would not be suitable for modeling fine-scale physical or chemical phenomena in an energy storage device.

To evaluate a new component in PSLF, the first step is to develop a dynamic model of the component using the *epcl* programming language embedded within the software package. *Epcl* allows the definition of the system model as a set of ordinary differential equations. In the following example, the differential equations of a third-order wind turbine exciter are presented where @mx is the model index, remaining quantities beginning with @ are local variables, *epcexc[@mx].s0* is the exciter state s_0, and *epcexc[@mx].ds0* is the derivative ds_0 / dt, with the other states following the same syntax.

```
/* EPCL Example Begin*/
@piin  = epcexc[@mx].s0 - epcexc[@mx].s2 - @pref
epcexc[@mx].ds0 = (@pelec - epcexc[@mx].s0)/@tpw
epcexc[@mx].ds1 = @piin
epcexc[@mx].ds2 = (@kf*@kip*@piin + @kf*@kpp*(@pelec-epcexc[@mx].s0)/@tpw - /
                        epcexc[@mx].s2)/(@tf+@kf*@kpp)
/* EPCL Example End*/
```

The evolution of the system state is determined through numerical solution with a fixed time step, usually 4.2 msec, although this can be adjusted. The PSLF dynamic simulations typically consider tens or hundreds of seconds of time after some event or disturbance, such as a generator going offline or a transmission line being disconnected. PSLF is thus a valuable tool for evaluating the effect of energy storage components on system stability and robustness. However, PSLF would be impractical for evaluating the economic benefits of an energy storage system performing shifting, for example.

A simulation example based on an effort at Sandia National Laboratories to investigate the use of energy storage elements to mitigate inter-area oscillations on the WECC illustrates PSLF capabilities. In this study, a candidate UltraCapacitor-based oscillation damping system was developed and tested in PSLF.[3] First, the UltraCapacitor-based energy storage system with grid-tied inverter was developed (Figure A-8) and modeled using epcl. The new epcl model was inserted in two locations within an existing PSLF WECC base case with predicted characteristics for 2017 heavy summer. One damping control was connected to a bus in Palo Verde, and the other was connected near Grand Coulee Dam. Damping of inter-area oscillations was accomplished in simulation through power modulation control of the two systems that used the difference in bus frequencies in the two areas (Figure A-9).

[3] *Energy Storage Controls for Grid Stability*, Byrne, Ray, Jason Neely, Cesar Silva Monroy, David Schoenwald, and Ryan Elliot, November 2012, SAND-REPORT, Sandia National Laboratories, Albuquerque, NM.

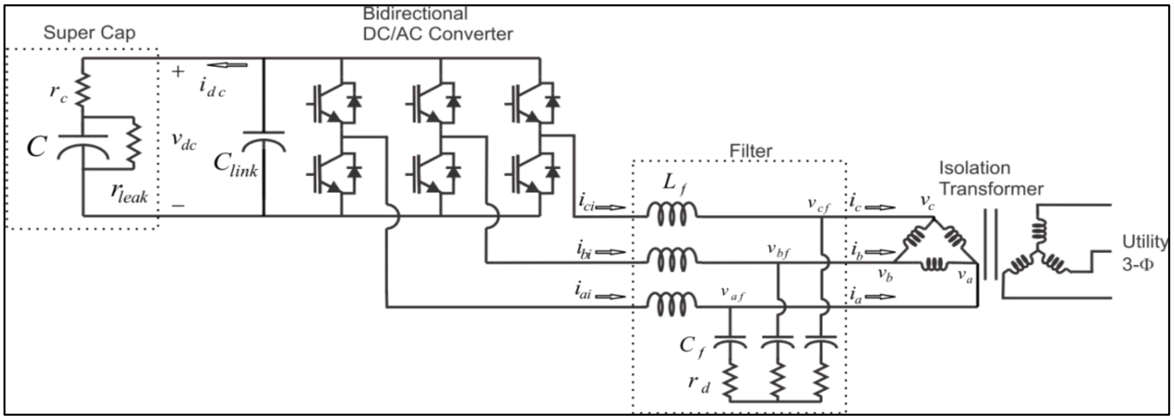
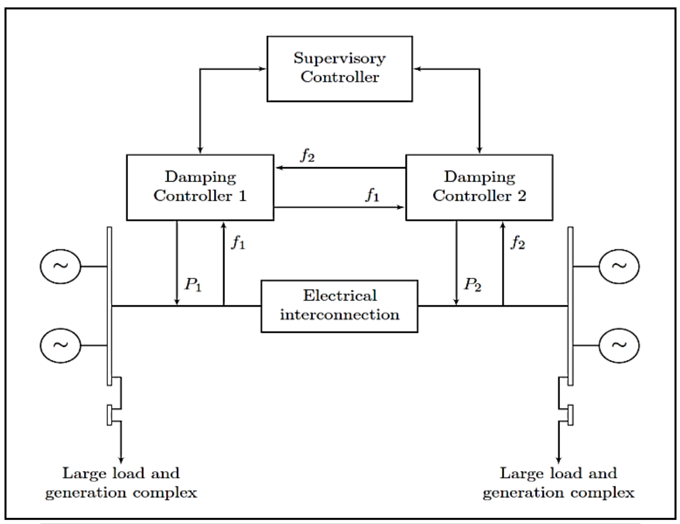


Figure A-8. Detailed Schematic Model of UltraCapacitor and Grid-Tied Inverter



$$\Delta P_1(t) = -K_d(f_1(t) - f_2(t-\delta))$$
$$\Delta P_2(t) = -K_d(f_2(t) - f_1(t-\delta))$$

Figure A-9. Damping of Inter-area Oscillations

For the simulation study, a transient inter-area oscillation was excited by simulating the loss of a 500kV power line in British Columbia. For a gain value of $K_d = 0$, the damping controllers had no effect, and the generator speeds in the two areas oscillated against one another for over 20 seconds (Figure A-10). For K_d = 10 MW/mHz, the oscillations were considerably damped, resulting in an oscillation that lasted approximately 7 seconds. Because PSLF provides results for the system-wide response, the effect of the damping controllers may be seen on generators across the WECC (Figure A-11).

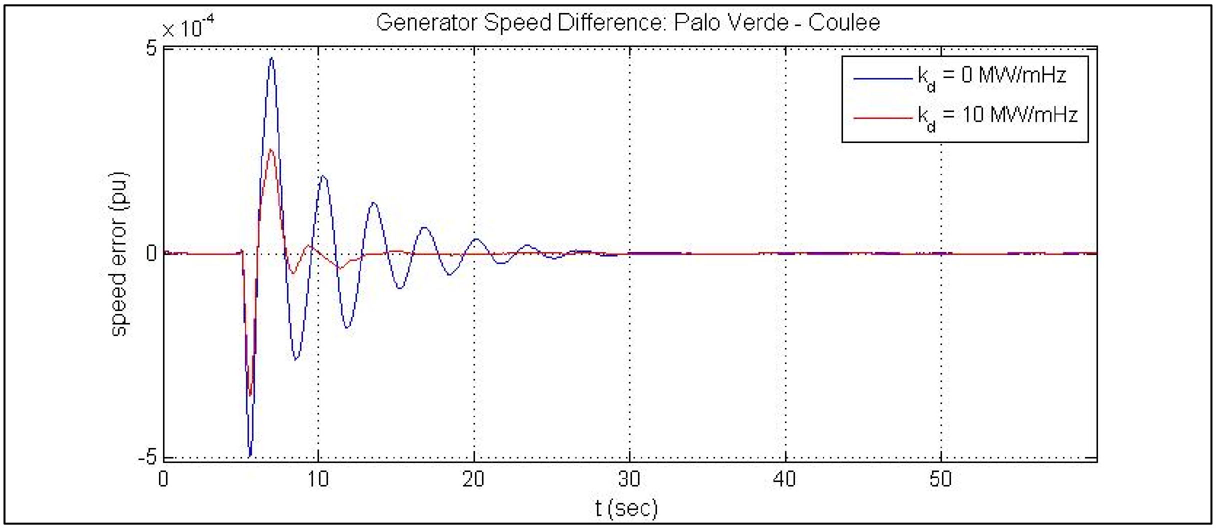


Figure A-10. Generator Speed Difference
(Simulation performed in PSLF; plot generated in Matlab.)

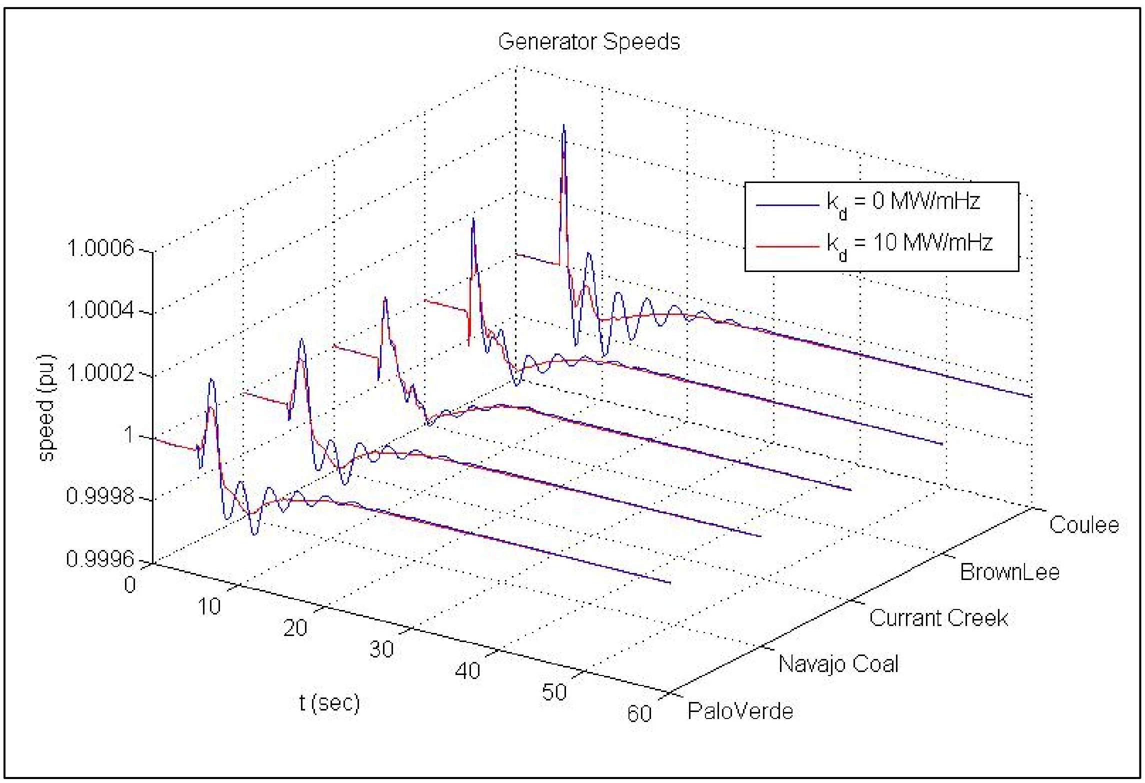


Figure A-11. Generator Speeds at Five Buses in the WECC With/Without Damping Control
(Simulation performed in PSLF; plot generated in Matlab.)

While this example employed GE's PSLF software, other software packages with similar capabilities for power system dynamic simulations include PSS/E offered by Siemens, Dynamic Security Assessment (DSA) Tools offered by Powertech Labs, and the PowerWorld Simulator offered by PowerWorld. Detailed information about the capabilities of each simulation environment is found on the company websites.[4, 5, 6]

[4] Power World Corporation, http://www.powerworld.com/, last accessed March 25, 2013.

[5] Siemens PSS® Product Suite, http://www.energy.siemens.com/hq/en/services/power-transmission-distribution/power-technologies-international/software-solutions/pss-e.htm, last accessed March 25, 2013.

[6] DSA Tools, http://dsatools.com/index.php, last accessed March 25, 2013.

APPENDIX B: STORAGE SYSTEM COST DETAILS

Appendix B: Table of Contents

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Appendix B: List of Tables

STORAGE SYSTEM COST DETAIL

The cost and performance data provided in the Handbook and in this appendix are based on EPRI report *"Electricity Energy Storage Technology Options 2012 System Cost Benchmarking"; EPRI ID 1026462, December 2012.*

Storage system costs have a "power" and an "energy" component. The power cost component is the cost of the power conditioning system and its auxiliaries, that determines the kW or MW capability of that particular system, and contributes to the $/kW component of the system cost. The energy component is the cost of the storage components – battery, flywheel, or the upper reservoir capacity in pumped hydro and related aux – that determines the kWh or MWh capability of the same system and contributes to the $/kWh of the system cost.

For a given system, the total cost is the sum of these components. This total cost is fairly specific to that system size, and is not linearly scalable in most cases. Using Table B-24 and the first system from Supplier S15 as an example, the sum of the $/kW and $/kWh is only applicable to discrete multiples of the system size of 1,000 kW/1,000 kWh. In most cases, these costs cannot be reliably extrapolated to a system size that is a fractional increment of this discrete size, such as 1,700 kW/1,200 kWh.

Continuing with the same system: Supplier S15 quoted the cost of the 1 MW/1MWh system to be $1,481,040, shown in the lower half of Table B-24, under "ES Equipment." This cost is vendor supplied and has not been altered. To this, we added other costs that are not included in the vendor quote, such as site installation, enclosure, interconnection, and other site specific costs, broken out in Equipment and Installation categories. This gives the "Total Cost Equipment" ($2,083,800); and "Total Cost Installation" ($254,972). To this, we further added project and process contingencies and engineering fees to derive a Total Plant Cost (TPC) = $2,476,567. (Note: the project and process contingencies are chosen based on our assessment of the maturity of the technology and vendor experience as discussed in Section B.1 and shown in Table B-3.)

The TPC divided by the power rating gives the TPC in $/kW; and when divided by the energy rating it gives the TPC in $/kWh for that specific system. In this case they are both = $2,477. The $/kWh of $2,477 is only for the rated depth of discharge. At 100% depth of discharge, the TPC would be divided by 3,030 kWh, yielding the lower $817/kWh value.

The Plant Capital Cost is a unit cost for the power ($847) and energy ($1,629) components, each multiplied by their respective rating and added gives the TPC. In this case, they are = $847,000 and $1,629,000. Added together, they give the TPC of $2,476,00 (rounded).

The interconnection and other site costs are our estimates as shown in Appendix D. These costs and all other adders shown in red in Table B-24 are our estimates which can be adjusted to your specific project needs.

B.1 Technical Approach and Assumptions

The 2011 cost benchmarking study was undertaken using the following approach:

1. Detailed cost and performance data sheets, shown in *Table B-1. Cost and Performance Data Sheets Provided to Survey Participants*, were prepared and sent to invited battery

OEM suppliers, power conditioning system (PCS) providers and system integrators. The list of companies contacted and their technology area is shown in *Table B-2. Vendors Contacted in the Cost and Performance Survey*.

2. Earlier 2010 data sheets were reviewed and updated based on new supplier input. An iterative approach was used with supplies to ensure scope of supply and cost information was presented on a consistent basis.
3. One-line electrical drawings and costs estimates for interconnection and step-up transformation were developed for each application to arrive at estimates for installed costs per electric utility requirements. These are shown in Appendix D, *Utility and Owner Interconnection Costs and Schematics for Various Storage Systems* (attached).
4. Process and project contingencies were applied based on technology maturity and level of development and commercialization as shown in *Table B-3. Process and Project Contingency Assumptions*.
5. Cost metrics were defined to consistently compare installed and life-cycle costs across systems and applications. See the discussion below for definitions.
6. Financial and levelized cost of ownership methods and analysis were developed for several industry ownership scenarios including IOU, municipal utility, and IPP. The methodology and analysis are described in this appendix.
7. Given uncertainty and lack of credible O&M data, proxy estimates were developed for fixed, variable, and replacement costs.

The cost basis of these estimates must be understood to compare energy storage options presented appropriately. Site-specific conditions with more detailed energy storage use cases defined can result in quite different and varying estimates for installed costs and system life-cycle estimates than those presented. The assumptions made in the study include:

1. The cost estimates presented in the study are representative base costs for the energy storage system and do not include all the owner's financial costs or site-specific project costs except for pumped hydro.
2. The following owner's financial costs are excluded from the estimates:
   - Interest During Construction (IDC)
   - Project Insurance and Project Escalation
   - Financing Fees
   - Allowance for Funds Used During Construction (AFUDC)
   - Sales Tax
   - Bonds
   - Legal Fees
   - Construction Power
   - Other Owner's Costs and Escalations.
3. The following site-specific project costs are excluded from the estimates for all technologies except pumped hydro and CAES:
   - Environmental Studies

- Preliminary Engineering and Geology Work
- Water Rights
- Right of Way
- Start Up
- Permitting
- Off-Site Infrastructure
- Supporting Utilities (water, shore power, sewer, and communications)
- Substation and New Transmission (unless otherwise shown in base estimate as utility interconnection)
- Access (ingress and egress)
- Security (lighting, fencing and communications)
- Civil Site Preparation
- Land Acquisition.

4. Battery and flywheel systems are assumed to be located at brownfield sites where site-specific projects costs are not included, because these associated assets are assumed to be adjacent to the site or in place. Therefore, these estimates represent an installed TPC less the owner's costs. These sites would be typical of a prepared site such as a utility substation or a private owner's property that is fully prepared for the project. The applicable utility and owner interconnection costs for battery and flywheel systems are included in the cost estimates.

5. CAES systems are assumed to be located at greenfield sites where site-specific project costs are not included. This site would be typical of an unprepared or new site for a utility or a private developer and requires the inclusion of all the listed site-specific project costs. To complete the installed TPC for CAES systems, owner's costs, site-specific costs, step-up transformers, and utility/owner interconnection costs must be added.

6. Pumped hydro systems are assumed to be located at greenfield sites where site-specific project costs are included in the cost estimates. This site would be typical of an unprepared or new site for a utility or a private developer that includes all the listed site-specific project costs. Therefore, these estimates represent an installed TPC less the owner's financial costs. The utility and owner interconnection transmission line costs for pumped hydro systems are also not included in the cost estimates; however, site-specific generator step-up transformers and the site substation are included in the site-specific costs.

7. IOU financial ownership scenarios were used.

Other key financial assumptions are shown in *Table B-4. Key Financial Assumptions and Levelized Costs* and technology-specific assumptions are listed in the associated technology sections in this appendix.

Table B-1. Cost and Performance Data Sheets Provided to Survey Participants

(Highlighted parameters are vendor inputs)

LINE NUMBER	AECOM ENGINEERING
	Advanced Lead Acid
	Application
	Technology Type
	tech
	System Size & Status
	Storage Capacity (Hours)
	Supplier
	Technology Chemistry
1	**DESIGN BASIS - General**
2	System Capacity - Net kW
3	Hours of Energy storage at rated Capacity - hrs
4	Depth of Discharge (DOD) per cycle - %
5	Energy Capacity - kWh @ rated DOD
6	Energy Capacity - kWh @ 100% DOD
7	Auxiliaries - kW
8	Unit Size - Net kW
9	Number of Units - #
10	Physical Size - SF/Unit
11	System Foot Print - SF
12	System Weight - lbs
13	Round Trip AC / AC Efficiency - %
14	Number of cycles / year
18	**DESIGN BASIS - Temperature**
19	Design Summer Ambient T - °F
20	Design Winter Ambient T - °F
21	**GENERAL - Timing**
22	Year $ for Input Data
23	Month $ for Input Data
24	Commercial Order Date
25	Commercial Service Date
26	Book Life, yrs
27	Plant Life, yrs
28	Pre-construction Time, yrs
29	**TOTAL PLANT COST**
30	$/kW
31	$/kWh @ rated DOD
32	$/kWh @ 100% DOD
38	**PLANT CAPITAL COST**
39	Power - $/kW
40	Storage - $/kWh @ rated DOD
41	

43	**SYSTEM COSTS - Equipment & Install**
44	
45	**ES System**
46	ES Equipment
47	ES Installation
48	Enclosures
49	**Owner Interconnection**
50	Equipment
51	Installation
52	Enclosures
53	**System Packing**
54	
55	**System Shipping to US Port**
56	
57	**Utility Interconnection**
58	Equipment
59	Installation
60	
61	**Site BOP Installation (Civil Only)**
62	
63	**Total Cost Equipment**
64	**Total Cost Installation**
65	
66	General Contractor Facilities at 15% install
67	Engineering Fees @ 5% Install
68	Project Contingency Application @ 0-15% install
69	Process Contingency Application @ 0-15% of battery
70	**Total Plant Cost (TPC)**
71	**Plant Cost - $/kW**
72	**Plant Cost - $/kWh @ rated DOD**
73	**OPERATING EXPENSES**
74	**FIXED O&M - $/kW-yr**
75	Replacement Battery Costs - $/kW
76	Battery replacement - yrs
77	**Variable O&M - $/kWh (Charging or Discharging)**

82	**PERFORMANCE - General**
83	**Energy Storage (ES) Capacity:**
84	Useable ES Capacity at Nominal output - kWh
85	Nominal Power Output per Line 84 - kW
86	Nominal Power Input per Line 84 - kW
87	**Charging Performance:**
88	Maximum Power Input for 15 min - kW
89	Maximum Power Input for 1 hr - kW
90	Maximum Power Input for 5 hr - kW
91	Sustainable Minimum Power Input - kW
92	Nominal Ramp Rate - kW/sec
93	**Discharge Performance:**
94	Maximum Power Output for 15 min - kW
95	Maximum Power Output for 1 hr - kW
96	Maximum Power Output for 5 hr - kW
97	Sustainable Minimum Power Output - kW
98	Nominal Ramp Rate - kW/sec
99	**Spinning Reserve Response - immediate or time delay**
100	**Operating Reserve:**
101	Cold Start-up - kW/Sec
102	Cold Start-up - kW output in 5 minutes
103	**Duty Cycle:**
104	Cycles/Year
105	Time to Fully Charge (at Nominal Power Input)-hrs
106	Time to Functionally Discharge (at Nominal Power Output)-hrs
107	Minimum Load - %

Table B-2. Vendors Contacted in the Cost and Performance Survey

A123 Systems/Li-ion	International Battery/Li-ion
ABB Inc./Inverter	IONEX Energy Storage Systems/Li-ion
Altairnano/Li-ion	Isentropic/Pumped Heat Energy Storage
Aquion Energy/Aqueous Hybrid Ion	LG Chem/Li-ion
Beacon Power/Flywheel	NEC/Li-ion
Beckett Energy Systems/Li-ion	Parker Hannifin/Inverter
Boston Power/Li-ion	Powergetics
BYD/Li-ion	Premium Power/Zn-br
Chevron Energy Solutions	Primus Power/Zn-Halogen
Dow Kokam/Li-ion	Princeton Power/Inverter
Dresser-Rand/CAES	Prudent Energy/Vanadium Redox
DynaPower/Inverter	RedFlow/Zn-Br
Ecovoltz/Flow Battery	Ricardo Inc./Integrator
Ecoult-EastPenn/Adv. Lead-acid	ReVolt/Zn-air
EnerSys/Adv. Lead-acid	Saft/Li-ion
EnerVault/Fe-Cr	S&C Electric/Li-ion
EOS/Zn-air	Siemens/Inverter
Exide/Adv. Lead-acid	Samsung SDI
FIAMM/NaNiCl2	Satcon/inverter
Fluidic Energy/Zn-air	Silent Power/Adv. Lead-acid
GE/NaNiCl2	Sunverge Energy/Li-ion
Green Charge Networks/Li-ion	SustainX/Isothermal
Greensmith/Li-ion	Toshiba Corp.
GS Yuasa/Adv. Lead-acid	Xtreme Power/Adv. Lead-acid
Highview Energy/Liquid-air	ZBB Energy/Zn-br
	Zinc Air Inc./Zn-air

Table B-3. Process and Project Contingency Assumptions

Technology	5kW - 50kW		100kW - 1MW		2MW - 10MW		25MW - 100MW		101MW - 500MW	
	Process	**Project**	**Process**	**Project**	**Process**	**Project**	**Process**	**Project**	**Process**	**Project**
CAES	na	na	na	na	10%	10%	10%	10%	10%	10%
Pumped Hydro	na	na	na	na	na	Na	na	na	Included	Included
NaS	0%	0%	0%	5%	0%	5%	0%	10%	na	na
Advanced Lead-Acid	5%	0%	5%	5%	5%	5%	5%	10%	na	na
Li-ion	10%	0%	10%	5%	10%	5%	10%	10%	na	na
Vanadium Redox	5%	0%	5%	5%	5%	5%	5%	10%	na	na
Zn/Br	10%	0%	15%	10%	15%	10%	15%	15%	na	na
Fe/Cr	15%	0%	15%	10%	15%	10%	15%	15%	na	na
Zn/Air	15%	0%	15%	10%	15%	10%	15%	15%	na	na
Flywheel	na	0%	na	na	na	Na	0%	na	na	na
Sodium Metal Halide	na	na	10%	5%	10%	10%	10%	10%	na	na
Aqueous Hybrid Ion	na	na	na	na	na	Na	15%	15%	na	na

Notes: Read “na” as not assessed in this study.

Table B-4. Key Financial Assumptions and Levelized Costs

Ownership Default Financials	IOU	Muni	IPP w/Contract	IPP - No Contract
Equity Share in Capital Structure	50%	0%	30%	60%
Cost of Debt	6.00%	5.00%	6.60%	7.40%
After Tax WACC	7.30%	5.00%	8.00%	10.50%

FINANCIAL ASSUMPTIONS	
Inflation Assumptions	
Fixed O&M Cost - Escalator (%/yr)	2.0%
Variable O&M Cost - Escalator (%/yr)	2.0%
Electricty/Fuel Inflation	5.0%
Fuel Cost Assumptions	
Charging Cost ($/MWh)	$30.00
Fuel Cost ($/MMBtu)	$3.00
GHG Assumptions	
CO2 Emissions (Lb/MMBtu)	117
CO2 Price ($/Ton)	$30.00
Fixed Cost Assumptions	
Insurance	0.50%
Property Tax	1.00%
Insurance Expense ($/kW)	$0.00
Financing Assumptions	
Ownership	IOU
Percent Financed with Equity	50.00%
Debt Interest Rate	6.00%
After-Tax WACC	7.30%
Pre-Tax WACC	8.52%
Cost of Equity	11.04%
Target average DSCR	1.40
Debt Term	15
Tax Assumptions	
COD Year	2012
Income Tax - Federal	35%
Income Tax - State	8.84%
Total Tax	40.75%
Tax Depreciation (MACRS) schedule (yrs)	10
Royalty Payment to Landowner	0.25%
Tax Credit - Federal ITC (%)	0.00%
Tax Credit - Federal ITC Expiration	2012
Federal Investment Tax Credit (ITC) ?	☐
Sales Tax - State Rate (no exemption)	4.00%
Sales Tax - Average Local Rate	1.38%
Sales Tax - % of Capital Cost Subject to Sales Tax	80%

DETAILED FINANCIAL INPUTS	
Detailed Tax Assumptions	
Federal Production Tax Credit (PTC) ?	☐
Tax Credit - Federal PTC ($/MWh)	$0.00
Tax Credit - Federal PTC Expiration	2012
Tax Credit - Federal PTC (Years)	10
Tax Credit - Federal PTC Escalator	2%
Tax Credit - State expiry (end year)	0
Tax Credit - State ITC (%)	0.00%
Tax Credit - State Tax Credit ($/MWh)	$0.00
Tax Credit - State Tax Credit ($ millions)	$0.0
Tax Credit - State Tax Credit Annual Max (% capex)	0.00%
Tax Credit - State Tax Credit Annual Max ($mill)	$0.00
Tax Credit - State Tax Credit Duration (Years)	0
Sales Tax - State Rate	4.00%
Sales Tax - State & Local Combined	5.38%
Sales Tax - Maximum per MW	$0
Sales Tax Exemption Expiration	2011
Gross Receipts Tax - State Rate	0.00%
Gross Receipts Tax - Average Local Rate	0.00%
Gross Receipts Tax - State & Local Combined	0.00%
Property Tax - During Exemption Period	0.50%
Property Tax - Exemption Expiration (end year)	2015
Property Tax - Straight-line Depreciation (0=None)	20
Excise Tax - State Tax Rate ($/MWh)	$0
Excise Tax - tax holiday period	0
Payments-In-Lieu-Of-Taxes (PILOT) - ($/kW)	$0.00
Payments-In-Lieu-Of-Taxes (PILOT) - ($/MWh)	$0.00

***Muni financing is similar to Cooperative financing with 100% debt, 5% cost of debt, etc. Note that even with 100% debt, there will always be a coverage ratio of 1.25 or more.*

Note: DSCR stands for Debt Service Coverage Ratio.

Project contingency reflects uncertainties in major equipment costs and installation and integration costs. Systems that have been field-demonstrated have low project contingencies. Systems still in R&D, with limited or no integration or field deployment history are assigned a higher project contingency. Project contingency is applied by multiplying the total estimated cost of a storage system installation by the project contingency percentage then adding this to the estimated TPCs.

B.2 Cost Metrics

The cost for each storage technology is calculated using a detailed utility revenue requirement model. The levelized price for delivered energy is calculated to achieve the target return on equity for the project. All results presented are based on an investor-owned utility with an after-tax weighted cost of capital of 7.3%. The present values of the fixed and variable costs over the life of the project are calculated and then used to calculate the levelized and present value cost metrics described below. In addition to debt and equity payments, the primary annual costs for the storage technologies are charging costs (electricity, fuel, and CO2) fixed O&M ($/kW installed), and variable O&M ($kWh discharged). Periodic maintenance, such as module replacement, is also included for some technologies. Additional costs such as insurance and property tax are based on a percentage of total installed costs.

There are no costs per cycle included. However, the annual charging costs are based on the number of cycles assumed per year for each application, the kWh of energy storage (duration), and the round-trip efficiency.

The five summary cost metrics are:

1. **Installed Cost ($/kW)**

   The installed cost includes all equipment, delivery, installation, interconnection, and step-up transformation costs. For this benchmarking work it was assumed a site was available; however no land costs, permitting, and project planning costs were included. These costs are comparable to the installed costs of a combustion turbine (CT) or combined-cycle gas turbine (CCGT) for up-front capital and financing requirements.

2. **Levelized Cost of Capacity ($/kW-yr.)**

   The levelized cost of capacity is the $/kW-yr. revenue per kW of discharge capacity needed to cover all life-cycle fixed and variable costs and provide the target rate of return based on financing assumptions and ownership types. This metric is primarily of interest for comparing to capacity resources, such as a CT.

3. **Levelized Cost of Energy (LCOE) ($/MWh)**

   The LCOE is the $/MWh revenue for delivered energy needed to cover all Life-cycle fixed and variable costs, and provide the target rate of return based on financing assumptions and ownership types. This metric is primarily of interest for energy resources such as renewables or baseload fossil generation.

4. **Present Value of Life-cycle Costs ($/kW Installed)**

   The Present Value of Life-cycle Costs includes the installed costs (above) and all ongoing fixed and variable operating costs over useful life. The present value of the annual costs is divided by the kW of energy storage system discharge capacity installed.

5. **Present Value of Life-cycle Costs ($/kWh Installed)**

   The Present Value of Life-cycle Costs described above divided by usable kWh of energy storage capacity installed. Both of the Present Value of Life-cycle Costs metrics can be compared against estimates of present value benefits or revenues to estimate cost-effectiveness.

These cost metrics are provided for broad comparisons of different energy storage technologies with each other and to a combustion turbine (CT). For purposes of consistent comparison across a broad range of technologies\ simple assumptions are required regarding the dispatch of energy storage in the representative applications presented. Actual costs across storage technologies for specific sites and applications will vary considerably from those presented here. Nevertheless, these metrics give useful indications: for example, how a low-cost, less-efficient storage technology compares to a higher-cost, more-efficient storage technology.

The applicability of each cost metric depends on the application under consideration. A utility interested in adding a capacity resource that will run a limited number of hours each year is most concerned with the Installed Cost ($/kW) and Levelized Cost of Capacity ($/kW-yr) metrics. These are the metrics used by utilities to estimate the full costs of a new CT, which is often used as a benchmark for alternative capacity resources such as demand response. Because the resource is expected to operate at a low capacity factor, the cost of delivered energy is not of particular concern and may be relatively high.

On the other hand, a utility interested in adding an intermediate generating resource, with a high capacity factor, may be more interested in the cost of the energy produced, and thus looks at the $/MWh LCOE metric. This metric is often used to compare to the delivered cost of energy from different renewable energy technologies in different regions.

The Present Value of Life-cycle Costs ($/kW or $/kWh Installed) are presented specifically for energy storage and are not commonly used for fossil resources. The primary value or revenue from fossil resources is readily compared to market prices or proxy resources. Determining the value of storage performing multiple services is more difficult. The Present Value of Life-cycle Costs is designed to be compared against corresponding estimates of present value benefits or revenues. The present value of revenues can be compared against the present value of costs to estimate cost-effectiveness of an individual technology for a specific application.

B.2.1 Life-cycle Cost Analysis

Levelized cost and life-cycle analysis metrics are valuable metrics for assessing and benchmarking energy storage options within a specific application and use case requirement. The analysis methods used to estimate the levelized cost of energy ($/MWh) and the levelized cost of capacity ($/kW-yr.) are presented in this section.

EPRI research supported the development of a Life-cycle Analysis Calculator (Calculator) to conduct easy estimation of these metrics based on system/technology features, ownership scenarios, and financial assumptions. Vendor data obtained from the survey was used as input to the Calculator to estimate the results presented in this appendix. *Table B-5* lists the key system feature inputs necessary, while *Table B-4* (above) details the key financial input assumptions. The Calculator has the capability to estimate these metrics from several ownership perspectives, including investor-owned utility, municipal utility (Muni), and IPP. The IPP option includes inputs for both a contracted and a merchant (non-contracted) storage project. The debt-to-equity ratio, cost of debt, return on equity, and resulting weighted average cost of capital (WACC) appropriate for each option are included in the model.

Table B-5. Example Life-Cycle Calculator

COST AND PERFORMANCE DATA		
System Size		
Charge/Discharge Capacity (kW)	kW	1000
Hours of storage at rated capacity	hours	4
Depth of Discharge per cycle	%	0.8
Useable Energy Storage Capacity (kWh)	kWh	4,000
Installed Energy Storage Capacity	kWh	5,000
Useful Life		
End-of-Life Residual Energy Storage	%	100.00%
Degradation Factor (%/yr)	%	0.00%
System Life	Years	15
Efficiency		
AC/AC Efficiency OR	%	80%
Energy Charge Ratio	kW in/kW out	-
Output		
Cycles per Year	#	365
Installed Cost		
DC Battery Cost per kWh of usable storage	$/kWh	$390
Total DC Battery Cost	$	$1,560,000
$/kW installed (incl PCS)	$/kW	$527
Total $/kW Cost	$	$527,000
Total	$	$2,087,000
Cost per kW	$/kW	$2,087
System Cost - Regional Multiplier	Ratio	1.000
System Cost - Regional Cost	$/kW	$2,087
	$/Useable kWh	$522
Fixed O&M		
Fixed O&M Cost	$/kW-Yr.	$4.5
Periodic Major Maintenance	$/kW	$0
period between maintenance	years	8
Property Tax	% of $/kW capex	1.0%

COST AND PERFORMANCE DATA		
Insurance Cost	% of $/kW capex	0.5%
Variable O&M		
Variable Costs	$/kWh produced	$0.00140
Charging Costs		
Avg. Charging Cost	$/MWh	$30.00
Fuel Cost	$/MMBtu	$3.00
Fuel Cost Escalation	%	5%
CO_2 Emission Rate by Fuel	lb/MMBtu	117
CO_2 Allowance Price	$/ton	$30
Heat rate	Btu/kWh	-
Annual Heat Rate Degradation	%	
Fixed O&M Cost - Escalator (%/yr)		2.0%
Variable O&M Cost - Escalator (%/yr)		2.0%
Finance		
Ownership		IOU
Percent Financed with Equity	%	30%
Debt Interest Rate	%	6.60%
After-Tax WACC	%	8.00%
Cost of Equity	%	17.54%
Target average Debt Service Coverage Ratio	ratio	1.40
Debt Term	Years	15

B.2.2 Financial Assumptions

Table B-4 (above) lists the key financial assumptions used to calculate the present value of installed cost, levelized cost of energy, and levelized cost of capacity. For this appendix, the IOU ownership scenario was used in all calculations and estimates. For the IOU financing scenario, the financing is 50% debt and 50% equity with a WACC of 7.3%.

Other assumptions used throughout the analysis are also shown in Table B-5. Gas prices start at $3.00/MMBtu in 2012 and escalate at 5% per year. Electricity charging costs for energy storage are based on an off-peak energy cost of $30/MWh, also escalated at 5% per year. A flat carbon price of $30 per short-ton is included for gas-fired technologies. The model includes inputs for various tax credits, but none are used in this report (beyond deductions for interest expense and depreciation).

The ownership assumptions affect the present value of installed costs and life cycle analysis due to differences in WACC, income tax rates, etc. Figure B-1 (below) illustrates the sensitivity to ownership approach for an example 50-MW/6-hour NaS battery. Tax-free, debt-only financing for municipal utilities provides the lowest levelized cost. The next highest is the IPP with a power purchase agreement. The return on equity is higher than for an IOU, but the presumed debt ratio also higher. This results in a slightly lower WACC than for an IOU with 50% debt and equity. An un-contracted IPP asset has the highest return on equity and WACC and therefore the highest levelized cost.

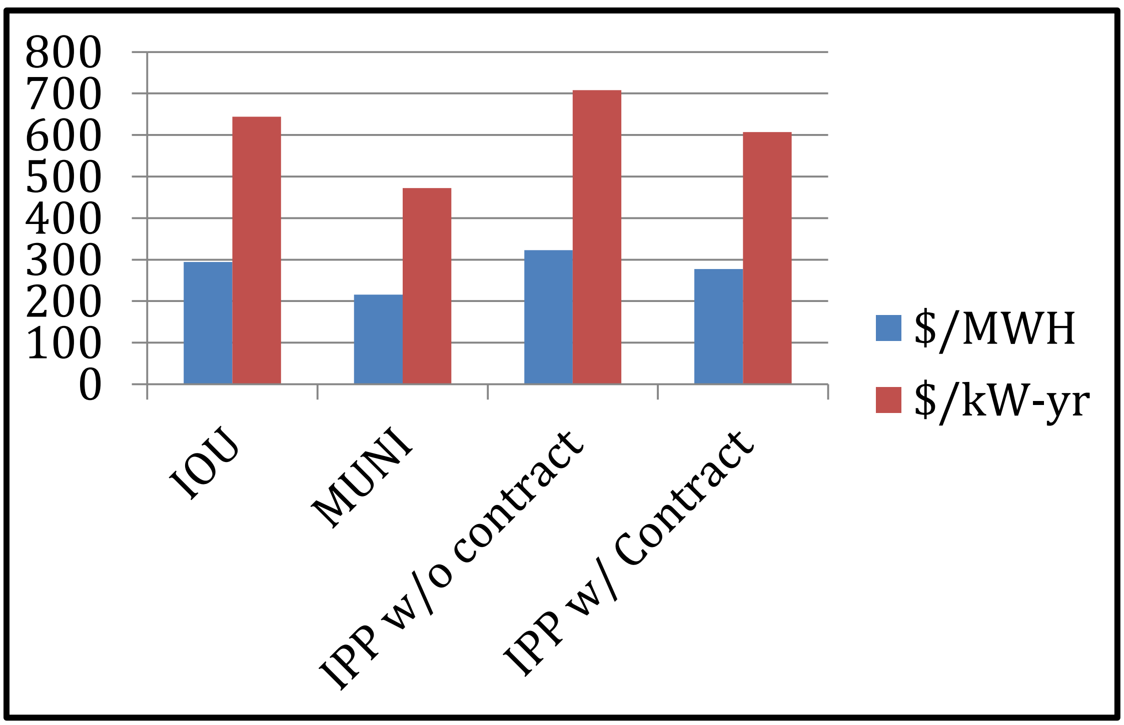


Figure B-1. Impact of Ownership Assumptions

(Example estimated for 50-MW/6-hour NaS Battery @ $3071/kW installed, 365 cycles/yr.; 15 years; 75% efficiency; $30/MWh cost of off-peak energy.)

B.2.3 Methodology

Life-cycle costs are modeled with a detailed annual cash-flow analysis. The inputs to the cash-flow analysis for a 50-MW/6-hour NaS battery are shown in Table B-6 and Table B-7. These include the storage cost and efficiency inputs as well as the financial inputs described above.

The model employs a revenue requirement model for IOU or Muni financing and an after-tax cash flow model for IPP financing. The first years of the IOU revenue requirement model are shown in Table B-8 (again for the 50-MW/6-hour NaS battery). The upfront capital investment is split 50% debt and 50% equity in year zero (2011). For each operational year, an annual utility revenue requirement is calculated including interest payments on debt, return on ratebase, and taxes. The levelized price for delivered energy is calculated to achieve the target return on equity for the project. The present values (PVs) of the fixed and variable costs over the life of the project are calculated and then used to calculate the levelized and present value cost metrics (Table B-9).

Table B-6. Example Key System Inputs for the Life-cycle Cost Analysis for a NaS Energy Storage Option

Energy Storage System Maturity	
Technology Type	**NaS**
System Size	**50 MW**
Storage Capacity (Hours)	**6**
Unit Capacity, Net kW	50,000
Hours of Energy storage at rated Capacity	6
Depth of Discharge (DOD)	80%
Plant Life	15 Years
Round Trip AC/AC Efficiency	75%
Number of cycles/year	365
Total Plant Cost - $/kW	$3,071
Total Plant Cost - $/kWh @ rated DOD	$512
Total Plant Cost - $/kWh @ 100% DOD	$409
Power Cost - $/kW	$516
Storage Cost @ rated DOD $/kWh	$426
Periodic Major Maintenance - $/kW	-
Period between Maintenance, yrs	-
Fixed O&M - $/kW-yr	$4.5
Variable O&M - $/kWh	$0.0005

Table B-7. Input Assumptions for 50-MW/6-hour NaS Battery

COST AND PERFORMANCE DATA		Bulk NaS 50 MW 6 Hrs S36
System Size		
Charge/Discharge Capacity (kW)	kW	50,000
Hours of storage at rated capacity	hours	6.00
Depth of Discharge per cycle	%	80%
Useable Energy Storage Capacity (kWh)	kWh	300,000
Installed Energy Storage Capacity	kWh	375,000
Useful Life		
End-of-Life Residual Energy Storage	%	100.00%
Degradation Factor (%/yr)	%	0.00%
System Life	Years	15
Efficiency		
AC/AC Efficiency **OR**	%	75%
Energy Charge Ratio	kWin/kWout	-
Output		
Cycles per Year	#	365
Installed Cost		
DC Battery Cost per kWh of usable storage	$/kWh	$426
Total DC Battery Cost	$	$127,735,000
$/kW installed (incl PCS)	$/kW	$516
Total $/kW Cost	$	$25,795,750
Total	$	$153,530,750
Cost per kW	$/kW	$3,071
System Cost - Regional Multiplier	Ratio	1.000
System Cost - Regional Cost	$/kW	$3,071
	$/Useable kWh	$512
Fixed O&M		
Fixed O&M Cost	$/kW-Yr.	$4.5
Periodic Major Maintenance	$/kW	$0
period between maintenance	years	15
Property Tax	% of $/kW capex	1.0%
Insurance Cost	% of $/kW capex	0.5%
Variable O&M		
Variable Costs	$/kWh produced	$0.0005
Charging Costs		
Avg. Charging Cost	$/MWh	$30.00
Fuel Cost	$/MMBtu	$3.00
Fuel Cost Escalation	%	5%
CO2 Emission Rate by Fuel	lb/MMBtu	117
CO2 Allowance Price	$/ton	$30
Heat rate	Btu/kWh	-
Annual Heat Rate Degradation	%	
Fixed O&M Cost - Escalator (%/yr)		2.0%
Variable O&M Cost - Escalator (%/yr)		2.0%
Finance		
Ownership		IOU
Percent Financed with Equity	%	50%
Debt Interest Rate	%	6.00%
After-Tax WACC	%	7.30%
Cost of Equity	%	11.04%
Target average DSCR	ratio	1.40
Debt Term	Years	15

Table B-8. IOU Revenue Requirement Model for 50-MW/6-hour NaS Battery

IOU/POU REVENUE REQUIREMENT MODEL	2011	2012	2013
Usable Storage		300,000	300,000
Cycles		365	365
Energy Production (kWh)		**109,500,000**	**109,500,000**
Total Revenue		**$36,699,178**	**$35,786,439**
Operating Costs			
Charging Costs		($4,380,000)	($4,599,000)
Fuel Costs		$0	$0
CO2 Costs		$0	$0
Periodic Maintenance		$0	$0
Fixed O&M Costs		($224,580)	($229,072)
Variable O&M Cost		($50,000)	($51,000)
Insurance Costs		($767,654)	($783,007)
Property tax		($800,694)	($760,659)
Excise tax		$0	$0
Payment-In-Lieu-Of-Taxes (PILOT) - ($/kW)		$0	$0
Payment-In-Lieu-Of-Taxes (PILOT) - ($/MWh)		$0	$0
Royalty payment to landowner		($71,498)	($71,498)
Gross-receipts tax		$0	$0
Total Costs		**($6,294,425)**	**($6,494,235)**
Operating Profit		**$30,404,753**	**$29,292,204**
Revenue Requirement			
Operating Costs		$6,294,425	$6,494,235
Net Debt Financing Costs		$4,804,161	$4,483,884
Equity Return		$8,843,468	$8,374,016
Depreciation		$10,675,914	$10,675,914
Tax on Equity Return - before grossup		$3,603,360	$3,412,076
ITC		$0	$0
PTC		$0	$0
Tax Grossup		$2,477,849	$2,346,314
Total Revenue Requirement		**$36,699,178**	**$35,786,439**
Capital Cost		160,138,713	160,138,713
Starting Rate Base		160,138,713	151,637,803
Accumulated Deferred Income Tax		2,175,004	9,570,018
Accumulated Depreciation		(10,675,914)	(21,351,828)
Ending Balance Rate Base	$160,138,713	151,637,803	148,356,903
Debt Schedule			
Debt Term Flag		1	1
Beginning Balance		$80,069,357	$74,731,400
Debt Service	($80,069,357)	($10,142,119)	($9,821,841)
Interest		($4,804,161)	($4,483,884)
Principal	($80,069,357)	($5,337,957)	($5,337,957)
Ending Balance	$80,069,357	$74,731,400	$69,393,443
Interest earned on Debt Service Fund		$0	$0
Equity Return			
Beginning Balance		$80,069,357	$75,818,902
Equity Return		($8,843,468)	($8,374,016)
Return of Invested Equity	($80,069,357)	($5,337,957)	($5,337,957)
Book Equity Return		($14,181,425)	($13,711,973)

Table B-9. Levelized and Present Value Cost Metrics for 50-MW/6-hour NaS Battery

	Total		Levelized		Present Value	
	Sum ($)	NPV	$/MWh	$/KW-yr	PV $/kW	PV $/kWh
Fixed Costs	$368,720,593	$234,298,958	$239.40	$524.29	$4,686	$781
Variable Costs	$95,378,779	$53,345,943	$54.51	$119.37	$1,067	$178
Total Costs	**$464,099,373**	**$287,644,901**	**$293.91**	**$643.66**	**$5,753**	**$959**

The annual costs and levelized revenue are summarized in Figure B-2. The installation costs are shown in year zero (2011), with the proportion financed by debt and by equity. The annual equity financing costs include the return of equity and return on equity to shareholders. Similarly, the debt financing includes principal and interest payments on debt. Taxes include all property and income taxes, including deductions for interest payments and depreciation. The operating costs include charging costs, fixed O&M, variable O&M and periodic replacement costs.

The LCOE ($/MWh) is set to provide the target return on equity and results in the positive revenue line at the top of the chart.

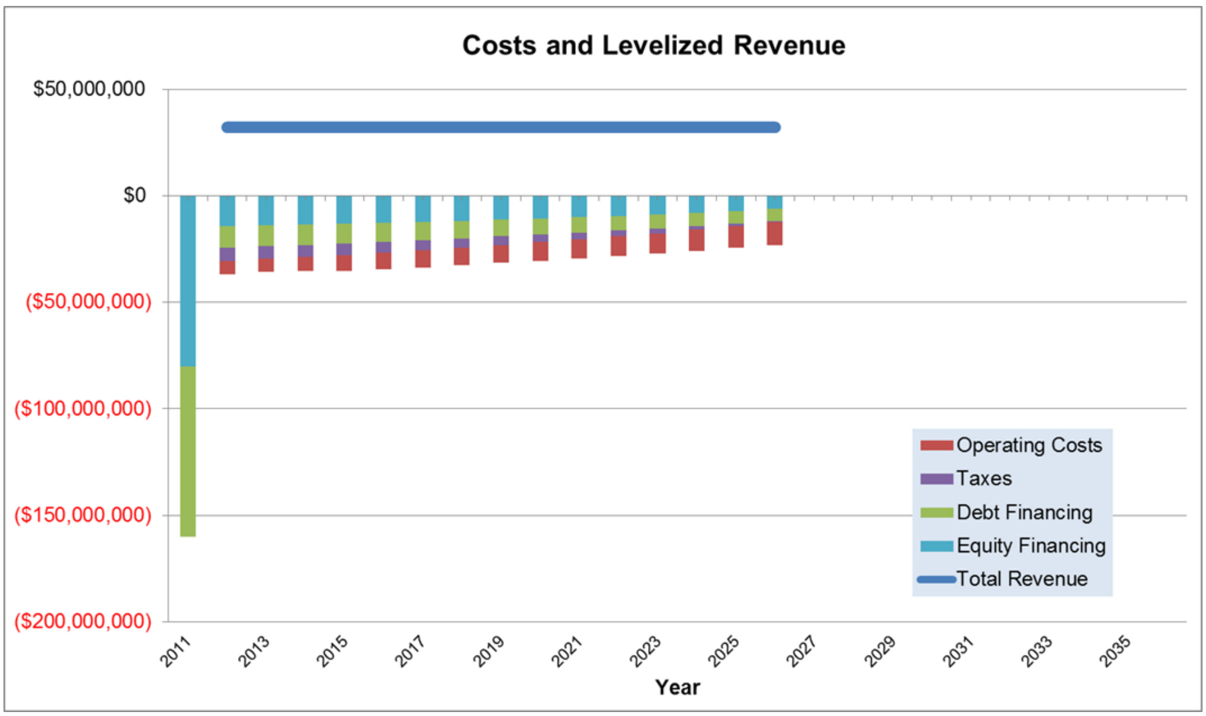


Figure B-2. Annual Costs and Levelized Revenue for 50MW/6-hour NaS Battery

B.2.4 Annual Storage Technology Costs

The primary annual costs for the storage technologies are charging costs (electricity, fuel and CO_2) fixed O&M ($/kW installed), and variable O&M ($kWh discharged). Periodic maintenance, such as module replacement, is also included for some technologies. Additional costs such as insurance and property tax are based on a percentage of total installed costs.

Vendors provide price quotes for their systems with a presumed number of cycles per year. However, the definition of a cycle is not consistent across all vendors. Systems offering 5,000 to 17,000 cycles per year for frequency regulation will provide more frequent shallow cycles than systems offering peaking capacity with 365 full cycles per year. The vendors did not provide O&M costs per cycle, whether deep or shallow, so such distinctions could not be incorporated in this cost analysis. The variable costs for each application are therefore driven solely by the annual quantity of energy discharge required. The annual charging costs are based on the MWh of energy discharged per year and the round-trip efficiency of the storage technology.

For all applications except frequency regulation, annual energy discharged is based on an assumption of a single full cycle per day (365 cycles per year). A 1-MW system with 4 hours of duration would require 1,460 MWh per year of energy discharge (1 MW * 4 hours * 365 days), which equates to a capacity factor of approximately 16% (1,460 MWh/1 MW * 8760 hours per year). With this assumption, longer duration systems will discharge more energy, and therefore require a higher proportion of energy charging per MW of installed capacity (e.g., a higher capacity factor). This results in similar charging costs on a present value $/kWh installed basis, but higher costs on a present value $/kW installed basis for longer duration systems. On the other hand, longer duration systems will presumably also have a greater ability to stack multiple benefit streams and therefore accrue more benefits in a cost-benefit analysis.

Unlike the other applications modeled, frequency regulation is defined more by the capacity (MW) offered than the energy (MWh) discharge required (i.e., mileage). Therefore, rather than assuming the same number of cycles, the frequency regulation analysis assume the same mileage—that is, the quantity of energy discharge per MW of capacity—for each system, independent of duration. A reference case of 5,000 cycles for a 0.25-hour duration battery is used, which equates to a capacity factor of just under 15%. In other words, each MW of installed capacity will discharge 1,250 MWh of energy per year in providing frequency regulation. This approach allows more consistent comparison with equivalent charging and variable O&M costs as a proportion of the MW of discharge capacity. The comparison of technologies providing frequency regulation is limited to shorter duration systems (less than 1.3 hours).

B.3 Comparison with a Combustion Turbine

To validate the model and provide a reference point, both a CT and a CCGT were run through the same spreadsheet model with the same financial assumptions used to calculate the energy storage technology costs. The natural gas price starts at $3.00/MMBtu and escalates at 5% per year. The results are presented in Table B-10 and Table B-11.

Table B-10. Comparable Costs for a Combustion Turbine and Combined-Cycle Gas Turbine

Technology Option	Capacity (MW)	Heat Rate	Capacity Factor	Installed Cost ($/kW)	Present Value Life-cycle Cost ($/kW)	Levelized Cost of Capacity ($/kW-yr)	LCOE ($/MWh)
Combustion Turbine	100	11,000	5%	720	2225	156 (Total) 124 (Fixed Only)	357
Combined-Cycle Gas Turbine	500	6900	80%	1100	5152	498 (Total) 173 (Fixed Only)	71

Table B-11. Inputs for the Combustion Turbine and Combined-Cycle Gas Turbine

COST AND PERFORMANCE DATA		CT	CCGT
System Size			
Charge/Discharge Capacity (kW)	kW	100,000	500,000
Hours of storage at rated capacity	hours	24.00	24.00
Depth of Discharge per cycle	%	100%	100%
Useable Energy Storage Capacity (kWh)	kWh	2,400,000	12,000,000
Installed Energy Storage Capacity	kWh	2,400,000	12,000,000
Useful Life			
End-of-Life Residual Energy Storage	%	100.00%	100.00%
Degradation Factor (%/yr)	%	0.00%	0.00%
System Life	Years	20	20
Efficiency			
AC/AC Efficiency **OR**	%	0%	0%
Energy Charge Ratio	kWin/kWout	0.97	0.97
Output			
Cycles per Year	#	18	292
Installed Cost			
DC Battery Cost per kWh of usable storage	$/kWh	$0	$0
Total DC Battery Cost	$	$0	$0
$/kW installed (incl PCS)	$/kW	$720	$1,100
Total $/kW Cost	$	$72,000,000	$550,000,000
Total	$	$72,000,000	$550,000,000
Cost per kW	$/kW	$720	$1,100
System Cost - Regional Multiplier	Ratio	1.000	1.000
System Cost - Regional Cost	$/kW	$720	$1,100
	$/Useable kWh	$30	$46
Fixed O&M			
Fixed O&M Cost	$/kW-Yr.	$15.8	$8.8
Periodic Major Maintenance	$/kW	$0	$0
period between maintenance	years	4	4
Property Tax	% of $/kW capex	1.0%	0.0%
Insurance Cost	% of $/kW capex	0.5%	0.0%
Variable O&M			
Variable Costs	$/kWh produced	$0.00400	$0.00300

NOTE: CT estimates typical of a frame type turbine with heat rate of 11,000 Btu/kWh for CT and 6.900 Btu/kWh for the CCGT. Simple cycle aero derivative CTs would have higher capital costs and lower heat rates.

The CT is generally viewed as a capacity resource to be used during a limited number of peak hours. The CCGT, on the other hand, is a baseload energy resource. The levelized cost of capacity for the CT, for fixed costs only and for both fixed and variable costs, is $124/kW-yr. and $156/kW-yr., respectively. With a capacity factor of only 5%, the LCOE including both fixed and variable cost is relatively high at $357/MWh. The CCGT has a low LCOE at $71/MWh. The levelized cost of capacity considering fixed costs only is $173/kW-yr. With variable costs also included, the levelized cost of capacity is $498/kW-yr.

One of the first questions often asked about energy storage is how it compares to a CT as a peaking or flexible resource. The CT serves as the proxy or benchmark of choice for a flexible capacity resource. CTs can be started on short notice (approximately 10 minutes) and ramp quickly (approximately 3 MW/minute). This report focuses solely on technology costs. On the cost side, energy storage technology costs range from near to much higher than the cost of a CT on a $/kW installed basis. As discussed above, the relevant levelized cost metric for a CT is capacity ($/kW-yr), not LCOE ($/MWh). With the assumptions used in this appendix, the levelized cost of capacity for all the energy storage technologies are well above the $156/kW-yr. for a CT.

The cost side, however, is only part of the story when comparing storage to a CT. Another important consideration is the operational value of the capacity to the system operator. Many storage technologies offer greater operational flexibility, faster response times, and faster ramp rates than a CT, all of which are of increasing value with increasing penetrations of intermittent renewable resource. How to value storage and fossil capacity on a comparable basis is an area of active study and debate and beyond the scope of this appendix.

Another consideration is the net revenues earned by storage or a CT in energy, ancillary service (AS), and other markets. When calculating the cost or value of capacity, the net revenues (or net margins) earned from other markets are first subtracted from the full cost of the plant. This results in a residual capacity value or Cost of New Entry (CONE). The CONE represents the additional payments needed over and above energy and AS market revenues to provide sufficient incentive for a developer to construct and operate a new plant in the region. These values are used by ISOs such as PJM, NYISO, and CAISO to establish benchmarks for the value of new capacity.

CTs bid into energy and AS markets when it is economical to do so based on their cost of generation, driven primarily by the cost of natural gas. CTs also incur start-up and minimum operating costs to stand ready to provide energy or AS. Because of these costs and because CTs are less efficient (have a high heat rate) compared to CCGTs, CTs generally have a relatively low capacity factor on the order of 5% to 15%.

Many storage technologies do not have such constraints and can reasonably be expected to earn more net revenues than a CT. Storage technologies without minimum operating or stand-by costs will find it more frequently economical to bid into energy and AS markets. Furthermore, a 50-MW CT with a minimum operating level of 10 MW could only offer 20 MW of regulation up and down with a set point of 30 MW (and associated operating costs). In comparison, a similarly sized battery could offer a full 50 MW of regulation up and down at a set point of 0 MW (with minimal operating costs).

The relevant comparison from a cost standpoint is residual capacity value after net revenues for a CT and storage technology have been subtracted. A full analysis of net revenues requires a co-optimized dispatch such as that performed by EPRI's ESVT, which is beyond the scope of this analysis. However an illustrative comparison is shown in Figure B-3. An example CT with a levelized capacity cost of $188/kW-yr. operating in California earns $49/kW-yr. in net revenue in the energy and AS markets (at capacity factor of 9%).[1] This leaves a residual capacity value of $139/kW-yr. An energy storage system has a higher levelized cost, but also higher net revenues. The key question will be: do the higher net revenues for energy storage offset the higher costs to such a degree as to make the residual capacity values comparable

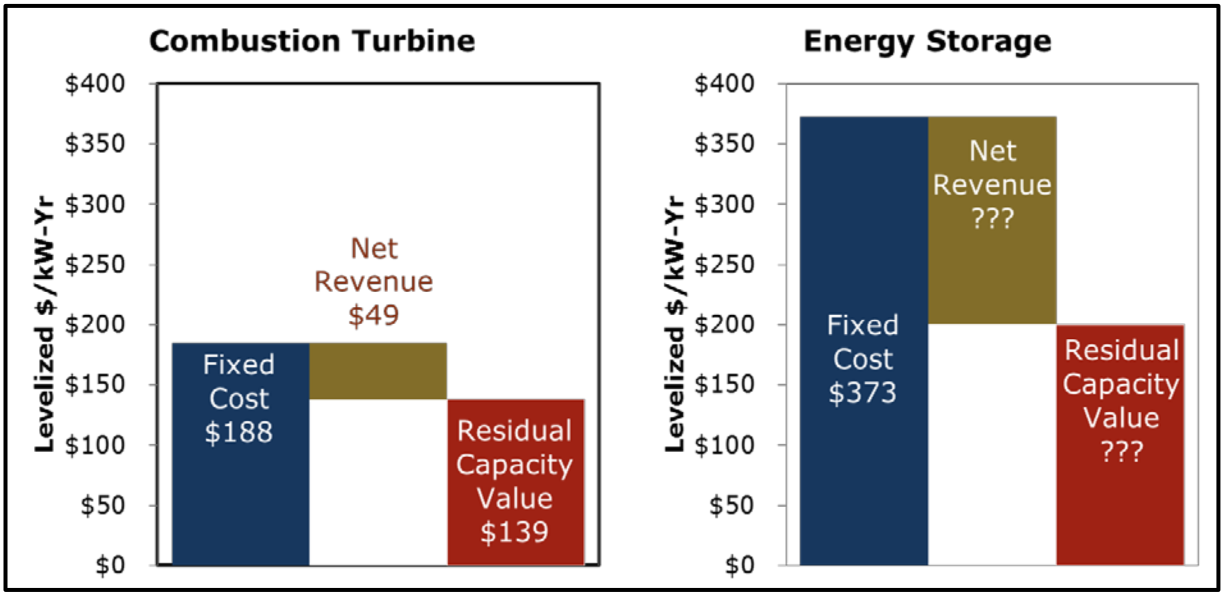


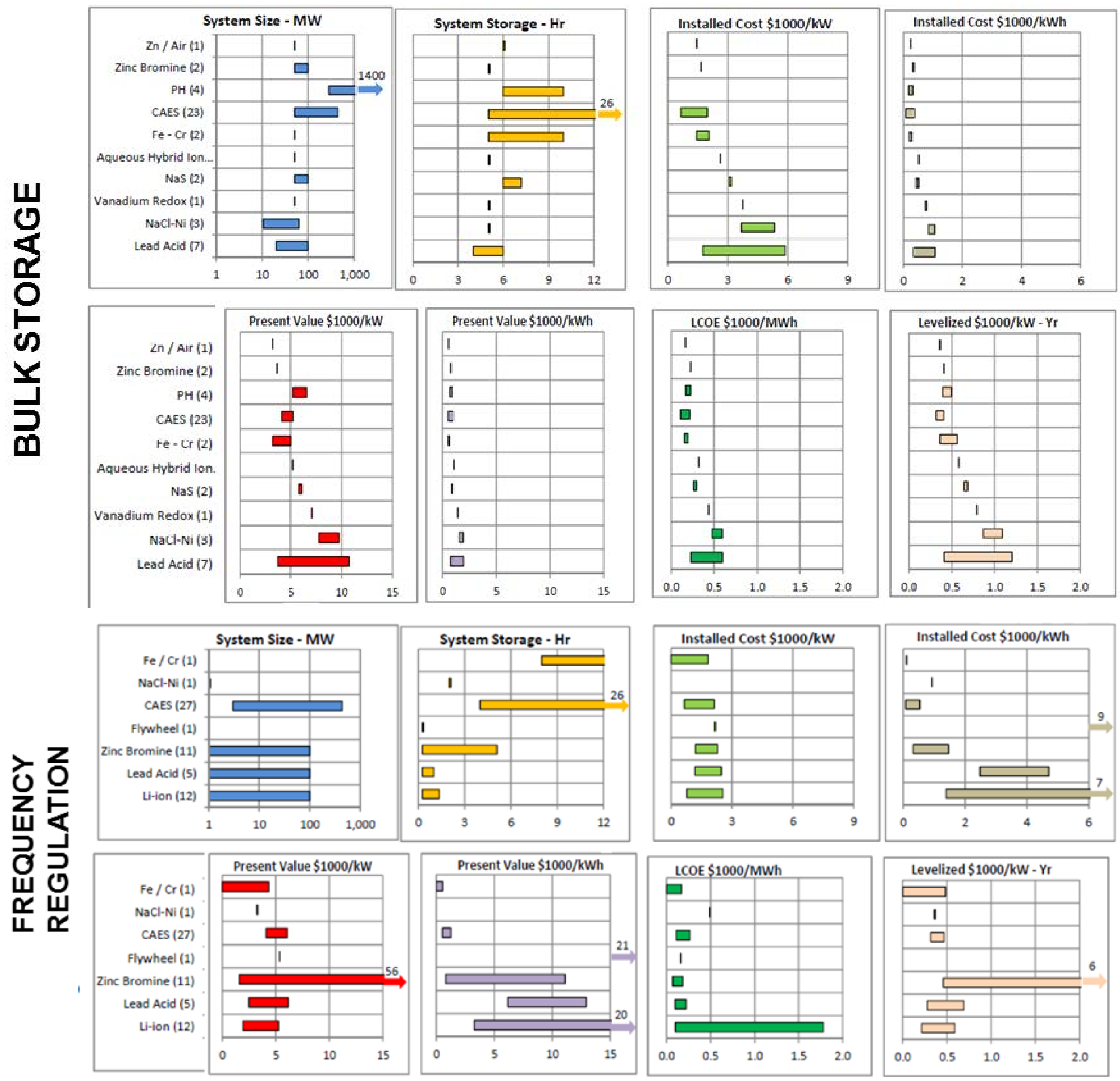
Figure B-3. Illustrative Comparison of CT and Energy Storage Residual Capacity Value Calculation

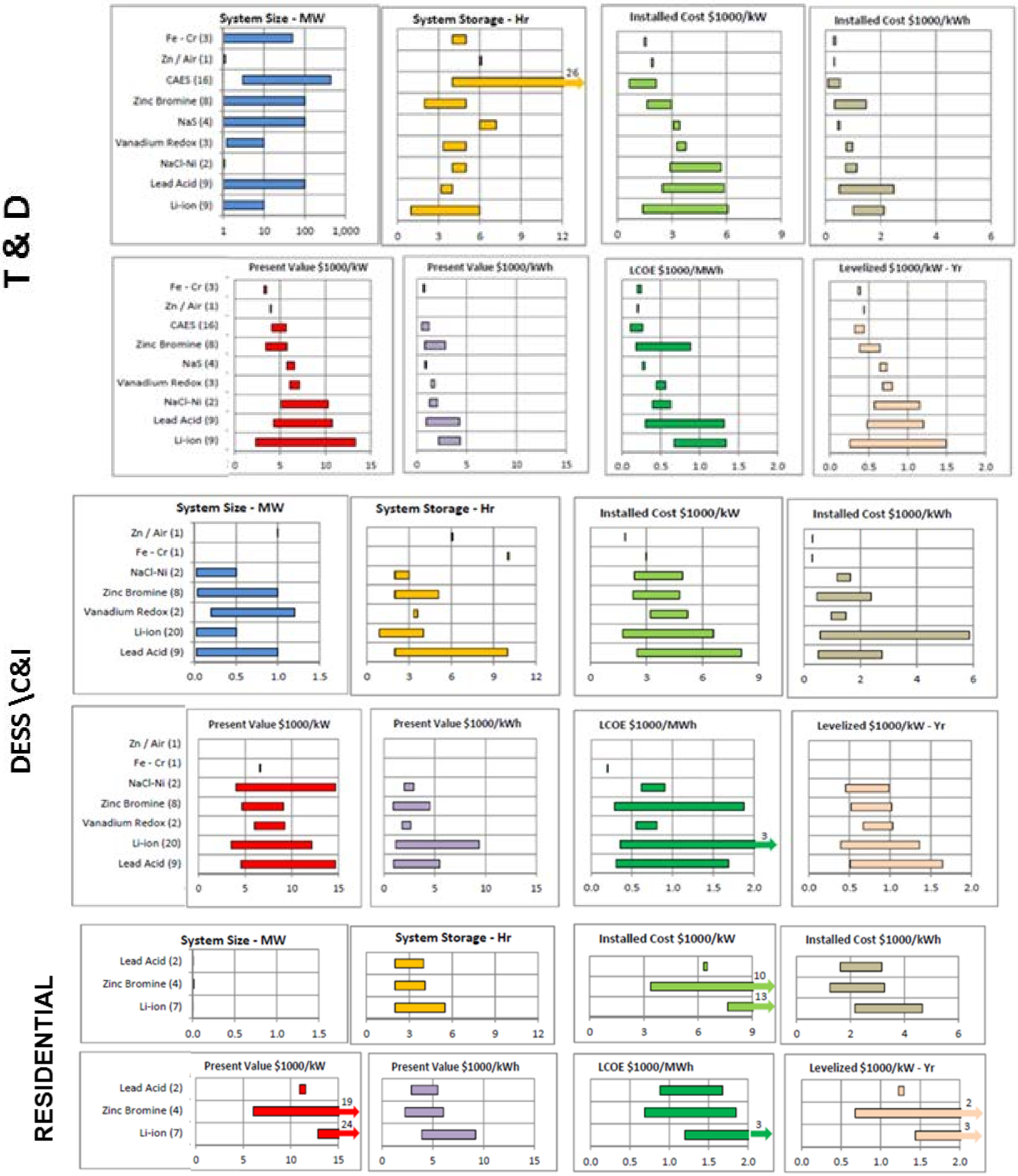
This analysis leaves us with two primary considerations when comparing energy storage to a CT. With respect to cost: how do the residual capacity values (or CONEs) for the two technologies compare? With respect to value: how much additional value does a megawatt of storage have compared to a megawatt of flexible fossil generation?

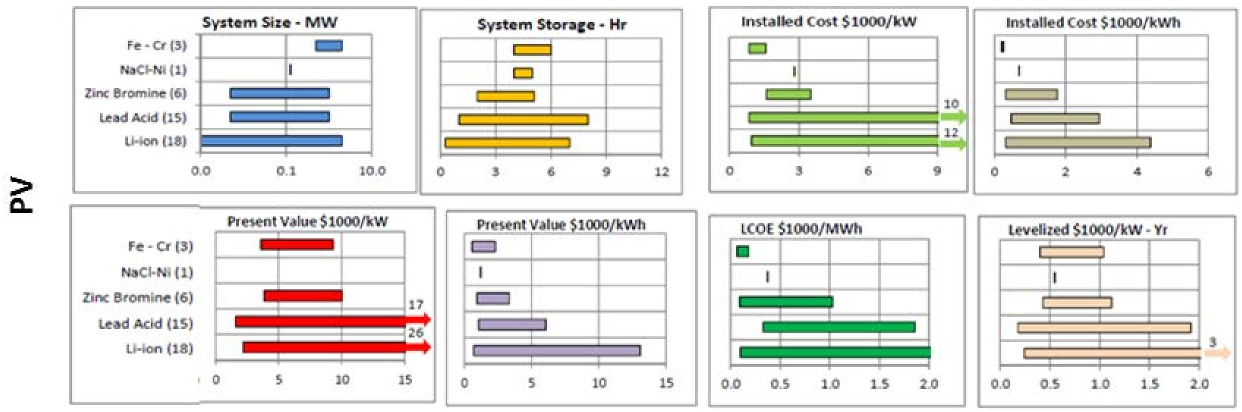
[1] CAISO, 2012.

B.4 Technology Cost Tables

The following mini-charts are organized by service and summarize the detailed information in the tables for each technology which are shown in the sections that follow.




T & D
System Size - MW
Fe - Cr (3)
Zn / Air (1)
CAES (16)
Zinc Bromine (8)
NaS (4)
Vanadium Redox (3)
NaCl-Ni (2)
Lead Acid (9)
Li-ion (9)
System Storage - Hr
26
Installed Cost $1000/kW
Installed Cost $1000/kWh
Present Value $1000/kW
Present Value $1000/kWh
LCOE $1000/MWh
Levelized $1000/kW - Yr
DESS \C&I
System Size - MW
Zn / Air (1)
Fe - Cr (1)
NaCl-Ni (2)
Zinc Bromine (8)
Vanadium Redox (2)
Li-ion (20)
Lead Acid (9)
System Storage - Hr
Installed Cost $1000/kW
Installed Cost $1000/kWh
Present Value $1000/kW
Present Value $1000/kWh
LCOE $1000/MWh
3
Levelized $1000/kW - Yr
RESIDENTIAL
System Size - MW
Lead Acid (2)
Zinc Bromine (4)
Li-ion (7)
System Storage - Hr
Installed Cost $1000/kW
10
13
Installed Cost $1000/kWh
Present Value $1000/kW
19
24
Present Value $1000/kWh
LCOE $1000/MWh
3
Levelized $1000/kW - Yr
2
3



The cost tables on the following pages are organized by technology and show detailed information summarized in the mini-charts above.

B.4.1 Pumped Hydro

Table B-12. Cost Estimates for New Greenfield Pumped Hydro Projects

(Parameters noted in black are vendor inputs.)

Technology Type For Bulk Storage Application	**Pumped Hydro**		**Pumped Hydro**		**Pumped Hydro**		**Pumped Hydro**	
Survey Year	2010		2010		2010		2010	
DESIGN BASIS - General								
Unit Capacity - Net kW	280,000		1,300,000		900,000		1,200,000	
Hours of Energy storage at rated Capacity - hrs	8		9		16		8	
Depth of Discharge (DOD) per cycle	1		1		1		1	
Energy Capacity - kWh @ rated DOD	2,240,000		11,700,000		14,400,000		9,600,000	
Energy Capacity - kWh @ 100% DOD	2,240,000		11,700,000		14,400,000		9,600,000	
Auxiliaries - kW	na							
Unit Size - Net kW	variable		variable		variable		variable	
Number of Units - #	1 - 4		1 - 4		1 - 4		1 - 4	
Physical Size - Unit / SF	< 10 Acres		250 Acres		40 Acres		250 Acres	
Foot Print - SF	40 Acres		250 Acres		40 Acres		250 Acres	
Unit Weight - lbs	NA		NA		NA		NA	
Round Trip AC / AC Efficiency - %	81%		81%		81%		81%	
Number of cycles / year	365		365		365		365	
DESIGN BASIS - Site								
Design Summer Ambient T - ^{o}F	NA		NA		NA		NA	
Design Winter Ambient T - ^{o}F	NA		NA		NA		NA	
GENERAL - Timing								
Plant Life, yrs	60		60		60		60	
TOTAL PLANT COST								
$/kW	$2,500		$1,850		$2,200		$2,700	
$/kWh @ rated DOD	$312.50		$206		$138		$338	
$/kWh @ 100% DOD	NA		NA		NA		NA	
$/kWh Delivered @ rated DOD								
PLANT COST	fixed speed	variable speed	fixed speed	variable speed	fixed speed	variable speed	fixed speed	variable speed
Power - $/kW (all elect/mech equipment including prime mover and balance of plant systems to support unit ops)	$550	$750	$550	$750	$550	$750	$500	$650
Storage - $/kWh @ 6 hours	$156		$103		$69		$169	
Storage - $/kW (construct the physical facility to hold the storage and this cost includes all civil works and water conveyance	900 - 2000		900 - 2000		900 - 2000		900 - 2000	
SYSTEM COSTS - Equipment & Install	$/kW	Actual Cost	$/kW	Actual Cost	$/kW	Actual Cost	$/kW	Actual Cost
Pumped Hydro System								
Pumped Hydro Equipment - included in row 56 above								
Pumped Hydro Installation - included in row 56 above								
Enclosures								
Utility Interconnection								
Equipment								
Installation								
Site BOP Installation (Civil Only) - all site civil and water conveyance costs incl in row 57 above.								
Total Cost Equipment								
Total Cost Installation								
General Contractor Facilities at 15% install								
Engineering Fees @ 5% Install								
Project Contingency Application @ 5% install								
Process Contingency Application @ 5% of battery								
Total Plant Cost (TPC)	$2,500	$700,000,000	$1,850	$2,405,000,000	$2,200	$1,980,000,000	$2,700	$3,240,000,000
OPERATING EXPENSES								
Fixed O&M - $/kW-yr	$8.21		$5.60		$6.13		$6.00	
Periodic Major Maintenance - $/kW	$112		$112		$112		$112	
Period between Major Maintenance - yrs	20		20		20		20	
Variable O&M - $/kWh (Charging or Discharging)	$0.00029		$0.0003		$0.0003		$0.0003	

Notes:

Transmission costs not included and could be substantial as the typical voltage is 500kV.

New stations which use variable speed drives are incrementally higher than fixed speed units.

Projects that have at least one existing reservoir will be on the low end of this civil cost range.

No interconnect costs are included.

Periodic maintenance costs are estimated at $112/kW and include the following major maintenance activities: complete turbine overhaul and disassembly every 10 years; complete generator rewind every 20 years; estimates are based on actual pumped storage operating plants.

B.4.2 CAES

Cost Estimates for CAES Systems

CAES systems sized up to 400 MW to 2000 MW or more are possible, as are underground storage durations of 20 to 30 hours or longer. CAES plants may have heat rates near 3850 Btu/kWh; energy ratios (kWh in/kWh out) can range from 0.68–0.75. Estimates include process and project contingency and costs for nitrogen oxides (NOx) emission-control technology [Selective Catalytic Reduction (SCR)]. A storage cavern with salt geology is assumed; costs for other geologies can vary significantly and are site-specific. Costs for siting, permitting, environmental impact studies, geological assessments, and owner's costs are not included. These cost elements can be very significant. Future system costs may be lower once standard, pre-designed systems are available.

Table B-13 provides reference cost estimates for several CAES plant systems. Data are based on several reference designs from vendors.

Table B-13. Cost Estimates for CAES Systems

Technology Type For Bulk Storage Application	CT-CAES (Below Ground)	CT-CAES (Above Ground)	CT-CAES (Above Ground)	CT-CAES (Above Ground)	BRAYTON-CAES (Below Ground)	BRAYTON-CAES (Below Ground)
Survey Year	2011	2011	2010	2011	2011	2011
System Size	50 MW	50 MW	50 MW	50 MW	103 MW	103 MW
Storage Capacity (Hours)	8-26	5	5	5	8-20	8-20
Supplier	**S12**	**S12 - 2**	**S0**	**S12 - 1**	**S9 - 1**	**S9 - 2**
DESIGN BASIS - General						
Minimum storage pressure for full generation capability - psia @ surface	~ 400-800	~ 400-800		~ 400-800	315	315
Maximum compression discharge pressure - psia @ surface	~ 1500-2000	~ 1500-2000		~ 1500-2000	515	515
Storage type - above or below ground	Salt Dome, Aquifer or Hard Rock	Above Ground		Above Ground	Shallow aquifer	Shallow aquifer
Unit Net Capacity - MW @ 95F ambient	50.0	50.0	50	50.0	103	103
Combustion Turbine Capacity - MW, if applicable	19.2	19.2	24	19.5	103	103
Air Expander(s) Total Net Capacity - MW	30.8	30.8	26	30.5		
CAES Energy Stored/Released/Generated based on 8 hrs generation (or 2 hours for above ground air storage) - MWH	304 / 400	124 / 250 (5 hours	250, for a 5 hour storage plant	190 / 250 (5 hours	823.8 MWh	826.5 MWh
More Storage -- CAES Energy Stored/ Released/ Generated based on 20 hrs generation (or 4 hours for above ground air storage) - MWH	988 / 1300	N/A		N/A	2,059 MWh	2,066.2 MWh
Round Trip AC / AC Efficiency - %						
Energy Charge Ratio - kWh in/kWh out @ Full Load	0.70	0.45	0.8	0.70	0.74	0.74
Number of cycles / year	365	365	365	365	365	365
CAES Plant unit Net Heat Rate @ Full Load - Btu/kwh (LHV)	3,900	5,880	4,091	3,900	3,916	3,901
Total Compressors Power - MW. Compressors number are optimized to meet "smart" grid requirements.	19.0	Jan-00	23	Jan-00	76470 kW (based on 415 psia mean	76150 kW (based on 415 psia mean
Hours of Energy storage at Rated Capacity shown - hrs	8.0	5.0	5	5.0	8.0	8
More Storage -- CAES Energy Stored/Released - kWH based on 20 hrs storage for underground	1,300,000	N/A		N/A	2,059,400	2,066,500
Storage Efficiency (Energy Generated/Energy Stored); Inverse of Energy Ratio - %	>90%	>90%	See Heat Rate and Energy Ratio	>90%	1.346	1.357
DESIGN BASIS - Site						
Design Summer Ambient T - ^{o}F	95F	95F		95F	60	60
Design Winter Ambient T - ^{o}F	Not Limited	Not Limited		Not Limited		
GENERAL - Timing						
Month $ for Input Data	9	9	9	9		
Plant Life - yrs	40	40	35	40	40	40
Pre-construction Time - yrs						
TOTAL PLANT COST						
$/kW	$1,210	$1,762	$1,950	$1,958	$1,040	$1,053
$/kWh @ rated DOD	$151	$352	$390	$392	$130	$132
$/kWh @ 100% DOD	$151	$352	$390	$392	$130	$132
TOTAL PLANT COST (More Storage)						
$/Kw (20 or 26 hours underground storage)	$1,359				$1,129	$1,142
$/kWh @ rated DOD	N/A				N/A	N/A
$/kWh @ 100% DOD	$52				$56	$57
PLANT COST						
Power - $/kW	$1,078	$1,188	$1,131	$1,078	$921	$934
Storage - $/kWh @ 8 hours underground, varies above ground	$17	$115	$164	$176	$15	$15
Storage - $/kWh @ 20 or 26 hours	$11	N/A	N/A	N/A	$10	$10
Incremental Cost for each hour of storage - $/kW-hour						
SYSTEM COSTS - Equipment & Install						
CAES Capital Costs						
Power Plant Cost Excluding Storage	$49,000,000	$54,000,000	$56,550,000	$49,000,000	$56,118,650	$57,655,350
BOP equipment and installation	included	included	included	included	$35,215,740	$35,337,150
Compressed Air Storage Cost	$6,000,000	$26,105,300	$40,950,000	$40,000,000	$11,120,760	$11,159,100
Total CAES Plant Cost	55,000,000	80,105,300	$88,636,364	89,000,000	102,455,150	104,151,600
Total CAES Plant Cost w/ 10% Contingency of BOP and Storage	$60,500,000	$88,115,830	$97,500,000	$97,900,000	$107,088,800	$108,801,225
CAES TPC ($/KW) (8 hours underground storage)	$1,210	$1,762	$1,950	$1,958	$1,040	$1,053
Capital Costs More Storage)						
Power Plant Cost Excluding Storage	$49,000,000				$91,334,390	$92,992,500
Compressed Air Storage Cost	$12,750,000				$19,461,330	$19,528,425
Total CAES Plant Cost w/ 10% Contingency	$67,925,000				$116,263,427	$118,007,483
CAES TPC ($/KW) (20 or 26 hours underground storage)	$1,359				$1,129	$1,142
Total Plant Cost (TPC)	$60,500,000	$88,115,830	$97,500,000	$97,900,000	$107,088,800	$108,801,225
OPERATING EXPENSES						
Fixed O&M - $/kW-yr	$3	$3	$4	$3	$5	$5
Periodic Major Maintenance - $/kW	$90	$90	$90	$90	$90	$90
Period between Major Maintenance - yrs	4	7	7	7	4	4
Variable O&M - $/kWh (Charging or Discharging)	$0.0030	$0.0030	$0.0040	$0.0030	$0.0035	$0.0035

Table B-13. Cost Estimates for CAES Systems (continued)

Technology Type For Bulk Storage Application	BRAYTON-CAES (Below Ground)	BRAYTON-CAES (Below Ground)	CT-CAES (Below Ground)	CT-CAES (Below Ground)	CT-CAES (Below Ground)	BRAYTON-CAES (Below Ground)	CT-CAES (Below Ground)
Survey Year	2011	2011	2011	2011	2011	2011	2011
System Size	136 MW	136 MW	183 MW	236 MW	322 MW	408 MW	441 MW
Storage Capacity (Hours)	8-20	8-20	8-26	8-26	8-26	8-20	8-26
Supplier	**S9 - 1**	**S9 - 2**	**S12**	**S12**	**S12**	**S9**	**S12**
DESIGN BASIS - General							
Minimum storage pressure for full generation capability - psia @ surface	900	900	~ 400-800	~ 400-800	~ 400-800	900	~ 400-800
Maximum compression discharge pressure - psia @ surface	1200	1200	~ 1500-2000	~ 1500-2000	~ 1500-2000	1200	~ 1500-2000
Storage type - above or below ground	Salt, hard rock, deep aquifer	Salt, hard rock, deep aquifer	Salt Dome, Aquifer or Hard Rock	Salt Dome, Aquifer or Hard Rock	Salt Dome, Aquifer or Hard Rock	salt, hard rock, deep aquifer	Salt Dome, Aquifer or Hard Rock
Unit Net Capacity - MW @ 95F ambient	136	136	182.7	236.0	321.8	408	441.0
Combustion Turbine Capacity - MW, if applicable	136	136	65.3	86.0	122.2	408	174.0
Air Expander(s) Total Net Capacity - MW			117.4	150.0	199.5		267.0
CAES Energy Stored/Released/Generated based on 8 hrs generation (or 2 hours for above ground air storage) - MWH	1,085 MWh	1,088 MWh	1168 / 1462	1422 / 1888	1838 / 2574	3,264 MWh	2528 / 3528
<u>More Storage</u> -- CAES Energy Stored/ Released/ Generated based on 20 hrs generation (or 4 hours for above ground air storage) - MWH	2,712 MWh	2,720 MWh	3796 / 4750	4623 / 6136	5975 / 8367	8,160 MWh	8216 / 11466
Round Trip AC / AC Efficiency - %							
Energy Charge Ratio - kWh in/kWh out @ Full Load	0.75	0.74	0.70	0.70	0.70	0.74	0.70
Number of cycles / year	365	365	365	365	365	365	365
CAES Plant unit Net Heat Rate @ Full Load - Btu/kwh (LHV)	3,857	3,847	3,847	3,770	3,784	3,847	3,760
Total Compressors Power - MW. Compressors number are optimized to meet "smart" grid requirements.	101592 kW (based on 1050	101272 kW (based on 1050	73.0	88.9	114.9	303816 kW (based on 1050	158.0
Hours of Energy storage at Rated Capacity shown - hrs	8.0	8.0	8	8.0	8.0	8	8.0
<u>More Storage</u> -- CAES Energy Stored/Released - kWH based on 20 hrs storage for underground	2,712,400	2,720,000	4,750,200	6,136,000	8,366,280	8,160,000	11,466,000
Storage Efficiency (Energy Generated/Energy Stored); Inverse of Energy Ratio - %	1.335	1.344	>90%	>90%	>90%	1.344	>90%
DESIGN BASIS - Site							
Design Summer Ambient T - ^{o}F	60	60	95F	95F	95F	60	95F
Design Winter Ambient T - ^{o}F			Not Limited	Not Limited	Not Limited		Not Limited
GENERAL - Timing							
Month $ for Input Data			9	9	9		9
Plant Life - yrs	40	40	40	40	40	40	40
Pre-construction Time - yrs							
TOTAL PLANT COST							
$/kW	$1,050	$1,065	$957	$997	$769	$787	$656
$/kWh @ rated DOD	$131	$133	$120	$125	$96	$98	$82
$/kWh @ 100% DOD	$131	$133	$120	$125	$96	$98	$82
TOTAL PLANT COST (More Storage)							
$/Kw (20 or 26 hours underground storage)	$1,149	$1,164	$1,106	$1,144	$919	$886	$805
$/kWh @ rated DOD	N/A	N/A	N/A	N/A	N/A	N/A	N/A
$/kWh @ 100% DOD	$57	$58	$43	$44	$35	$44	$31
PLANT COST							
Power - $/kW	$918	$933	$825	$867	$636	$655	$524
Storage - $/kWh @ 8 hours underground, varies above ground	$17	$17	$17	$16	$17	$17	$17
Storage - $/kWh @ 20 or 26 hours	$12	$12	$11	$11	$11	$12	$11
Incremental Cost for each hour of storage - $/kW-hour							
SYSTEM COSTS - Equipment & Install							
CAES Capital Costs							
Power Plant Cost Excluding Storage	$67,810,000	$70,040,000	$137,000,000	$186,000,000	$186,000,000	$186,300,000	$210,000,000
BOP equipment and installation	$51,535,600	$51,680,000	included	included	included	$73,440,000	included
Compressed Air Storage Cost	$16,274,400	$16,320,000	$22,000,000	$28,000,000	$39,000,000	$48,960,000	$53,000,000
Total CAES Plant Cost	135,620,000	138,040,000	159,000,000	214,000,000	225,000,000	308,700,000	263,000,000
Total CAES Plant Cost w/ 10% Contingency of BOP and Storage	$142,401,000	$144,840,000	$174,900,000	$235,400,000	$247,500,000	$320,940,000	$289,300,000
CAES TPC ($/KW) (8 hours underground storage)	$1,050	$1,065	$957	$997	$769	$787	$656
Capital Costs <u>(More Storage)</u>							
Power Plant Cost Excluding Storage	$119,345,600	$121,720,000	$137,000,000	$186,000,000	$186,000,000	$259,740,000	$210,000,000
Compressed Air Storage Cost	$28,480,200	$28,560,000	$46,750,000	$59,500,000	$82,875,000	$85,680,000	$112,625,000
Total CAES Plant Cost w/ 10% Contingency	$155,827,380	$158,304,000	$202,125,000	$270,050,000	$295,762,500	$361,332,000	$354,887,500
CAES TPC ($/KW) (20 or 26 hours underground storage)	$1,149	$1,164	$1,106	$1,144	$919	$886	$805
Total Plant Cost (TPC)	$142,401,000	$144,840,000	$174,900,000	$235,400,000	$247,500,000	$320,940,000	$289,300,000
OPERATING EXPENSES							
Fixed O&M - $/kW-yr	$5	$5	$3	$3	$3	$5	$3
Periodic Major Maintenance - $/kW	$90	$90	$90	$90	$90	$90	$90
Period between Major Maintenance - yrs	4	4	4	4	4	4	4
Variable O&M - $/kWh (Charging or Discharging)	$0.0035	$0.0035	$0.0030	$0.0030	$0.0030	$0.0035	$0.0030

Notes: Total plant cost (TPC) assumes a conditioned site with all utilities available to the plant and no site-specific costs such as roads, fencing, and site prep. Cost allowances for substation and utility interface are assumed to be included, as well as engineering and project and process contingencies in the TPC. Cost allowances for substation and utility interface are included, as well as engineering and project and process contingencies in the TPC. Cost adjustments, to account for greater hours of storage capacity and increased underground storage volume beyond the minimum ranges listed, are a small portion of the TPC and are dependent on geology of the site.

B.4.3 Sodium Sulphur Battery

Table B-14. Performance, Design, and Cost of NaS Systems

(Parameters noted in black are vendor inputs.)

Application	**Bulk Storage**	**Bulk Storage**	**Utility T&D**	**Utility T&D**
Technology Type	**NaS**	**NaS**	**NaS**	**NaS**
Supplier	**S36**	**S36**	**S36**	**S36**
Survey Year	2010	2010	2010	2010
DESIGN BASIS - General				
System Capacity - Net kW	50,000	100,000	1,000	12,000
Hours of Energy storage at rated Capacity - hrs	6	7.2	7.2	7.2
Depth of Discharge (DOD) per cycle - %	80%	80%	80%	80%
Energy Capacity - kWh @ rated DOD	300,000	720,000	7,200	86,400
Energy Capacity - kWh @ 100% DOD	375,000	900,000	9,000	108,000
Auxiliaries - kW		0	0	0
Unit Size - Net kW	50	100	1	12
Number of Units - #	50	100	1	12
Physical Size - SF/Unit			168	
System Foot Print - SF	100,000	200,000	2,090	25,080
System Weight - lbs	3,500,000	7,000,000	70,000	840,000
Round Trip AC / AC Efficiency - %	75%	75%	75%	75%
Number of cycles / year	365	365	365	365
GENERAL - Timing				
Commercial Order Date				
Plant Life, yrs	15	15	15	15
TOTAL PLANT COST				
$/kW	$3,071	$3,168	$3,434	$3,152
$/kWh @ rated DOD	$512	$440	$477	$438
$/kWh @ 100% DOD	$409	$352	$382	$350
PLANT CAPITAL COST				
Power - $/kW	$516	$490	$757	$474
Storage - $/kWh @ rated DOD	$426	$372	$372	$372
SYSTEM COSTS - Equipment & Install	Projected Cost	Projected Cost	Projected Cost	Projected Cost
ES System				
ES Equipment	$110,000,000	$230,000,000	$2,300,000	$27,600,000
ES Installation	$17,600,000	$37,500,000	$375,000	$4,500,000
Enclosures	included	included	included	included
Owner Interconnection				
Equipment	$9,981,500	$18,893,500	$367,000	$2,288,500
Installation	$1,247,500	$2,361,500	$92,000	$572,000
Enclosures	Included	included	Included	Included
System Packing	included	included	included	included
System Shipping to US Port	$135,000	$270,600	$2,706	$32,472
Utility Interconnection				
Equipment	$3,875,000	$6,875,000	$80,400	$695,000
Installation	$3,875,000	$6,875,000	$80,400	$695,000
Site BOP Installation (Civil Only)	included	included	included	included
Total Cost Equipment	$123,991,500	$256,039,100	$2,750,106	$30,615,972
Total Cost Installation	$22,722,500	$46,736,500	$547,400	$5,767,000
General Contractor Facilities at 15% install	$3,408,375	$7,010,475	$82,110	$865,050
Engineering Fees @ 5% Install	$1,136,125	$2,336,825	$27,370	$288,350
Project Contingency Application @ 0-15% install	$2,272,250	$4,673,650	$27,370	$288,350
Process Contingency Application @ 0-15% of battery	$0	$0	$0	$0
Total Plant Cost (TPC)	$153,530,750	$316,796,550	$3,434,356	$37,824,722
OPERATING EXPENSES				
FIXED O&M - $/kW-yr	$4.5	$4.3	$9.2	$4.8
Replacement Battery Costs - $/kW	$0	$0	$0	$0
Battery replacement - yrs	15	15	15	15
Variable O&M - $/kWh (Charging or Discharging)	0.0005	0.0004	0.0008	0.0004

B.4.4 Sodium-nickel-chloride Battery

Data sheets for several references systems are provided in Table B-15.

Table B-15. Cost and Performance of Sodium-nickel-chloride Battery Systems
(Parameters noted in black are vendor inputs.)

Application	**Bulk Storage**	**Bulk Storage**	**Bulk Storage**	**FR & RI**	**Utility T&D**	**Utility T&D**	**DESS**	**Commerical & Industrial**
Technology Type	**Sodium Metal Halide**	**Sodium Metal Halide**	**Sodium Metal Halide**	**Sodium Metal Halide**	**Sodium Metal Halide**	**Sodium Metal Halide**	**Sodium - Metal Halide**	**Sodium Metal Halide**
Supplier	**S16**	**S16**	**S17**	**S17**	**S16**	**S17**	**S16**	**S17**
Survey Year	2011	2011	2011	2011	2011	2011	2011	2011
DESIGN BASIS - General								
System Capacity - Net kW	10,600.0	53,000.0	50,000	1,000	1,060.0	1,000	26.7	500
Hours of Energy storage at rated Capacity - hrs	5	5	5	2	5	4	3	2
Depth of Discharge (DOD) per cycle - %	85%	85%	80%	80%	85%	80%	85%	80%
Energy Capacity - kWh @ rated DOD	53,000	265,000	250,000	2,000	5,300	4,000	80	1,000
Energy Capacity - kWh @ 100% DOD	62,275.0	311,375.0	312,500	2,600	6,227.5	5,200	94.0	1,250
Auxiliaries - kW	2120	10600	0	0	212	0	3.2	0
Unit Size - Net kW	10600	53000	1000	1000	901	1000	26.7	500
Number of Units - #	2650	13250	50	1	265	1	4	1
Physical Size - SF/Unit	5	5	1,200	413	5.18	350	5	350
System Foot Print - SF	5152	25762	60,000	588	1030	588	8	588
System Weight - lbs	1,291,345	6,456,725	7,500,000	80,000	129,135	150,000	1,949	
Round Trip AC / AC Efficiency - %	88%	88%	86%	86%	88%	86%	84%	84%
Number of cycles / year	365	365	365	365	365	365	365	365
GENERAL - Timing								
Commercial Order Date	3° quarter 2012	3° quarter 2012	Q1 2012	Q1 2012	1° quarter 2012	Q1 2012	1° quarter 2012	Q1 2012
Plant Life, yrs	15	15	15	15	15	15	15	15
TOTAL PLANT COST								
$/kW	$5,334	$4,306	$2,823	$1,846	$5,676	$2,907	$4,941	$2,360
$/kWh @ rated DOD	$1,067	$861	$565	$923	$1,135	$727	$1,647	$1,180
$/kWh @ 100% DOD	$908	$733	$452	$710	$966	$559	$1,402	$944
PLANT CAPITAL COST								
Power - $/kW	$482	$427	$487	$800	$718	$814	$1,869	$1,354
Storage - $/kWh @ rated DOD	$970	$776	$467	$523	$992	$523	$1,024	$503
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost
ES System								
ES Equipment	$45,460,750	$181,843,000	$101,562,500	$910,000	$4,546,075	$1,820,000	$68,620	$437,500
ES Installation	$1,363,823	$5,455,290	$5,078,125	$45,500	$227,304	$91,000	$3,431	$21,875
Enclosures	$187,484	$929,418	$2,162,000	$40,064	$39,097	$40,064	$2,350	$40,064
Owner Interconnection								
Equipment	$2,288,500	$9,981,500	$9,981,500	$367,000	$367,000	$367,000	$31,000	$233,500
Installation	$572,000	$1,247,500	$1,247,500	$92,000	$92,000	$92,000	$15,500	$58,500
Enclosures	Included	Included	Included	Included	Inlcuded	Included	Inlcuded	Included
System Packing	Inlcuded	Inlcuded	$0	$0	Inlcuded	$0	Inlcuded	$0
System Shipping to US Port	$61,146	$135,880	$0	$0	$27,176	$0	$3,000	$0
Utility Interconnection								
Equipment	$695,000	$3,875,000	$3,875,000	$80,000	$80,400	$80,400	$250	$70,400
Installation	$695,000	$3,875,000	$3,875,000	$80,000	$80,400	$80,400	$250	$70,400
Site BOP Installation (Civil Only)	$10,305	$51,523	$120,000	$58,000	$2,061	$58,000	$500	$58,000
Total Cost Equipment	$48,692,880	$196,764,798	$117,581,000	$1,397,064	$5,059,747	$2,307,464	$105,220	$781,464
Total Cost Installation	$2,641,127	$10,629,313	$10,320,625	$275,500	$401,765	$321,400	$19,681	$208,775
General Contractor Facilities at 15% install	$396,169	$1,594,397	$1,548,094	$41,325	$60,265	$48,210	$0	$31,316
Engineering Fees @ 5% Install	$132,056	$531,466	$516,031	$13,775	$20,088	$16,070	$0	$10,439
Project Contingency Application @ 0-15% install	$132,056	$531,466	$1,032,063	$27,550	$20,088	$32,140	$0	$104,388
Process Contingency Application @ 0-15% of battery	$4,546,075	$18,184,300	$10,156,250	$91,000	$454,608	$182,000	$6,862	$43,750
Total Plant Cost (TPC)	**$56,540,364**	**$228,235,740**	**$141,154,063**	**$1,846,214**	**$6,016,561**	**$2,907,284**	**$131,763**	**$1,180,132**
OPERATING EXPENSES								
FIXED O&M - $/kW-yr	$5.4	$4.2	$4.5	$9.2	$8.7	$9.2	$34.9	$11.7
Replacement Battery Costs - $/kW	$1,287	$1,029	$0	$273	$1,287	$0	$772	$0
Battery replacement - yrs	8	8	15	15	8	15	8	15
Variable O&M - $/kWh (Charging or Discharging)	0.0005	0.0005	0.0005	0.0027	0.0011	0.0014	0.0018	0.0027

B.4.5 Vanadium Redox Battery

Performance and Cost Characteristics

Data sheets for several vanadium system reference designs are provided in Table B-16.

Table B-16. Cost and Performance of Vanadium Redox Battery Systems
(Parameters noted in black are vendor inputs.)

Application	**Bulk Storage**	**Utility T&D**	**Utility T&D**	**Commerical & Industrial**	**Commerical & Industrial**
Technology Type	**Vanadium Redox**	**Vanadium Redox**	**Vanadium Redox**	**Vanadium Redox**	**Vanadium Redox**
Supplier	**S32**	**S32**	**S32**	**S32**	**S32**
Survey Year	2011	2011	2011	2011	2011
DESIGN BASIS - General					
System Capacity - Net kW	50000	10000	10000	200	1200
Hours of Energy storage at rated Capacity - hrs	5	4	5	3.5	3.33
Depth of Discharge (DOD) per cycle - %	100%	100%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	250,000	40000	50000	700	3996
Energy Capacity - kWh @ 100% DOD	250,000	40000	50000	700	3996
Auxiliaries - kW	3375	675kW	675kW	17.5kW	
Unit Size - Net kW	250	250	250	200	200
Number of Units - #	200	40	40	1	5
Physical Size - SF/Unit	integrated	200	200	220	220
System Foot Print - SF	101,850	20,000	20,370	356	2037
System Weight - lbs	24,750,000	9,800,000	10,980,000	32000	32000
Round Trip AC / AC Efficiency - %	75%	72%	72%	68%	68%
Number of cycles / year	365	365	365	365	365
GENERAL - Timing					
Commercial Order Date	Late 2011				
Plant Life, yrs	15	15	15	15	15
TOTAL PLANT COST					
$/kW	$3,734	$3,335	$3,756	$5,213	$3,203
$/kWh @ rated DOD	$747	$834	$751	$1,490	$962
$/kWh @ 100% DOD	$747	$834	$751	$1,490	$962
PLANT CAPITAL COST					
Power - $/kW	$635	$656	$657	$2,133	$706
Storage - $/kWh @ rated DOD	$620	$670	$620	$880	$750
SYSTEM COSTS - Equipment & Install	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost
ES System					
ES Equipment	$124,380,000	$20,876,000	$24,876,000	$480,000	$2,458,571
ES Installation	$24,350,000	$4,870,000	$4,870,000	$112,000	$415,000
Enclosures	$3,668,600	$722,000	$735,320	$30,048	$75,332
Owner Interconnection					
Equipment	$9,981,500	$2,288,500	$2,288,500	$131,500	$367,000
Installation	$1,247,500	$572,000	$572,000	$33,000	$92,000
Enclosures	Included	inlcuded	Included	inlcuded	included
System Packing	$0	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$0	$0	$0
Utility Interconnection					
Equipment	$3,875,000	$695,000	$695,000	$62,900	$80,400
Installation	$3,875,000	$695,000	$695,000	$62,900	$80,400
Site BOP Installation (Civil Only)	$203,700	$40,000	$40,740	$43,500	$4,074
Total Cost Equipment	$141,905,100	$24,581,500	$28,594,820	$704,448	$2,981,303
Total Cost Installation	$29,676,200	$6,177,000	$6,177,740	$251,400	$591,474
General Contractor Facilities at 15% install	$4,451,430	$926,550	$926,661	$37,710	$88,721
Engineering Fees @ 5% Install	$1,483,810	$308,850	$308,887	$12,570	$29,574
Project Contingency Application @ 0-15% install	$2,967,620	$308,850	$308,887	$12,570	$29,574
Process Contingency Application @ 0-15% of battery	$6,219,000	$1,043,800	$1,243,800	$24,000	$122,929
Total Plant Cost (TPC)	$186,703,160	$33,346,550	$37,560,795	$1,042,698	$3,843,574
OPERATING EXPENSES					
FIXED O&M - $/kW-yr	$4.5	$5.7	$5.7	$16.5	$7.7
Replacement Battery Costs - $/kW	$746	$626	$746	$720	$615
Battery replacement - yrs	8.0	8.0	8.0	8.0	8
Variable O&M - $/kWh (Charging or Discharging)	0.0005	0.0014	0.0011	0.0016	0.0016

B.4.6 Iron-chromium Battery

Performance and Design Characteristics

Table B-17 provides sample data sheets for conceptual systems by application shown.

Table B-17. Cost and Performance of Iron-chromium Systems
(Parameters noted in black are vendor inputs.)

Application	**Bulk Storage**	**Bulk Storage**	**PV Integration**	**Wind Integration**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Commercial & Industrial /**
Technology Type	**Fe / Cr**	**Fe / Cr**	**Fe / Cr**	**Fe / Cr**	**Fe / Cr**	**Fe / Cr**	**Fe / Cr**	**Fe / Cr**
Supplier	**S14**	**S14**	**S14**	**S14**	**S14**	**S14**	**S14**	**S14**
Survey Year	2011	2011	2011	2011	2011	2011	2011	2010
DESIGN BASIS - General								
System Capacity - Net kW	50,000	50,000	2,000	100,000	1,000	10,000	50,000	500
Hours of Energy storage at rated Capacity - hrs	5	10	4	8	4	5	5	10
Depth of Discharge (DOD) per cycle - %	100%	100%	100%	100%	100%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	250,000	500,000	8,000	800,000	4,000	50,000	250,000	5,000
Energy Capacity - kWh @ 100% DOD	250,000	500,000	8,000	800,000	4,000	50,000	250,000	5,000
Auxiliaries - kW	250	250	10	500	5	50	250	3
Unit Size - Net kW	10,000	10,000	250	10,000	250	10,000	10,000	250
Number of Units - #	5	5	8	10	4	1	5	2
Physical Size - SF/Unit	42,625	54,250	360	47,000	360	42,625	42,625	700
System Foot Print - SF	222,000	283,000	2,880	245,000	1,440	42,625	222,000	1,400
System Weight - lbs	6,800 metric tons	13,610 metric tons	138 metric tons	10,900 metric	138 metric tons	6,800 metric tons	6,800 metric tons	344 metric tons
Round Trip AC / AC Efficiency - %	75%	75%	75%	75%	75%	75%	75%	75%
Number of cycles / year	365	365	4000	365	365	365	365	365
GENERAL - Timing								
Commercial Order Date								
Plant Life, yrs	15	15	15	15	15	15	15	15
TOTAL PLANT COST								
$/kW	$1,427	$2,045	$840	$1,820	$1,517	$1,596	$1,473	$2,984
$/kWh @ rated DOD	$285	$205	$210	$228	$379	$319	$295	$298
$/kWh @ 100% DOD	$285	$205	$210	$228	$379	$319	$295	$298
PLANT CAPITAL COST								
Power - $/kW	$455	$485	$25	$437	$701	$552	$501	$1,178
Storage - $/kWh @ rated DOD	$194	$156	$204	$173	$204	$209	$194	$181
SYSTEM COSTS - Equipment & Install	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Actual Cost	Projected Cost	Projected Cost	Actual Cost
ES System								
ES Equipment	$40,500,750	$65,000,000	$1,359,000	$115,250,000	$679,500	$8,700,150	$40,500,750	$752,665
ES Installation	$2,025,038	$3,250,000	$67,950	$5,762,500	$33,975	$435,008	$2,025,038	$37,633
Enclosures	$2,139,360	$2,864,040	$36,214	$1,912,600	Included	$408,385	$2,139,360	Included
Owner Interconnection								
Equipment	$7,685,755	$7,685,755	Included	$18,893,500	$367,000	$2,288,500	$9,981,500	$233,500
Installation	$1,247,500	$1,247,500	Included	$2,361,500	$92,000	$572,000	$1,247,500	$58,500
Enclosures	Included	Included	Included	Included	Inlcuded	Included	Included	
System Packing	$0	$0	$0	$0	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$0	$0	$0	$0	$0	$0
Utility Interconnection								
Equipment	$3,875,000	$3,875,000	Included	$6,875,000	$80,400	$695,000	$3,875,000	$70,400
Installation	$3,875,000	$3,875,000	Included	$6,875,000	$80,400	$695,000	$3,875,000	$70,400
Site BOP Installation (Civil Only)	$1,041,180	$1,327,270	$13,507	$1,149,050	$6,754	$199,911	$1,041,180	$72,500
Total Cost Equipment	$54,200,865	$79,424,795	$1,395,214	$142,931,100	$1,126,900	$12,092,035	$56,496,610	$1,056,565
Total Cost Installation	$8,188,718	$9,699,770	$81,457	$16,148,050	$213,129	$1,901,919	$8,188,718	$239,033
General Contractor Facilities at 15% install	$1,228,308	$1,454,966	$0	$2,422,208	$31,969	$285,288	$1,228,308	$35,855
Engineering Fees @ 5% Install	$409,436	$484,989	$0	$807,403	$10,656	$95,096	$409,436	$11,952
Project Contingency Application @ 0-15% install	$1,228,308	$1,454,966	$0	$2,422,208	$31,969	$285,288	$1,228,308	$35,855
Process Contingency Application @ 0-15% of battery	$6,075,113	$9,750,000	$203,850	$17,287,500	$101,925	$1,305,023	$6,075,113	$112,900
Total Plant Cost (TPC)	**$71,330,746**	**$102,269,485**	**$1,680,522**	**$182,018,468**	**$1,516,549**	**$15,964,648**	**$73,626,491**	**$1,492,160**
OPERATING EXPENSES								
FIXED O&M - $/kW-yr	$3.6	$3.6	$0.0	$4.3	$9.2	$5.7	$4.5	$11.7
Replacement Battery Costs - $/kW	$194	$194	$204	$194	$194	$194	$194	$194
Battery replacement - yrs	8.0	8.0	5	8.0	8.0	8.0	8.0	8.0
Variable O&M - $/kWh (Charging or Discharging)	0.0005	0.0003	0.0001	0.0003	0.0014	0.0011	0.0005	0.0005

B.4.7 Zinc-bromine Systems

Data sheets for zinc- bromine system reference designs in several services and use cases are provided in Table B-18, Table B-19, and Table B-20.

Table B-18. Zinc-bromine System Cost and Performance Data for Bulk, Frequency Regulation, and Utility T&D Grid Support Services

(Parameters noted in black are vendor inputs.)

Application	**Bulk Storage**	**Bulk Storage**	**FR & RI**	**Utility T&D**	**Utility T&D**	**UTILITY T&D**	**UTILITY T&D**	**UTILITY T&D**
Technology Type	**Zinc Bromine**	**Zinc Bromine**	**Zinc Bromide**	**Zinc Bromine**	**Zinc Bromine**	**Zinc Bromide**	**Zinc Bromide**	**Zinc Bromide**
Supplier	**S29**	**S29**	**S29**	**S45**	**S45**	**S29 - 1**	**S29 - 1**	**S29 - 2**
Survey Year	2011	2011	2011	2011	2011	2011	2011	2011
DESIGN BASIS - General								
System Capacity - Net kW	50,000	100,000	1,000	1000	2000	1,000	10,000	10,000
Hours of Energy storage at rated Capacity - hrs	5.0	5.0	1.0	2	2	5.0	5.0	5.0
Depth of Discharge (DOD) per cycle - %	100%	100%	100%	100%	100%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	250,000	500,000	1,000	2000	4000	5,000	50,000	50,000
Energy Capacity - kWh @ 100% DOD	250,000	500,000	1,000	2000	4000	5,000	50,000	50,000
Auxiliaries - kW	80	80	20	0.04	0.04	20	80	20
Unit Size - Net kW	2,000	2,000	1000	0.25	0.5	500	2,000	500
Number of Units - #	25	50	1	4	4	2	5	20
Physical Size - SF/Unit	2,800	2,800	477	50'L x 48'W	20'W x 30'L	477	2,800	477
System Foot Print - SF	70,000	140,000	1,917	2500	800	3,195	14,000	9,540
System Weight - lbs	448,000	448,000	112,000	140,000 lbs	N/A	112,000	448,000	112,000
Round Trip AC / AC Efficiency - %	60%	60%	60%	62%	65%	60%	60%	60%
Number of cycles / year	365	365	5,000	365	365	500	500	500
GENERAL - Timing								
Commercial Order Date	--	--	--			--	--	--
Plant Life, yrs	15	15	15	15	15	15	15	15
TOTAL PLANT COST								
$/kW	$1,674	$1,641	$1,464	$2,957	$1,699	$2,053	$1,823	$1,805
$/kWh @ rated DOD	$335	$328	$1,464	$1,479	$849	$411	$365	$361
$/kWh @ 100% DOD	$335	$328	$1,464	$1,479	$849	$411	$365	$361
PLANT CAPITAL COST								
Power - $/kW	$484	$451	$754	$797	$619	$575	$633	$615
Storage - $/kWh @ rated DOD	$238	$238	$710	$1,080	$540	$296	$238	$238
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	$	$	Actual Cost	Actual Cost	Actual Cost
ES System								
ES Equipment	$50,000,000	$100,000,000	$600,000	$1,800,000	$1,800,000	$1,250,000	$10,000,000	$10,000,000
ES Installation	$2,000,000	$4,000,000	$20,000	$90,000	$90,000	$40,000	$400,000	$400,000
Enclosures	$2,520,000	$5,040,000	$71,012	$92,000	$30,800	$117,020	$506,000	$345,440
Owner Interconnection								
Equipment	$9,981,500	$18,893,500	$367,000	$367,000	$523,000	$240,000	$2,288,500	$2,288,500
Installation	$1,247,500	$2,361,500	$92,000	$92,000	$131,000	$10,000	$572,000	$572,000
Enclosures	Included	included	Included	included	included	Included	Included	Included
System Packing	Included	included	N/A	0	0	N/A	N/A	N/A
System Shipping to US Port	$0	$0	$0	0	0	$0	$0	$0
Utility Interconnection								
Equipment	$3,875,000	$6,875,000	$80,400	$80,400	$210,400	$80,400	$1,144,250	$1,144,250
Installation	$3,875,000	$6,875,000	$80,400	$80,400	$210,400	$80,400	$1,144,250	$1,144,250
Site BOP Installation (Civil Only)	$140,000	$280,000	$3,834	$5,000	$1,600	$6,390	$28,000	$19,080
Total Cost Equipment	$66,376,500	$130,808,500	$1,118,412	$2,339,400	$2,564,200	$1,687,420	$13,938,750	$13,778,190
Total Cost Installation	$7,262,500	$13,516,500	$196,234	$267,400	$433,000	$136,790	$2,144,250	$2,135,330
General Contractor Facilities at 15% install	$1,089,375	$2,027,475	$29,435	$40,110	$64,950	$20,519	$321,638	$320,300
Engineering Fees @ 5% Install	$363,125	$675,825	$9,812	$13,370	$21,650	$6,840	$107,213	$106,767
Project Contingency Application @ 0-15% install	$1,089,375	$2,027,475	$19,623	$26,740	$43,300	$13,679	$214,425	$213,533
Process Contingency Application @ 0-15% of battery	$7,500,000	$15,000,000	$90,000	$270,000	$270,000	$187,500	$1,500,000	$1,500,000
Total Plant Cost (TPC)	$83,680,875	$164,055,775	$1,463,516	$2,957,020	$3,397,100	$2,052,747	$18,226,275	$18,054,119
OPERATING EXPENSES								
FIXED O&M - $/kW-yr	$4.5	$4.3	$9.2	$9.2	$6.5	$5.0	$5.7	$5.7
Replacement Battery Costs - $/kW	$0	$0	$0	$540	$270	$0	$0	$0
Battery replacement - yrs	15	15	15	5	5	15	15	15
Variable O&M - $/kWh (Charging or Discharging)	0.0005	0.0005	0.0004	0.0027	0.0027	0.0008	0.0008	0.0008

Table B-19. Zinc-bromine System Cost and Performance Data for Distributed Energy Storage and Commercial and Industrial Energy Management Services

(Parameters noted in black are vendor inputs.)

Application	**Commerical & Industrial**	**Commercial & Industrial**	**Commerical & Industrial**	**Commercial & Industrial**	**Commerical & Industrial**	**Commerical & Industrial**	**Commerical & Industrial**
Technology Type	**Zinc Bromine**	**Zinc Bromine**	**Zinc Bromine**	**Zinc Bromine**	**Zinc Bromine**	**Zinc Bromide**	**Zinc Bromine**
Supplier	**S33**	**S33**	**S29**	**S29**	**S29**	**S29**	**S29**
Survey Year	2011	2011	2011	2011	2011	2011	2011
DESIGN BASIS - General							
System Capacity - Net kW	120	333	37.5	50	125	500	1,000
Hours of Energy storage at rated Capacity - hrs	2	2	4	2	5	5.0	5.0
Depth of Discharge (DOD) per cycle - %	100%	100%	100%	100%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	240	666	150	100	625	2,500	5,000
Energy Capacity - kWh @ 100% DOD	240	666	150	100	625	2,500	5,000
Auxiliaries - kW	no chiller req'd	no chiller req'd	4	2	5	20	20
Unit Size - Net kW	120	333	37.5	50	125	500	500
Number of Units - #	1	1	1	1	1	1	2
Physical Size - SF/Unit	160	160	95	97	160	477	477
System Foot Print - SF	160	160	275	255	988	1,917	3,195
System Weight - lbs	up to 33000	up to 33000	17,500	14,962	28000	112,000	112,000
Round Trip AC / AC Efficiency - %	63%	67%	60%	60%	60%	60%	60%
Number of cycles / year	365	365	365	365	365	365	365
GENERAL - Timing							
Commercial Order Date	Q4-2011	Q3-2012	--	--	--	--	--
Plant Life, yrs	15	15	15	15	15	15	15
TOTAL PLANT COST							
$/kW	$4,773	$4,499	$4,488	$3,021	$2,808	$2,584	$2,286
$/kWh @ rated DOD	$2,386	$2,250	$1,122	$1,510	$562	$517	$457
$/kWh @ 100% DOD	$2,386	$2,250	$1,122	$1,510	$562	$517	$457
PLANT CAPITAL COST							
Power - $/kW	$1,153	$982	$3,108	$2,331	$1,308	$1,107	$809
Storage - $/kWh @ rated DOD	$1,810	$1,759	$345	$345	$300	$296	$296
SYSTEM COSTS - Equipment & Install	Projected Cost	Projected Cost		Actual Cost	Actual Cost	Actual Cost	Actual Cost
ES System							
ES Equipment	$360,000	$999,000	$45,000	$30,000	$156,250	$625,000	$1,250,000
ES Installation	$18,000	$19,980	$2,250	$1,500	$7,813	$20,000	$40,000
Enclosures	Included	Included	$20,032	$20,032	$37,568	$71,012	$117,020
Owner Interconnection							
Equipment	$79,000	$131,500	$44,500	$44,500	$79,000	$233,500	$367,000
Installation	$39,500	$33,000	$22,500	$22,500	$39,500	$58,500	$92,000
Enclosures	Included	Included	Included	Included	Included	Included	Included
System Packing	$2,000	$2,000	Included	Included	Included	Included	Included
System Shipping to US Port	$2,400	$2,400	$0	$0	$0	$0	$0
Utility Interconnection							
Equipment	$250	$62,900	$250	$250	$250	$70,400	$80,400
Installation	$250	$62,900	$250	$250	$250	$70,400	$80,400
Site BOP Installation (Civil Only)	included	included	$29,000	$29,000	$1,976	$3,834	$6,390
Total Cost Equipment	$443,650	$1,197,800	$109,782	$94,782	$273,068	$999,912	$1,814,420
Total Cost Installation	$57,750	$115,880	$54,000	$53,250	$49,539	$152,734	$218,790
General Contractor Facilities at 15% install	$8,663	$17,382	$0	$0	$0	$22,910	$32,819
Engineering Fees @ 5% Install	$2,888	$5,794	$0	$0	$0	$7,637	$10,940
Project Contingency Application @ 0-15% install	$5,775	$11,588	$0	$0	$4,954	$15,273	$21,879
Process Contingency Application @ 0-15% of battery	$54,000	$149,850	$4,500	$3,000	$23,438	$93,750	$187,500
Total Plant Cost (TPC)	**$572,725**	**$1,498,294**	$168,282	$151,032	$350,998	$1,292,216	$2,286,347
OPERATING EXPENSES							
FIXED O&M - $/kW-yr	$19.8	$9.9	$35.7	$26.8	$19.0	$11.7	$9.2
Replacement Battery Costs - $/kW	$900	$900	$0	$0	$0	$0	$0
Battery replacement - yrs	5	5	15	15	15	15	15
Variable O&M - $/kWh (Charging or Discharging)	0.0027	0.0027	0.0014	0.0027	0.0011	0.0011	0.0011

Table B-20. Zinc-bromine Systems for Small Residential Applications

(Parameters noted in black are vendor inputs.)

Application	**Residential**	**Residential**	**Residential**	**Residential**	**Residential**
Technology Type	**Zinc-Bromine**	**Zinc-Bromine**	**Zinc-Bromine**	**Zinc Bromine**	**Zinc Bromine**
Supplier	**S33 - 1**	**S33 - 2**	**S33**	**S29**	**S29**
Survey Year	2011	2011	2011	2011	2011
DESIGN BASIS - General					
System Capacity - Net kW	5	5	5	5	15
Hours of Energy storage at rated Capacity - hrs	2	2	4	4	2
Depth of Discharge (DOD) per cycle - %	100%	100%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	10	10	20	20	30
Energy Capacity - kWh @ 100% DOD	10	10	20	20	30
Auxiliaries - kW	no chiller req'd	no chiller req'd	no chiller req'd	0.2	0.6
Unit Size - Net kW	5	5	5	5	15
Number of Units - #	1	1	1	1	1
Physical Size - SF/Unit	2.5	3	14	12	12
System Foot Print - SF	2.5	3	14	90	90
System Weight - lbs	484 (220 kg)	730 (330 kg)	2090 (950 kg)	N/A	5,325
Round Trip AC / AC Efficiency - %	70%	68%	63%	60%	60%
Number of cycles / year	365	365	365	365	365
GENERAL - Timing					
Commercial Order Date	Today	Today	Today	--	--
Plant Life, yrs	15	15	15	15	15
TOTAL PLANT COST					
$/kW	$7,040	$6,510	$10,020	$4,950	$3,380
$/kWh @ rated DOD	$3,520	$3,255	$2,505	$1,238	$1,690
$/kWh @ 100% DOD	$3,520	$3,255	$2,505	$1,238	$1,690
PLANT CAPITAL COST					
Power - $/kW	$3,570	$3,000	$3,000	$3,570	$2,690
Storage - $/kWh @ rated DOD	$1,735	$1,755	$1,755	$345	$345
SYSTEM COSTS - Equipment & Install	Projected Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost
ES System					
ES Equipment	$15,000	$15,000	$30,000	$6,000	$9,000
ES Installation	$750	$750	$1,500	$300	$450
Enclosures	$2,350	included	included	$2,350	$2,350
Owner Interconnection					
Equipment	$9,500	$9,500	$9,500	$9,500	$24,500
Installation	$5,000	$5,000	$5,000	$5,000	$12,500
Enclosures	included	included	included	Included	Included
System Packing	included	included	included	Included	Included
System Shipping to US Port	$100	$300	$600	$0	$0
Utility Interconnection					
Equipment	$250	$250	$250	$250	$250
Installation	$250	$250	$250	$250	$250
Site BOP Installation (Civil Only)	$500	included	included	$500	$500
Total Cost Equipment	$27,200	$25,050	$40,350	$18,100	$36,100
Total Cost Installation	$6,500	$6,000	$6,750	$6,050	$13,700
General Contractor Facilities at 15% install	$0	$0	$0	$0	$0
Engineering Fees @ 5% Install	$0	$0	$0	$0	$0
Project Contingency Application @ 0-15% install	$0	$0	$0	$0	$0
Process Contingency Application @ 0-15% of battery	$1,500	$1,500	$3,000	$600	$900
Total Plant Cost (TPC)	**$35,200**	**$32,550**	**$50,100**	$24,750	$50,700
OPERATING EXPENSES					
FIXED O&M - $/kW-yr	$58.0	$58.0	$58.0	$58.0	$49.3
Replacement Battery Costs - $/kW	$900	$900	$1,800	$0	$0
Battery replacement - yrs	5	5	5	15	15
Variable O&M - $/kWh (Charging or Discharging)	0.0027	0.0027	0.0014	0.0014	0.0027

B.4.8 Zinc-air Battery

Performance and Design Characteristics

Projected performance, capital costs, and design characteristics are illustrated in the Table B-21.

Note: These are features for systems that vendors may offer at some future time. As this technology is still in the very early stages of development, many of these features would require updating based on the RFI and RFP process detailed in this Handbook.

Table B-21. Cost and Performance Data for Zinc-air Batteries
(Parameters noted in black are vendor inputs.)

Application	Bulk Storage	Utility T&D	Commerical & Industrial
Technology Type	Zn / Air	Zn/ Air	Zn/ Air
Supplier	S20	S20	S20
Survey Year	2011	2011	2011
DESIGN BASIS - General			
System Capacity - Net kW	50,000	1,000	1,000
Hours of Energy storage at rated Capacity - hrs	6	6	6
Depth of Discharge (DOD) per cycle - %	100%	100%	100%
Energy Capacity - kWh @ rated DOD	300,000	6,000	6,000
Energy Capacity - kWh @ 100% DOD	300,000	6,000	6,000
Auxiliaries - kW			
Unit Size - Net kW	1 MW per unit	1 MW per unit	1 MW per unit
Number of Units - #	50	1	1
Physical Size - SF/Unit			
System Foot Print - SF	31,680	634	634
System Weight - lbs	80,000	80,000	80,000
Round Trip AC / AC Efficiency - %	80%	80%	80%
Number of cycles / year	365	365	365
GENERAL - Timing			
Commercial Order Date	Now	Now	Now
Plant Life, yrs	15	15	15
TOTAL PLANT COST			
$/kW	$1,428	$1,858	$1,858
$/kWh @ rated DOD	$238	$310	$310
$/kWh @ 100% DOD	$238	$310	$310
PLANT CAPITAL COST			
Power - $/kW	$443	$700	$700
Storage - $/kWh @ rated DOD	$164	$193	$193
SYSTEM COSTS - Equipment & Install	Projected Cost	Actual Cost	Actual Cost
ES System			
ES Equipment	$42,500,000	$1,000,000	$1,000,000
ES Installation	$375,000	$7,500	$7,500
Enclosures	$1,142,480	$24,810	$24,810
Owner Interconnection			
Equipment	$9,981,500	$367,000	$367,000
Installation	$1,247,500	$92,000	$92,000
Enclosures	Inlcuded	Inlcuded	Inlcuded
System Packing	$0	$0	$0
System Shipping to US Port	$0	$0	$0
Utility Interconnection			
Equipment	$3,875,000	$80,400	$80,400
Installation	$3,875,000	$80,400	$80,400
Site BOP Installation (Civil Only)	$63,360	$1,267	$1,267
Total Cost Equipment	$57,498,980	$1,472,210	$1,472,210
Total Cost Installation	$5,560,860	$181,167	$181,167
General Contractor Facilities at 15% install	$834,129	$27,175	$27,175
Engineering Fees @ 5% Install	$278,043	$9,058	$9,058
Project Contingency Application @ 0-15% install	$834,129	$18,117	$18,117
Process Contingency Application @ 0-15% of battery	$6,375,000	$150,000	$150,000
Total Plant Cost (TPC)	$71,381,141	$1,857,727	$1,857,727
OPERATING EXPENSES			
FIXED O&M - $/kW-yr	$4.5	$9.2	$9.2
Replacement Battery Costs - $/kW	$0	$0	$0
Battery replacement - yrs	15	15	15
Variable O&M - $/kWh (Charging or Discharging)	0.0005	0.0009	0.0009

B.4.9 Lead-acid Battery

Cost, performance, and technical design features of advanced lead acid energy storage systems are detailed in Table B-22 through Table B-26 by general service and use cases: Bulk Energy, Frequency Regulation/Renewable Integration, Utility T&D Grid Support, and smaller systems for Distributed Energy Storage, C&I Energy management, and Residential Energy management.

Table B-22. Cost and Performance of Advanced Lead-acid Batteries in Bulk Storage Service
(Parameters noted in black are vendor inputs.)

Application	Bulk Storage	Bulk Storage	Bulk Storage	Bulk Storage	Bulk Storage	Bulk Storage	Bulk Storage
Technology Type	Adv. Lead Acid	Adv. Lead Acid	Adv. Lead Acid	Adv. Lead Acid	Adv. Lead Acid	Adv. Lead Acid	Adv. Lead Acid
Supplier	S15	S15	S11	S11	S13	S44	S44
Survey Year	2010	2010	2011	2011	2011	2010	2010
DESIGN BASIS - General							
System Capacity - Net kW	20,000	50,000	50,000	100,000	50,000	50,000	100,000
Hours of Energy storage at rated Capacity - hrs	6	5	5	4	5	4.8	4.8
Depth of Discharge (DOD) per cycle - %	33%	33%	60%	60%	80%	75%	75%
Energy Capacity - kWh @ rated DOD	120,000	250,000	250,000	400,000	250,000	240,000	480,000
Energy Capacity - kWh @ 100% DOD	363,636	757,576	416,667	666,667	312,500	320,000	640,000
Auxiliaries - kW			n/a	n/a			
Unit Size - Net kW	20,000	50,000	n/a	n/a		100	100
Number of Units - #	685	1713	Building Concept	Building Concept	Chino x 5		
Physical Size - SF/Unit			Not used	Not used			
System Foot Print - SF	101169	252923	95,000	110,000	103200	120,000	240,000
System Weight - lbs			n/a	n/a	5 x 627,800 lbs		
Round Trip AC / AC Efficiency - %	90%	90%	90%	90%	85%	85%	85%
Number of cycles / year	365	365	365	365	365	365	365
GENERAL - Timing							
Commercial Order Date			2012	2012		6 to 9 Months	
Plant Life, yrs	15	15	15	15	15	15	15
TOTAL PLANT COST							
$/kW	$5,876	$4,897	$4,809	$4,326	$1,743	$2,287	$2,254
$/kWh @ rated DOD	$979	$979	$962	$1,082	$349	$476	$470
$/kWh @ 100% DOD	$323	$323	$577	$649	$279	$357	$352
PLANT CAPITAL COST							
Power - $/kW	$796	$663	$634	$546	$507	$527	$494
Storage - $/kWh @ rated DOD	$847	$847	$835	$945	$247	$367	$367
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost
ES System							
ES Equipment	$92,363,636	$192,424,242	$175,000,000	$320,000,000	$56,200,000	$80,000,000	$160,000,000
ES Installation	$4,618,182	$9,621,212	$25,000,000	$42,000,000	$2,810,000	$4,000,000	$8,000,000
Enclosures	$3,644,084	$9,107,228	$3,422,000	$3,962,000	$3,717,200	$4,322,000	$8,642,000
Owner Interconnection							
Equipment	$5,154,500	$9,981,500	$9,981,500	$18,893,500	$9,981,500	$9,981,500	$18,893,500
Installation	$644,500	$1,247,500	$1,247,500	$2,361,500	$1,247,500	$1,247,500	$2,361,500
Enclosures	included	included	Inlcuded	Included	Included	Included	included
System Packing	$0	$0	$0	$0	$0	included	included
System Shipping to US Port	$0	$0	$0	$0	$0	$0	$0
Utility Interconnection							
Equipment	$2,012,500	$3,875,000	$3,875,000	$6,875,000	$3,875,000	$3,875,000	$6,875,000
Installation	$2,012,500	$3,875,000	$3,875,000	$6,875,000	$3,875,000	$3,875,000	$6,875,000
Site BOP Installation (Civil Only)	$202,338	$505,846	$190,000	$220,000	$206,400	$240,000	$480,000
Total Cost Equipment	$103,174,720	$215,387,970	$192,278,500	$349,730,500	$73,773,700	$98,178,500	$194,410,500
Total Cost Installation	$7,477,520	$15,249,558	$30,312,500	$51,456,500	$8,138,900	$9,362,500	$17,716,500
General Contractor Facilities at 15% install	$1,121,628	$2,287,434	$4,546,875	$7,718,475	$1,220,835	$1,404,375	$2,657,475
Engineering Fees @ 5% Install	$373,876	$762,478	$1,515,625	$2,572,825	$406,945	$468,125	$885,825
Project Contingency Application @ 0-15% install	$747,752	$1,524,956	$3,031,250	$5,145,650	$813,890	$936,250	$1,771,650
Process Contingency Application @ 0-15% of battery	$4,618,182	$9,621,212	$8,750,000	$16,000,000	$2,810,000	$4,000,000	$8,000,000
Total Plant Cost (TPC)	$117,513,678	$244,833,608	$240,434,750	$432,623,950	$87,164,270	$114,349,750	$225,441,950
OPERATING EXPENSES							
FIXED O&M - $/kW-yr	$5.8	$4.5	$4.5	$4.3	$4.5	$4.5	$4.3
Replacement Battery Costs - $/kW	$1,385	$1,155	$1,050	$960	$337	$480	$480
Battery replacement - yrs	8	8	8	8	8	8	8
Variable O&M - $/kWh (Charging or Discharging)	0.0005	0.0005	0.0005	0.0007	0.0005	0.0006	0.0006

Table B-23. Cost and Performance of Advanced Lead-acid Batteries for Frequency Regulation

(Parameters noted in black are vendor inputs.)

Application	FR & RI	FR & RI	FR & RI	FR & RI	FR & RI
Technology Type	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**
Supplier	**S15**	**S15**	**S11**	**S11**	**S11**
Survey Year	2010	2010	2011	2011	2011
DESIGN BASIS - General					
System Capacity - Net kW	1,000	1,000	1,000	12,000	100,000
Hours of Energy storage at rated Capacity - hrs	0.25	1	0.5	0.4	0.4
Depth of Discharge (DOD) per cycle - %	33%	33%	85%	25%	25%
Energy Capacity - kWh @ rated DOD	250	1,000	500	4,800	40,000
Energy Capacity - kWh @ 100% DOD	758	3,030	588	19,200	160,000
Auxiliaries - kW			n/a	n/a	n/a
Unit Size - Net kW			n/a	n/a	n/a
Number of Units - #	1	11	Container	Container or	Building Concept
Physical Size - SF/Unit		60X71	160 sf each x 3 =	Not used	Not used
System Foot Print - SF	387	4260	3 x 20ft	3,500	30,000
System Weight - lbs			1 container at	If Containers, 4	n/a
Round Trip AC / AC Efficiency - %	90%	90%	90%	90%	90%
Number of cycles / year	5000	5000	5000	5000	15000
GENERAL - Timing					
Commercial Order Date			Q4/2010	Q4/2010	Q4/2010
Plant Life, yrs	15	15	15	15	15
TOTAL PLANT COST					
$/kW	$1,176	$2,477	$1,695	$1,692	$1,663
$/kWh @ rated DOD	$4,705	$2,477	$3,391	$4,230	$4,157
$/kWh @ 100% DOD	$1,553	$817	$2,882	$1,058	$1,039
PLANT CAPITAL COST					
Power - $/kW	$685	$847	$751	$442	$449
Storage - $/kWh @ rated DOD	$1,963	$1,629	$1,888	$3,125	$3,033
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost
ES System					
ES Equipment	$446,212	$1,481,040	$880,000	$12,000,000	$96,500,000
ES Installation	$22,311	$74,052	$20,000	$2,400,000	$20,000,000
Enclosures	$15,932	$155,360	$79,680	$128,000	$1,082,000
Owner Interconnection					
Equipment	$367,000	$367,000	$367,000	$2,288,500	$18,893,500
Installation	$92,000	$92,000	$92,000	$572,000	$2,361,500
Enclosures	included	included	included	included	Included
System Packing	$0	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$0	$0	$0
Utility Interconnection					
Equipment	$80,400	$80,400	$57,900	$695,000	$6,875,000
Installation	$80,400	$80,400	$57,900	$695,000	$6,875,000
Site BOP Installation (Civil Only)	$774	$8,520	$43,500	$7,000	$60,000
Total Cost Equipment	$909,544	$2,083,800	$1,384,580	$15,111,500	$123,350,500
Total Cost Installation	$195,485	$254,972	$213,400	$3,674,000	$29,296,500
General Contractor Facilities at 15% install	$29,323	$38,246	$32,010	$551,100	$4,394,475
Engineering Fees @ 5% Install	$9,774	$12,749	$10,670	$183,700	$1,464,825
Project Contingency Application @ 0-15% install	$9,774	$12,749	$10,670	$183,700	$2,929,650
Process Contingency Application @ 0-15% of battery	$22,311	$74,052	$44,000	$600,000	$4,825,000
Total Plant Cost (TPC)	$1,176,210	$2,476,567	$1,695,330	$20,304,000	$166,260,950
OPERATING EXPENSES					
FIXED O&M - $/kW-yr	$9.2	$9.2	$9.2	$4.8	$4.3
Replacement Battery Costs - $/kW	$134	$444	$264	$300	$290
Battery replacement - yrs	8	8	8	8	8
Variable O&M - $/kWh (Charging or Discharging)	0.0016	0.0004	0.0008	0.0005	0.0002

Table B-24. Cost and Performance of Advanced Lead-acid Batteries in Utility T&D

(Parameters noted in black are vendor inputs.)

Application	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**
Technology Type	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**	**Adv. Lead Acid**
Supplier	**S15**	**S15**	**S15**	**S15**	**S15**	**S44**	**S11**	**S11**	**S11**
Survey Year	2010	2010	2010	2010	2010	2010	2011	2011	2011
DESIGN BASIS - General									
System Capacity - Net kW	1,000	1,000	1000	1000	20,000	1,000	1,000	12,000	100,000
Hours of Energy storage at rated Capacity - hrs	1	4	8	10	6	3.2	4	4	4
Depth of Discharge (DOD) per cycle - %	33%	33%	50%	80%	33%	75%	60%	60%	60%
Energy Capacity - kWh @ rated DOD	1,000	4,000	8,000	10,000	120,000	3,200	4,000	48,000	400,000
Energy Capacity - kWh @ 100% DOD	3,030	12,121	16,000	12,500	363,636	4,267	6,667	80,000	666,667
Auxiliaries - kW							n/a	n/a	n/a
Unit Size - Net kW		1,000			20,000	1	n/a	n/a	n/a
Number of Units - #	11	26	29	29	685	3	Container	Building Concept	Building Concept
Physical Size - SF/Unit	60X71	60X128	60X141	60X141		1600	160 sf each x 15	Not used	Not used
System Foot Print - SF	4260	7680	8460	8460	101169	1,600	15 x 20ft	13,000	110,000
System Weight - lbs		2220				60000	1 container at	n/a	n/a
Round Trip AC / AC Efficiency - %	90%	90%	90%	90%	90%	87%	90%	90%	90%
Number of cycles / year	365	365	365	365	365	365	365	365	365
GENERAL - Timing									
Commercial Order Date						6 to 9 Months	Q4/2010	Q4/2010	Q4/2010
Plant Life, yrs	15	15	15	15	15	15	15	15	15
TOTAL PLANT COST									
$/kW	$2,477	$4,855	$5,334	$5,023	$5,876	$2,730	$5,166	$4,360	$3,990
$/kWh @ rated DOD	$2,477	$1,214	$667	$502	$979	$853	$1,291	$1,090	$998
$/kWh @ 100% DOD	$817	$401	$333	$402	$323	$640	$775	$654	$599
PLANT CAPITAL COST									
Power - $/kW	$847	$1,004	$1,039	$1,036	$796	$749	$1,344	$527	$546
Storage - $/kWh @ rated DOD	$1,629	$963	$537	$399	$847	$619	$956	$958	$861
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost
ES System									
ES Equipment	$1,481,040	$3,500,640	$3,904,560	$3,625,000	$92,363,636	$1,792,000	$3,600,000	$39,000,000	$288,000,000
ES Installation	$74,052	$175,032	$195,228	$181,250	$4,618,182	$89,600	$42,000	$5,040,000	$42,000,000
Enclosures	$155,360	$278,480	$306,560	$306,560	$3,644,084	$59,600	$398,400	$470,000	$3,962,000
Owner Interconnection									
Equipment	$367,000	$367,000	$367,000	$367,000	$5,154,500	$367,000	$367,000	$2,288,500	$18,893,500
Installation	$92,000	$92,000	$92,000	$92,000	$644,500	$92,000	$92,000	$572,000	$2,361,500
Enclosures	included	included	included	included	included	Included	included	included	Included
System Packing	$0	$0	$0	$0	$0	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$0	$0	$0	$10,000	$0	$0	$0
Utility Interconnection									
Equipment	$80,400	$80,400	$80,400	$80,400	$2,012,500	$80,400	$80,400	$695,000	$6,875,000
Installation	$80,400	$80,400	$80,400	$80,400	$2,012,500	$80,400	$80,400	$695,000	$6,875,000
Site BOP Installation (Civil Only)	$8,520	$15,360	$16,920	$16,920	$202,338	$3,200	$217,500	$26,000	$220,000
Total Cost Equipment	$2,083,800	$4,226,520	$4,658,520	$4,378,960	$103,174,720	$2,309,000	$4,445,800	$42,453,500	$317,730,500
Total Cost Installation	$254,972	$362,792	$384,548	$370,570	$7,477,520	$265,200	$431,900	$6,333,000	$51,456,500
General Contractor Facilities at 15% install	$38,246	$54,419	$57,682	$55,586	$1,121,628	$39,780	$64,785	$949,950	$7,718,475
Engineering Fees @ 5% Install	$12,749	$18,140	$19,227	$18,529	$373,876	$13,260	$21,595	$316,650	$2,572,825
Project Contingency Application @ 0-15% install	$12,749	$18,140	$19,227	$18,529	$747,752	$13,260	$21,595	$316,650	$5,145,650
Process Contingency Application @ 0-15% of battery	$74,052	$175,032	$195,228	$181,250	$4,618,182	$89,600	$180,000	$1,950,000	$14,400,000
Total Plant Cost (TPC)	$2,476,567	$4,855,042	$5,334,433	$5,023,423	$117,513,678	$2,730,100	$5,165,675	$52,319,750	$399,023,950
OPERATING EXPENSES									
FIXED O&M - $/kW-yr	$9.2	$9.2	$9.2	$9.2	$5.8	$9.2	$9.2	$4.8	$4.3
Replacement Battery Costs - $/kW	$444	$1,050	$1,171	$1,088	$1,385	$538	$1,080	$975	$864
Battery replacement - yrs	8	8	8	8	8	8	8	8	8
Variable O&M - $/kWh (Charging or Discharging)	0.0055	0.0014	0.0007	0.0005	0.0005	0.0017	0.0014	0.0007	0.0007

Table B-25. Cost and Performance Data of Advanced Lead-acid Batteries

(Parameters noted in black are vendor inputs.)

Application	**DESS**	**DESS**	**DESS**	**DESS**	**DESS**	**DESS**
Technology Type	**Advanced Lead Acid**	**Advanced Lead Acid**	**Advanced Lead Acid**	**Advanced VRLA**	**Advanced VRLA**	**VRLA**
Supplier	**S15**	**S15**	**S15**	**S21 - 1**	**S21 - 2**	**S21 - 3**
Survey Year	2010	2010	2010	2011	2011	2011
DESIGN BASIS - General						
System Capacity - Net kW	50	50	50	25	25	25
Hours of Energy storage at rated Capacity - hrs	2	4	5	2	2	2
Depth of Discharge (DOD) per cycle - %	80%	50%	80%	70%	70%	70%
Energy Capacity - kWh @ rated DOD	100	200	250	50	50	50
Energy Capacity - kWh @ 100% DOD	125	400	313	65	71	65
Auxiliaries - kW						
Unit Size - Net kW						
Number of Units - #				234 Units of	48 Units of battery	34 Units of battery
Physical Size - SF/Unit				84(H) x 25(W) x	56(H) x 46(W) x	84(H) x 25(W) x
System Foot Print - SF	20' container	20' container	20' container	2.45	7.6	3.65
System Weight - lbs				1,470lbs/stand	4,100 lbs/stand	2,147 lbs/ stand
Round Trip AC / AC Efficiency - %	90%	90%	90%	85%	85%	85%
Number of cycles / year	365	365	365	365	365	365
GENERAL - Timing						
Commercial Order Date						
Plant Life, yrs	15	15	15	15	15	15
TOTAL PLANT COST						
$/kW	$2,499	$4,505	$2,782	$5,526	$3,789	$2,609
$/kWh @ rated DOD	$1,249	$1,126	$556	$2,763	$1,894	$1,304
$/kWh @ 100% DOD	$1,000	$563	$445	$2,125	$1,326	$1,003
PLANT CAPITAL COST						
Power - $/kW	$1,407	$1,407	$1,407	$1,994	$1,994	$1,994
Storage - $/kWh @ rated DOD	$546	$774	$275	$1,766	$897	$307
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost
ES System						
ES Equipment	$49,625	$140,800	$62,500	$80,275	$40,786	$13,975
ES Installation	$2,481	$7,040	$3,125	$4,014	$2,039	$699
Enclosures	$2,350	$2,350	$2,350	$2,350	$2,350	$2,350
Owner Interconnection						
Equipment	$44,500	$44,500	$44,500	$31,000	$31,000	$31,000
Installation	$22,500	$22,500	$22,500	$15,500	$15,500	$15,500
Enclosures	included	included	included	Included	Included	Included
System Packing	$0	$0	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$0	$0	$0	$0
Utility Interconnection						
Equipment	$250	$250	$250	$250	$250	$250
Installation	$250	$250	$250	$250	$250	$250
Site BOP Installation (Civil Only)	$500	$500	$500	$500	$500	$500
Total Cost Equipment	$96,725	$187,900	$109,600	$113,875	$74,386	$47,575
Total Cost Installation	$25,731	$30,290	$26,375	$20,264	$18,289	$16,949
General Contractor Facilities at 15% install	$0	$0	$0	$0	$0	$0
Engineering Fees @ 5% Install	$0	$0	$0	$0	$0	$0
Project Contingency Application @ 0-15% install	$0	$0	$0	$0	$0	$0
Process Contingency Application @ 0-15% of battery	$2,481	$7,040	$3,125	$4,014	$2,039	$699
Total Plant Cost (TPC)	$124,938	$225,230	$139,100	**$138,153**	**$94,714**	**$65,223**
OPERATING EXPENSES						
FIXED O&M - $/kW-yr	$26.8	$26.8	$26.8	$37.2	$37.2	$37.2
Replacement Battery Costs - $/kW	$298	$845	$375	$2,902	$1,468	$480
Battery replacement - yrs	8	8	8	8	8	3
Variable O&M - $/kWh (Charging or Discharging)	0.0027	0.0014	0.0011	0.0027	0.0027	0.0027

Table B-26. Cost and Performance of Advanced Lead-acid Batteries for Commercial and Industrial Applications

(Parameters noted in black are vendor inputs.)

Application	**Commercial & Industrial**	**Commercial & Industrial**	**Commercial & Industrial**	**Commercial & Industrial**	**Commercial & Industrial**	**Commerical & Industrial**	**Residential**	**Residential**
Technology Type	**Advanced Lead Acid**	**Advanced Lead Acid**	**Advanced Lead Acid**	**Advanced Lead Acid**	**Advanced Lead Acid**	**Adv. Lead Acid**	**Advanced Lead Acid**	**Advanced Lead Acid**
Supplier	**S15**	**S15**	**S15**	**S15**	**S15**	**S11**	**S15**	**S15**
Survey Year	2010	2010	2010	2010	2010	2011	2010	2010
DESIGN BASIS - General								
System Capacity - Net kW	50	50	50	1000	1000	200	5	5
Hours of Energy storage at rated Capacity - hrs	2	4	5	8	10	4	2	4
Depth of Discharge (DOD) per cycle - %	80%	50%	80%	33%	80%	60%	33%	50%
Energy Capacity - kWh @ rated DOD	100	200	250	8,000	10,000	800	10	20
Energy Capacity - kWh @ 100% DOD	125	400	313	24,242	12,500	1,333	30	40
Auxiliaries - kW								
Unit Size - Net kW						200		
Number of Units - #				44	29		1	1
Physical Size - SF/Unit				110X197	60X141			
System Foot Print - SF	pad mtd cabinet	20' container	20' container	21670	8460	154		
System Weight - lbs						152,000		
Round Trip AC / AC Efficiency - %	90%	90%	90%	90%	90%	75%	90%	90%
Number of cycles / year	365	365	365	365	365	365	365	365
GENERAL - Timing								
Commercial Order Date						Q4/2010		
Plant Life, yrs	15	15	15	15	15	15	15	15
TOTAL PLANT COST								
$/kW	$2,499	$4,505	$2,782	$8,090	$5,023	$5,995	$6,323	$6,509
$/kWh @ rated DOD	$1,249	$1,126	$556	$1,011	$502	$1,499	$3,162	$1,627
$/kWh @ 100% DOD	$1,000	$563	$445	$334	$402	$899	$1,043	$814
PLANT CAPITAL COST								
Power - $/kW	$1,407	$1,407	$1,407	$1,573	$1,036	$1,795	$3,570	$3,570
Storage - $/kWh @ rated DOD	$546	$774	$275	$815	$399	$1,050	$1,377	$735
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost
ES System								
ES Equipment	$49,625	$140,800	$62,500	$5,924,160	$3,625,000	$800,000	$12,515	$13,360
ES Installation	$2,481	$7,040	$3,125	$296,208	$181,250	included	$626	$668
Enclosures	$2,350	$2,350	$2,350	$782,120	$306,560	$26,560	$2,350	$2,350
Owner Interconnection								
Equipment	$44,500	$44,500	$44,500	$367,000	$367,000	$131,500	$9,500	$9,500
Installation	$22,500	$22,500	$22,500	$92,000	$92,000	$33,000	$5,000	$5,000
Enclosures	included	included	included	included	included	included	Included	Included
System Packing	$0	$0	$0	$0	$0	included	Included	Included
System Shipping to US Port	$0	$0	$0	$0	$0	included	$0	$0
Utility Interconnection								
Equipment	$250	$250	$250	$80,400	$80,400	$62,900	$250	$250
Installation	$250	$250	$250	$80,400	$80,400	$62,900	$250	$250
Site BOP Installation (Civil Only)	$500	$500	$500	$43,340	$16,920	$14,500	$500	$500
Total Cost Equipment	$96,725	$187,900	$109,600	$7,153,680	$4,378,960	$1,020,960	$24,615	$25,460
Total Cost Installation	$25,731	$30,290	$26,375	$511,948	$370,570	$110,400	$6,376	$6,418
General Contractor Facilities at 15% install	$0	$0	$0	$76,792	$55,586	$16,560	$0	$0
Engineering Fees @ 5% Install	$0	$0	$0	$25,597	$18,529	$5,520	$0	$0
Project Contingency Application @ 0-15% install	$0	$0	$0	$25,597	$18,529	$5,520	$0	$0
Process Contingency Application @ 0-15% of battery	$2,481	$7,040	$3,125	$296,208	$181,250	$40,000	$626	$668
Total Plant Cost (TPC)	$124,938	$225,230	$139,100	$8,089,823	$5,023,423	$1,198,960	$31,617	$32,546
OPERATING EXPENSES								
FIXED O&M - $/kW-yr	$26.8	$26.8	$26.8	$9.2	$9.2	$16.5	$58.0	$58.0
Replacement Battery Costs - $/kW	$298	$845	$375	$1,777	$1,088	$1,200	$751	$802
Battery replacement - yrs	8	8	8	8	8	8	8	8
Variable O&M - $/kWh (Charging or Discharging)	0.0027	0.0014	0.0011	0.0007	0.0005	0.0014	0.0027	0.0014

B.4.10 Flywheel

Table B-27 provides performance and design characteristics for a 20-MW flywheel system designed for providing grid frequency regulation services.

Table B-27. Cost and Performance of Flywheel Systems
(Parameters noted in black are vendor inputs.)

Application	**FR & RI**
Technology Type	**Flywheel**
Supplier	**S5**
Survey Year	2010
DESIGN BASIS - General	
System Capacity - Net kW	20000
Hours of Energy storage at rated Capacity - hrs	0.25
Depth of Discharge (DOD) per cycle - %	100%
Energy Capacity - kWh @ rated DOD	5,000
Energy Capacity - kWh @ 100% DOD	5,000
Auxiliaries - kW	capacity net of auxiliaries
Unit Size - Net kW	1
Number of Units - #	20
Physical Size - SF/Unit	20X 1 MW (= 200 flywheels)
System Foot Print - SF	20X 1 MW (= 200 flywheels)
System Weight - lbs	
Round Trip AC / AC Efficiency - %	85%
Number of cycles / year	15,000
GENERAL - Timing	
Commercial Order Date	Now
Plant Life, yrs	15
TOTAL PLANT COST	
$/kW	$2,159
$/kWh @ rated DOD	$8,638
$/kWh @ 100% DOD	$8,638
PLANT CAPITAL COST	
Power - $/kW	$867
Storage - $/kWh @ rated DOD	$5,168
SYSTEM COSTS - Equipment & Install	Actual Cost
ES System	
ES Equipment	$19,360,000
ES Installation	$6,480,000
Enclosures	included
Owner Interconnection	
Equipment	$5,154,500
Installation	$644,500
Enclosures	included
System Packing	$0
System Shipping to US Port	$0
Utility Interconnection	
Equipment	$2,012,500
Installation	$2,012,500
Site BOP Installation (Civil Only)	$3,680,000
Total Cost Equipment	$26,527,000
Total Cost Installation	$12,817,000
General Contractor Facilities at 15% install	$1,922,550
Engineering Fees @ 5% Install	$640,850
Project Contingency Application @ 0-15% install	$1,281,700
Process Contingency Application @ 0-15% of battery	$0
Total Plant Cost (TPC)	$43,189,100
OPERATING EXPENSES	
FIXED O&M - $/kW-yr	$5.8
Replacement Battery Costs - $/kW	$290
Battery replacement - yrs	5
Variable O&M - $/kWh (Charging or Discharging)	0.0003

B.4.11 Lithium Ion Family of Batteries

Performance, design, and cost data sheets for several Li-ion systems are presented in the tables below, by noted service or use case area. Table B-28 is for Lithium Ion (Li-ion) systems for frequency regulation and renewable integration applications from various suppliers noted by S.

Table B-28. Cost and Performance of Li-on Family of Battery Systems for Frequency Regulation and Renewables

(Parameters noted in black are vendor inputs.)

Application	**FR & RI**	**FR & RI**	**FR & RI**	**FR & RI**	**FR & RI**	**FR & RI**	**FR & RI**	**Wind Integration**
Technology Type	**Li-ion**	**Li-ion**	**Large format Li-ion**	**Large format Li-ion**	**Large format Li-ion**	**Li-ion**	**Li-ion**	**Li-ion**
Supplier	**S25**	**S19 - 1**	**S22**	**S22**	**S37**	**S1**	**S1**	**S7**
Survey Year	2010	2010	2010	2010	2010	2011	2011	2011
DESIGN BASIS - General								
System Capacity - Net kW	2,000	1000	1,000	1,000	1,100	3,000	2000	1000
Hours of Energy storage at rated Capacity - hrs	0.25	0.25	1.2	1.35	0.5	1	0.25	1
Depth of Discharge (DOD) per cycle - %	60%	80%	85%	85%	80%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	500	250	1,200	1,350	550	3,000	500	1000
Energy Capacity - kWh @ 100% DOD	833	313	1,412	1,588	688	3,000	500	1000
Auxiliaries - kW					6	12	25	
Unit Size - Net kW		1000				3,000	2000	200
Number of Units - #	1- 53' trailer/	1			1 or more	1	1	5
Physical Size - SF/Unit		1	20' x 9'6"x7"8"	20' x 9'6"x7"8"	160	53' X 9' X 9'	53' X 9' X 9'	
System Foot Print - SF		8X20 ft container			N/A	477	477	1,386
System Weight - lbs		50000	8775	8775	24000	160,000	60,000	
Round Trip AC / AC Efficiency - %	90%	80%	90%	90%	92%	90%	89%	90%
Number of cycles / year	5000	5000	365	365	365	4000	15000	365
GENERAL - Timing								
Commercial Order Date					Oct-10			2011. Jan
Plant Life, yrs	15	15	15	15	15	15	15	15
TOTAL PLANT COST								
$/kW	$1,010	$1,017	$2,551	$2,144	$1,475	$1,388	$1,098	$1,634
$/kWh @ rated DOD	$4,040	$4,068	$2,126	$1,588	$2,949	$1,388	$4,394	$1,634
$/kWh @ 100% DOD	$2,424	$3,254	$1,807	$1,350	$2,359	$1,388	$4,394	$1,634
PLANT CAPITAL COST								
Power - $/kW	$603	$779	$711	$707	$637	$514	$589	$728
Storage - $/kWh @ rated DOD	$1,629	$950	$1,533	$1,065	$1,674	$874	$2,037	$906
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Actual Cost	Projected Cost
ES System								
ES Equipment	$708,333	$175,000	$1,600,000	$1,250,000	$800,800	2,383,000	926,000	$780,000
ES Installation	$35,417	Included	$80,000	$62,500	$40,040	included	included	$39,000
Enclosures	Included	Included	$10,016	$10,016	$10,016	included	included	$51,910
Owner Interconnection								
Equipment	$523,000	$367,000	$367,000	$367,000	$367,000	$749,500	$523,000	$367,000
Installation	$131,000	$92,000	$92,000	$92,000	$92,000	$187,500	$131,000	$92,000
Enclosures	Included	included	included	included	Included	included	included	included
System Packing	$0	$28,125	$0	$0	$0	$0	$0	$0
System Shipping to US Port	$0	$45,000	$0	$0	$0	$0	$0	$8,644
Utility Interconnection								
Equipment	$210,400	$80,400	$80,400	$80,400	$80,400	$240,400	$210,400	$80,400
Installation	$210,400	$80,400	$80,400	$80,400	$80,400	$240,400	$210,400	$80,400
Site BOP Installation (Civil Only)	$29,000	$70,750	$14,500	$14,500	$14,500	$14,500	$14,500	$2,773
Total Cost Equipment	$1,441,733	$695,525	$2,057,416	$1,707,416	$1,258,216	$3,372,900	$1,659,400	$1,287,954
Total Cost Installation	$405,817	$243,150	$266,900	$249,400	$226,940	$442,400	$355,900	$214,173
General Contractor Facilities at 15% install	$60,873	$36,473	$40,035	$37,410	$34,041	$66,360	$53,385	$32,126
Engineering Fees @ 5% Install	$20,291	$12,158	$13,345	$12,470	$11,347	$22,120	$17,795	$10,709
Project Contingency Application @ 0-15% install	$20,291	$12,158	$13,345	$12,470	$11,347	$22,120	$17,795	$10,709
Process Contingency Application @ 0-15% of battery	$70,833	$17,500	$160,000	$125,000	$80,080	$238,300	$92,600	$78,000
Total Plant Cost (TPC)	$2,019,838	$1,016,963	$2,551,041	$2,144,166	$1,621,971	**$4,164,200**	**$2,196,875**	**$1,633,670**
OPERATING EXPENSES								
FIXED O&M - $/kW-yr	$6.5	$9.2	$9.2	$9.2	$8.3	$6.2	$6.5	$9.2
Replacement Battery Costs - $/kW	$177	$88	$800	$625	$364	$0	$0	$390
Battery replacement - yrs	5	5	5	5	5	15	15	5
Variable O&M - $/kWh (Charging or Discharging)	0.0016	0.0016	0.0046	0.0041	0.0110	0.0005	0.0005	0.0055

Table B-29. Li-ion Battery Systems for Utility T&D Grid Support

(Parameters noted in black are vendor inputs.)

Application	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**	**Utility T&D**
Technology Type	**Adv. Li-ion**	**Adv. Li-ion**	**Li-ion**	**Large format Li-ion**	**Large format Li-ion**	**Li-ion**	**Li-ion**	**Li-ion**
Supplier	**S6**	**S6**	**S25**	**S22**	**S22**	**S1**	**S7**	**S7**
Survey Year	2010	2010	2010	2010	2010	2011	2011	2011
DESIGN BASIS - General								
System Capacity - Net kW	1,000	10,000	10,000	1,000	1,000	3,000	1000	3000
Hours of Energy storage at rated Capacity - hrs	5	2	3	1.2	1.35	1	4	4
Depth of Discharge (DOD) per cycle - %	85%	85%	80%	85%	85%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	5,000	20,000	30,000	1,200	1,350	3,000	4000	12000
Energy Capacity - kWh @ 100% DOD	5,882	23,529	37,500	1,412	1,588	3,000	4000	12000
Auxiliaries - kW						12		
Unit Size - Net kW	1,000	10,000				3,000	100	500
Number of Units - #	125	500	Battery 5X53'			1	10	6
Physical Size - SF/Unit	500	288000		20' x 9'6"x7"8"	20' x 9'6"x7"8"	53' X 9' X 9'		
System Foot Print - SF	1100	4400				477	2,773	10,398
System Weight - lbs	654.368	654.368		8775	8775	160,000		
Round Trip AC / AC Efficiency - %	90%	90%	94%	90%	90%	90%	90%	90%
Number of cycles / year	365	365	365	365	365	365	365	365
GENERAL - Timing								
Commercial Order Date							Demo In BYD	2010.12
Plant Life, yrs	15	15	15	15	15	15	15	15
TOTAL PLANT COST								
$/kW	$4,981	$2,183	$5,265	$2,551	$2,144	$1,388	$4,420	$4,291
$/kWh @ rated DOD	$996	$1,092	$1,755	$2,126	$1,588	$1,388	$1,105	$1,073
$/kWh @ 100% DOD	$847	$928	$1,404	$1,807	$1,350	$1,388	$1,105	$1,073
PLANT CAPITAL COST								
Power - $/kW	$753	$492	$521	$711	$707	$514	$811	$681
Storage - $/kWh @ rated DOD	$846	$846	$1,581	$1,533	$1,065	$874	$902	$902
SYSTEM COSTS - Equipment & Install	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost	Projected Cost
ES System								
ES Equipment	$3,676,471	$14,705,882	$41,250,000	$1,600,000	$1,250,000	2,383,000	$3,120,000	$9,360,000
ES Installation	$183,824	$735,294	$2,062,500	$80,000	$62,500	included	$156,000	$468,000
Enclosures	$41,600	$160,400	Included	$10,016	$10,016	included	$101,820	$376,326
Owner Interconnection								
Equipment	$367,000	$2,288,500	$2,288,500	$367,000	$367,000	$749,500	$367,000	$749,500
Installation	$92,000	$572,000	$572,000	$92,000	$92,000	$187,500	$92,000	$187,500
Enclosures	Included	Included	Included	included	included	included	included	included
System Packing		$0	$0	$0	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$0	$0	$0	$0	$21,610	$64,830
Utility Interconnection								
Equipment	$80,400	$695,000	$695,000	$80,400	$80,400	$240,400	$80,400	$240,400
Installation	$80,400	$695,000	$695,000	$80,400	$80,400	$240,400	$80,400	$240,400
Site BOP Installation (Civil Only)	$2,200	$8,800	$100,000	$14,500	$14,500	$14,500	$5,546	$20,796
Total Cost Equipment	$4,165,471	$17,849,782	$44,233,500	$2,057,416	$1,707,416	$3,372,900	$3,690,830	$10,791,056
Total Cost Installation	$358,424	$2,011,094	$3,429,500	$266,900	$249,400	$442,400	$333,946	$916,696
General Contractor Facilities at 15% install	$53,764	$301,664	$514,425	$40,035	$37,410	$66,360	$50,092	$137,504
Engineering Fees @ 5% Install	$17,921	$100,555	$171,475	$13,345	$12,470	$22,120	$16,697	$45,835
Project Contingency Application @ 0-15% install	$17,921	$100,555	$171,475	$13,345	$12,470	$22,120	$16,697	$45,835
Process Contingency Application @ 0-15% of battery	$367,647	$1,470,588	$4,125,000	$160,000	$125,000	$238,300	$312,000	$936,000
Total Plant Cost (TPC)	$4,981,147	$21,834,238	$52,645,375	$2,551,041	$2,144,166	**$4,164,200**	**$4,420,262**	**$12,872,926**
OPERATING EXPENSES								
FIXED O&M - $/kW-yr	$9.2	$5.7	$5.7	$9.2	$9.2	$6.2	$9.2	$6.2
Replacement Battery Costs - $/kW	$1,838	$735	$2,063	$800	$625	$0	$1,560	$1,560
Battery replacement - yrs	5	5	5	5	5	15	5	5
Variable O&M - $/kWh (Charging or Discharging)	0.0011	0.0027	0.0018	0.0046	0.0041	0.0055	0.0014	0.0014

Table B-30. Li-ion Battery Systems for Distributed Energy Storage

(Parameters noted in black are vendor inputs.)

Application	**DESS**	**DESS**	**DESS**	**DESS**	**DESS**	**DESS**	**DESS**	**DESS**
Technology Type	**Adv. Li-ion**	**Adv. Li-ion**	**Li-ion**	**Li-ion**	**Large format Li-ion**	**Large format Li-ion**	**Large format Li-ion**	**Large format Li-ion**
Supplier	**S6**	**S6**	**S25**	**S19 - 1**	**S22**	**S22**	**S22**	**S22**
Survey Year	2010	2010	2010	2010	2010	2010	2010	2010
DESIGN BASIS - General								
System Capacity - Net kW	25	50	50	50	25	25	25	25
Hours of Energy storage at rated Capacity - hrs	2	4	2	3	1.1	3	1.2	3.2
Depth of Discharge (DOD) per cycle - %	85%	85%	80%	80%	85%	85%	85%	85%
Energy Capacity - kWh @ rated DOD	50	200	100	150	28	75	30	80
Energy Capacity - kWh @ 100% DOD	59	235	125	188	32	88	35	94
Auxiliaries - kW								
Unit Size - Net kW	25	50		50				
Number of Units - #	1	6	Pad mounted	1				
Physical Size - SF/Unit	15	24		1	43" x 25" x 23"	27" x 61" x "26	43" x 25" x 23"	27" x 61" x "26
System Foot Print - SF	15	26.4		4X4				
System Weight - lbs	880.88	654.368		5,000				
Round Trip AC / AC Efficiency - %	89%	89%	93%	80%	85%	85%	90%	90%
Number of cycles / year	365	365	365	365	365	365	365	365
GENERAL - Timing								
Commercial Order Date								
Plant Life, yrs	15	15	15	15	15	15	15	15
TOTAL PLANT COST								
$/kW	$3,685	$4,789	$4,570	$3,523	$4,064	$6,594	$4,064	$5,904
$/kWh @ rated DOD	$1,843	$1,197	$2,285	$1,174	$3,695	$2,198	$3,387	$1,845
$/kWh @ 100% DOD	$1,566	$1,018	$1,828	$939	$3,140	$1,868	$2,879	$1,568
PLANT CAPITAL COST								
Power - $/kW	$1,994	$1,407	$1,407	$1,896	$1,994	$1,994	$1,994	$1,994
Storage - $/kWh @ rated DOD	$846	$846	$1,581	$542	$1,882	$1,533	$1,725	$1,222
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost	Actual Cost
ES System								
ES Equipment	$36,765	$147,059	$137,500	$57,750	$45,000	$100,000	$45,000	$85,000
ES Installation	$1,838	$7,353	$6,875	Included	$2,250	$5,000	$2,250	$4,250
Enclosures	$2,350	$2,350	$2,350	Included	$2,350	$2,350	$2,350	$2,350
Owner Interconnection								
Equipment	$31,000	$44,500	$44,500	$44,500	$31,000	$31,000	$31,000	$31,000
Installation	$15,500	$22,500	$22,500	$22,500	$15,500	$15,500	$15,500	$15,500
Enclosures	Included	Included	Included	included	included	included	included	included
System Packing	$0	$0	$0	$9,000	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$0	$17,813	$0	$0	$0	$0
Utility Interconnection								
Equipment	$250	$250	$250	$250	$250	$250	$250	$250
Installation	$250	$250	$250	$250	$250	$250	$250	$250
Site BOP Installation (Civil Only)	$500	$500	$500	$18,313	$500	$500	$500	$500
Total Cost Equipment	$70,365	$194,159	$184,600	$129,313	$78,600	$133,600	$78,600	$118,600
Total Cost Installation	$18,088	$30,603	$30,125	$41,063	$18,500	$21,250	$18,500	$20,500
General Contractor Facilities at 15% install	$0	$0	$0	$0	$0	$0	$0	$0
Engineering Fees @ 5% Install	$0	$0	$0	$0	$0	$0	$0	$0
Project Contingency Application @ 0-15% install	$0	$0	$0	$0	$0	$0	$0	$0
Process Contingency Application @ 0-15% of battery	$3,676	$14,706	$13,750	$5,775	$4,500	$10,000	$4,500	$8,500
Total Plant Cost (TPC)	$92,129	$239,468	$228,475	$176,150	$101,600	$164,850	$101,600	$147,600
OPERATING EXPENSES								
FIXED O&M - $/kW-yr	$37.2	$26.8	$26.8	$26.8	$37.2	$37.2	$37.2	$37.2
Replacement Battery Costs - $/kW	$735	$1,471	$1,375	$578	$900	$2,000	$900	$1,700
Battery replacement - yrs	8	8	8	8	8	8	8	8
Variable O&M - $/kWh (Charging or Discharging)	0.0027	0.0014	0.0027	0.0018	0.0050	0.0018	0.0046	0.0017

Table B-31. Li-ion Battery Systems for Commercial and Residential Applications

(Parameters noted in black are vendor inputs.)

Application	**Commercial & Industrial**	**Commercial & Industrial**	**Commercial & Industrial**	**Commerical & Industrial**	**Commerical & Industrial**	**Commerical & Industrial**	**Commerical & Industrial**
Technology Type	**Adv. Li-ion**	**Li-ion**	**Li-ion**	**Li-ion**	**Li-ion**	**Li-ion**	**Li-ion**
Supplier	**S6**	**S25**	**S19 - 1**	**S7**	**S7**	**S7**	**S7**
Survey Year	2010	2010	2010	2011	2011	2011	2011
DESIGN BASIS - General							
System Capacity - Net kW	50	50	50	100	200	250	500
Hours of Energy storage at rated Capacity - hrs	4	2	3	4	4	4	2
Depth of Discharge (DOD) per cycle - %	85%	80%	80%	100%	100%	100%	100%
Energy Capacity - kWh @ rated DOD	200	100	150	400	800	1,000	1,000
Energy Capacity - kWh @ 100% DOD	235	125	188	400	800	1,000	1,000
Auxiliaries - kW							
Unit Size - Net kW	50		50	100	200 kW	250	500
Number of Units - #	6	Pad mounted	1	1	1	1	1
Physical Size - SF/Unit	24		1				
System Foot Print - SF	26.4		4X4	336	693	693	693
System Weight - lbs	654.368		5,000		44,000		
Round Trip AC / AC Efficiency - %	89%	93%	80%	90%	90%	90%	90%
Number of cycles / year	365	365	365	365	365	365	365
GENERAL - Timing							
Commercial Order Date				2010.12			
Plant Life, yrs	15	15	15	15	15	15	15
TOTAL PLANT COST							
$/kW	$4,789	$4,570	$3,523	$5,804	$5,924	$5,464	$3,034
$/kWh @ rated DOD	$1,197	$2,285	$1,174	$1,451	$1,481	$1,366	$1,517
$/kWh @ 100% DOD	$1,018	$1,828	$939	$1,451	$1,481	$1,366	$1,517
PLANT CAPITAL COST							
Power - $/kW	$1,407	$1,407	$1,896	$2,173	$2,314	$1,859	$1,231
Storage - $/kWh @ rated DOD	$846	$1,581	$542	$908	$902	$901	$901
SYSTEM COSTS - Equipment & Install	Actual Cost	Actual Cost	Actual Cost	Projected Cost	Actual Cost	$/kWh	$/kWh
ES System							
ES Equipment	$147,059	$137,500	$57,750	$312,000	$624,000	$780,000	$780,000
ES Installation	$7,353	$6,875	Included	$15,600	$31,200	$39,000	$39,000
Enclosures	$2,350	$2,350	Included	$30,048	$50,080	$50,080	$50,080
Owner Interconnection							
Equipment	$44,500	$44,500	$44,500	$79,000	$131,500	$131,500	$233,500
Installation	$22,500	$22,500	$22,500	$39,500	$33,000	$33,000	$58,500
Enclosures	Included	Included	included	included	included	included	included
System Packing	$0	$0	$9,000	$0	$0	$0	$0
System Shipping to US Port	$0	$0	$17,813	$4,322	$4,322	$4,322	$4,322
Utility Interconnection							
Equipment	$250	$250	$250	$250	$62,900	$62,900	$70,400
Installation	$250	$250	$250	$250	$62,900	$62,900	$70,400
Site BOP Installation (Civil Only)	$500	$500	$18,313	$43,500	$72,500	$72,500	$72,500
Total Cost Equipment	$194,159	$184,600	$129,313	$425,620	$872,802	$1,028,802	$1,138,302
Total Cost Installation	$30,603	$30,125	$41,063	$98,850	$199,600	$207,400	$240,400
General Contractor Facilities at 15% install	$0	$0	$0	$14,828	$29,940	$31,110	$36,060
Engineering Fees @ 5% Install	$0	$0	$0	$4,943	$9,980	$10,370	$12,020
Project Contingency Application @ 0-15% install	$0	$0	$0	$4,943	$9,980	$10,370	$12,020
Process Contingency Application @ 0-15% of battery	$14,706	$13,750	$5,775	$31,200	$62,400	$78,000	$78,000
Total Plant Cost (TPC)	$239,468	$228,475	$176,150	**$580,383**	**$1,184,702**	**$1,366,052**	**$1,516,802**
OPERATING EXPENSES							
FIXED O&M - $/kW-yr	$26.8	$26.8	$26.8	$23.7	$16.5	$13.2	$11.7
Replacement Battery Costs - $/kW	$1,471	$1,375	$578	$1,560	$1,560	$1,560	$780
Battery replacement - yrs	8	8	8	5	5	5	5
Variable O&M - $/kWh (Charging or Discharging)	0.0014	0.0027	0.0018	0.0014	0.0014	0.0014	0.0027

APPENDIX C: SAMPLE PROCUREMENT DOCUMENTS

Appendix C: Table of Contents

Appendix C: List of Figures and List of Tables

(none)

SAMPLE PROCUREMENT DOCUMENTS

The following RFI was used in the recent procurement of a storage system at a KIUC substation to provide three services to the grid: mitigate the intermittency of a nearby 3-MW PV plant, regulate distribution bus voltage, and provide frequency support during an outage. KIUC chose to illustrate the expected duty cycle of the battery in response to the grid requirements. The KIUC RFI also provided a one-line diagram of the substation, its schematic layout, and an aerial photograph of the intended location. All these pieces of information collectively facilitate the understanding of the intended use of the storage system by prospective vendors. The subsequent RFP for this storage system acquisition by KIUC is also shown to illustrate the kind of information included in an RFP.

The sample RFI and RFP are used with written permission from KIUC.

C.1 Sample RFI

KIUC RFI for Demonstration of an
Energy Storage System on an Islanded System
Version 2.01 – August 26, 2010

Overview

The Island of Kauai is the fourth largest inhabited Hawaiian Island. It is roughly circular, and approximately 555 square miles in size and 26 miles across at its widest points. Kauai's de-facto population is 65,000 with the majority of its economy based on tourism and agriculture-related businesses. Currently, Kauai Island Utility Cooperative (KIUC) is the only franchised provider of electric service to its consumers on the Island of Kauai. KIUC is a standalone vertically integrated electric utility and as such, provides all of the facilities, equipment and personnel required to meet the power generation, transmission, and retail distribution needs of its consumers. KIUC's all time peak load is 78 MW's, serving approximately 35,000 meters over 13 substations by means of three active generating sites.

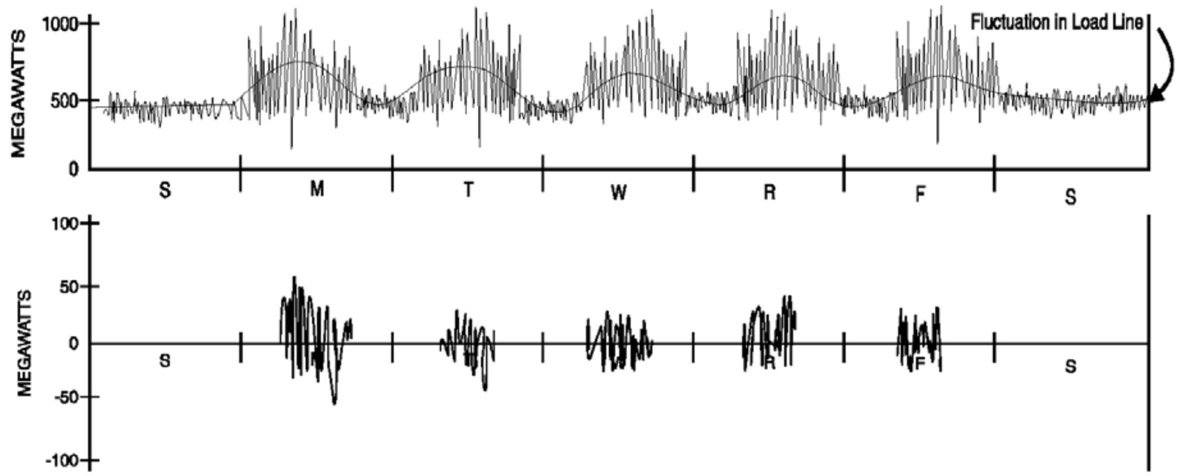
KIUC has determined that it could achieve substantial benefits by deploying a battery energy storage system (BESS) on its system. Such benefits would include the potential to firm up intermittent renewable resources and mitigate other undesirable effects of integrating such resources into KIUC's relatively small system. In order to test the BESS concept, a demonstration project is being pursued on a small-scale basis.

Project Conceptual Description

KIUC has selected Koloa Substation to demonstrate a BESS, which will be used to mitigate intermittent fluctuations of a 3 MW PV array, regulate the distribution bus voltage, serve as spinning reserve, and provide frequency support during the loss of generation. The 3 MW PV system is located approximately 1 mile from Koloa Substation and will tie in over a dedicated 12.47 kV distribution circuit. The proposed BESS and PV system will interconnect at a dedicated 12.47kV breaker in the substation yard. Koloa Substation has an approximate annual peak demand of 9.4 MW and feeds the South Shore loads over 4 independent 12.47 kV distribution feeders.

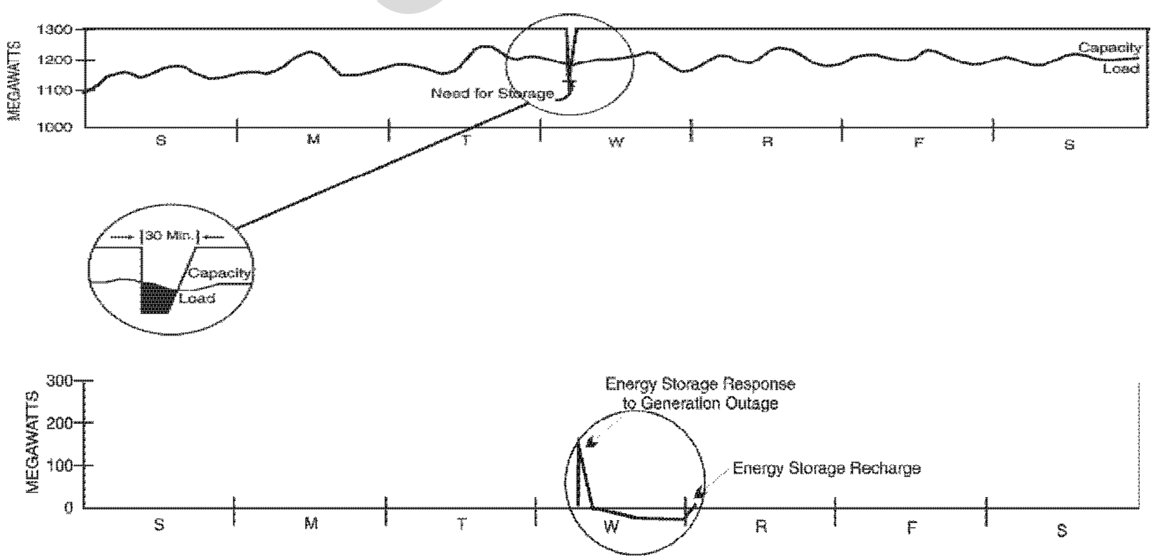
Requirements

1. Defined purpose of the storage system
    a. Regulate output of PV system ***<u>(Below is a visual representation only – MW and Duration values are not valid)</u>***



b. Provide voltage support for 12.47 kV distribution bus
c. Contingency reserve for use during generation shortage. 1/week
d. Charging Sources
    i. PV charging
    ii. KIUC generation
e. Charging Schedule
    i. Minimum state of charge specified by vendor
    ii. Manually triggered state of charge by KIUC system operator within vendor specified limits
f. Provide frequency support during loss of generation or system disturbance. 1/week

(Below is a visual representation only – MW and Duration values are not valid)

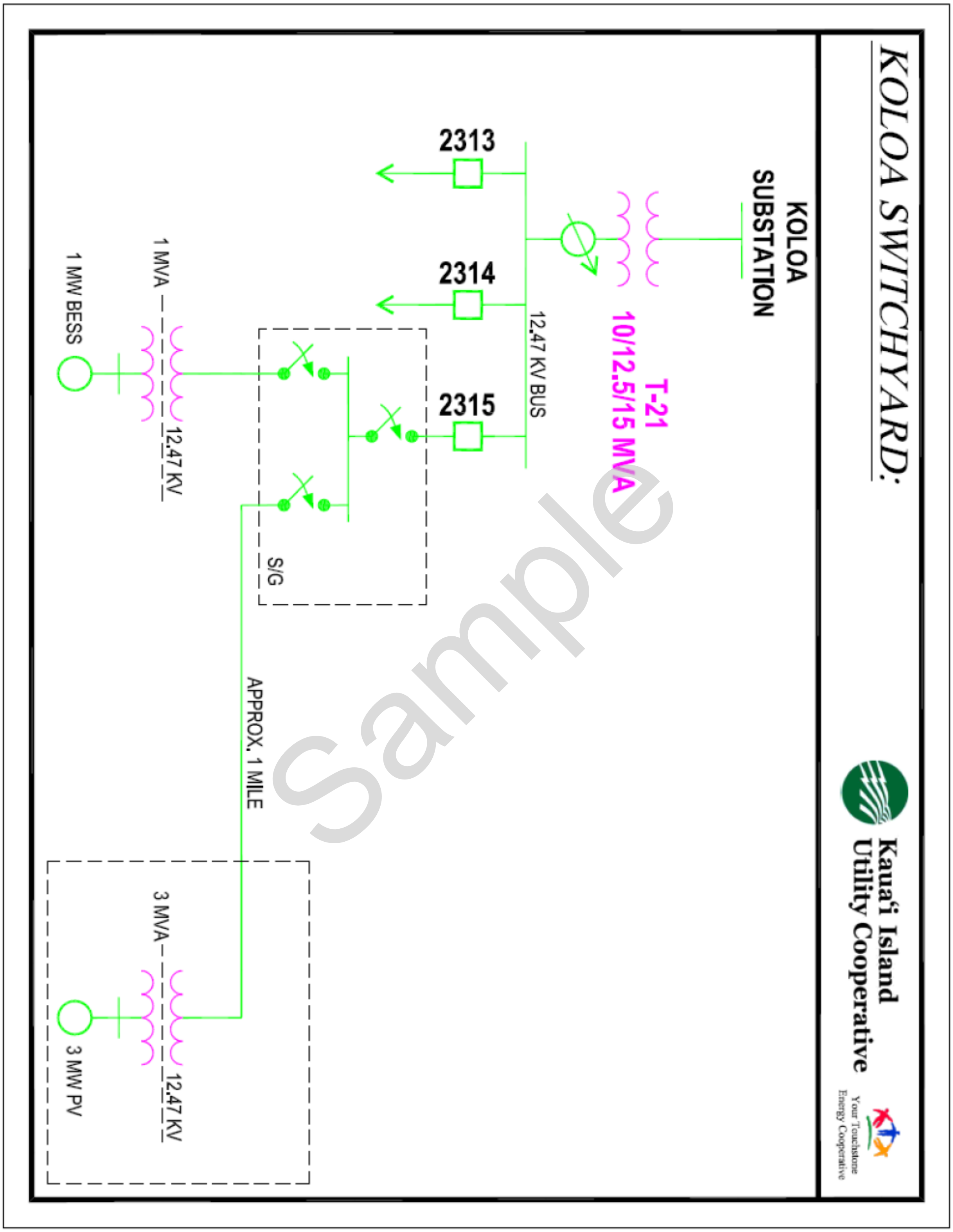


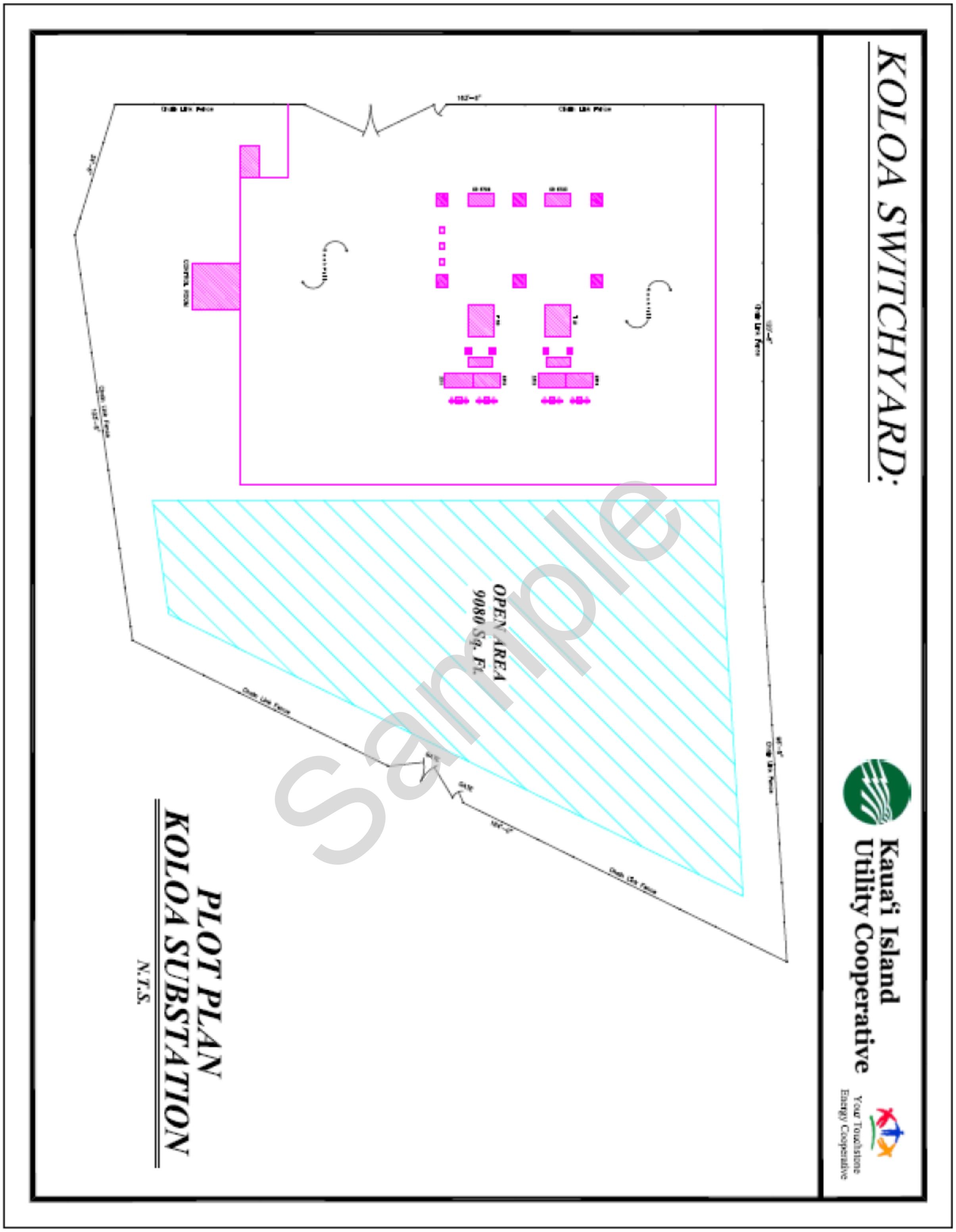
   g. Size estimate of system: Minimum 1000 kW, 700-1000 kWH
   h. Discharge durations required: Full power, 15-30 minutes, 1/week
   i. Estimated number of shallow discharges: 70% power, up to 2 minutes, 50/day

2. Usable Space and Location
   a. Koloa One-line conceptual (see attached drawing)
   b. Aerial view (see attached photo)
   c. Approximate dimensions (see attached drawing)
3. BESS Physical Requirements
   a. 55-100 degrees F
   b. Earthquake zone Class 1
4. Control System Requirements
   a. Integrate with existing Areva SCADA/AGC and Harris D-20 substation RTU
   b. HMI in substation control house to show status and alarms of BESS
   c. Dispatched by KIUC
5. Environmental and Hazardous Materials
   a. RFI response will identify any special environmental handling or containment needs, including hazardous material and fire protection requirements for operation and maintenance of the BESS. KIUC will obtain all necessary permits and approvals for the BESS.
6. End-of-Life Decommissioning and Disposal
   a. RFI responses must include a discussion of how the storage system will be decommissioned at its end-of-life and its eventual recycling and/or disposal.
7. Duration of desired warranty
   a. 8 years
8. Vendor to discuss maintenance and support options
9. Vendor to discuss alternative finance and ownership structures if available
10. Vendor to estimate electrical and physical size of the BESS and provide non-binding cost estimate
11. Vendor to discuss Manufacturing/Production capabilities and estimated lead times for delivery

Schedule

- Intent to Respond: By September 1, 2010 vendor must indicate their interest and establish themselves by emailing jpcox@kiuc.coop. The e-mail subject line should read, "(company name) intends to respond for BESS RFI".
- KIUC will hold conference call 2 weeks after RFI issued to respond to questions.
- Formal Responses due 3 weeks after conference call.
- Proprietary Information: Careful consideration should be given before confidential information is submitted to KIUC. The bidder should determine whether the information is critical for evaluating a proposal, or whether general, non-confidential information, may be adequate for review purposes. KIUC will honor, to the extent permissible by the State of Hawaii, County of Kauai, and Federal law, any information that the bidder submits that is identified and labeled as "Confidential" or "Proprietary". This information should include a written request to exempt it from disclosure including a written statement of the reasons why the information should be exempted
- This RFI does not commit KIUC to award a contract, pay any costs incurred in preparing a proposal, to procure or contract for services. KIUC reserves the right to accept or reject any or all proposals, to negotiate with all qualified sources, or to cancel in part or in its entirety this RFI. KIUC also reserves the right to waive or modify minor irregularities in proposals received and to eliminate mandatory requirements.


KOLOA SWITCHYARD:
KOLOA SUBSTATION
T-21
10/12.5/15 MVA
2313
2314
2315
12.47 KV BUS
S/G
1 MVA
12.47 KV
1 MW BESS
APPROX. 1 MILE
3 MVA
12.47 KV
3 MW PV
Kaua'i Island Utility Cooperative
Your Touchstone Energy Cooperative
Sample


KOLOA SWITCHYARD:
OPEN AREA
9080 Sq. Ft.
Kaua'i Island Utility Cooperative
Your Touchstone Energy Cooperative
PLOT PLAN
KOLOA SUBSTATION
N.T.S.
Sample


Sample

C.2 Sample RFP

REQUEST FOR PROPOSAL (RFP)

<table>
<tr><td colspan="3">Project
KIUC Energy Storage</td><td>Date RFP Issued
10/18/2010</td></tr>
<tr><td colspan="3">Email Address Supplier to Submit Proposal
jpcox@kiuc.coop</td><td>Date Proposal Due
11/8/2010</td></tr>
<tr><td>Sole Point-of-Contact at KIUC
John Cox</td><td>Phone Number
808-246-8205</td><td>Fax Number</td><td>Email</td></tr>
</table>

1. Introduction

KIUC is requesting that certain contractors ("Contractors") submit a Proposal ("Proposal") to perform the Services as set forth and described herein pursuant to the terms and conditions of this Request for Proposal. This Request for Proposal ("RFP") is neither a contract nor an offer. Contractors shall not receive any rights whatsoever from submitting a Proposal.

If a Contractor *does not have* an *existing agreement* with KIUC which covers performance of the Services, the Contractor should review KIUC's standard agreement. Any Proposal submitted by such Contractor shall represent a firm offer to contract for performance of the Services on the terms and conditions described in said standard agreement unless Contractor includes its explicit objections to such terms and conditions within the Proposal. However, if a Contractor *has* an *existing agreement* with KIUC which covers performance of the Services, the terms and conditions of such existing agreement shall govern the Services. If required by such existing agreement, the Contractor shall execute an Individual Task Authorization ("ITA") for the Services.

By submitting a Proposal, Contractor is (i) making a firm offer to perform the Services as set forth and described herein pursuant to the terms and conditions of this Request for Proposal, (ii) agreeing that the Proposal shall be valid for 90 calendar days unless Contractor explicitly states otherwise in the Proposal, (iii) agreeing that KIUC may, in its sole discretion, accept or reject, in whole or in part, any Proposal, (iv) agreeing that KIUC has sole discretion in selecting a Contractor for the Services and (v) agreeing that KIUC may, in its sole discretion, discontinue negotiations at any time prior to execution of an agreement or ITA which covers the Services.

Specifically in regards to this RFP, Contractor shall (i) bear all costs and expenses that it incurs, (ii) limit all communication to the "Sole Point-of-Contact" identified above and (iii) submit all questions to the Sole Point-of-Contact's email address identified above. Additionally, Contractor shall not (i) rely on any oral representation or oral modification made by the Sole Point-of-Contact or (ii) rely on any representation made by someone other than the Sole Point-of-Contact.

KIUC may reject any Proposal not received by the "Date Proposal Due" identified above. KIUC will make a reasonable effort to respond to all questions within two business days of receipt. KIUC will share with other Contractors any question and subsequent response which KIUC determines, in its sole discretion, to be important to a Contractor's ability appropriately respond to this RFP.

2. General

The Island of Kauai is the fourth largest inhabited Hawaiian Island. It is roughly circular, and approximately 555 square miles in size and 26 miles across at its widest points. Kauai's de-facto population is 65,000 with the majority of its economy based on tourism and agriculture-related businesses. Currently, Kauai Island Utility Cooperative (KIUC) is the only franchised provider of electric service to its consumers on the Island of Kauai. KIUC is a standalone vertically integrated electric utility and as such, provides all of the facilities, equipment and personnel required to meet the power generation, transmission, and retail distribution needs of its consumers. KIUC's all time peak load is 78 MW's, serving approximately 35,000 meters over 13 substations by means of three active generating sites.

KIUC has determined that it could achieve substantial benefits by deploying a battery energy storage system (BESS) on its system. Such benefits would include the potential to firm up intermittent renewable resources and mitigate other undesirable effects of integrating such resources into KIUC's relatively small system. In order to test the BESS concept, a demonstration project is being pursued on a small-scale basis.

3. Project Description

KIUC has selected Koloa Substation to demonstrate a BESS, which will be used to mitigate intermittent fluctuations of a 3 MW PV array, regulate the distribution bus voltage, serve as spinning reserve, and provide frequency support during the loss of generation. The 3 MW PV system is located approximately 1 mile from Koloa Substation and will tie in over a dedicated 12.47 kV distribution circuit. The proposed BESS and PV system will interconnect at a dedicated position in the substation yard. Koloa Substation has an approximate annual peak demand of 9.4 MW and feeds the South Shore loads over 4 independent 12.47 kV distribution feeders.

4. Proposal Process and Schedule

KIUC intends to select a Contractor for the turnkey BESS project and negotiate a final scope of work with the selected Contractor. Proposals will be solicited from potential BESS Contractors based on these technical specifications and documents.

KIUC will select a short list of no more than two Contractors from these proposals. Meetings will be scheduled between KIUC and the Contractor's proposed technical project personnel to discuss the details of the Contractor's proposal and to clarify the intent of the specifications. Clarifications to the specification may be required based on these meetings. Following these meetings, the short listed Contractors will submit a revised proposal. From these revised proposals, KIUC will select a preferred Contractor and enter into negotiations for a final scope of work.

The anticipated schedule for the BESS project is as follows:

Specifications Issued for Bids	October 18, 2010
Bids Due	November 8, 2010
Shortlist Selection and Onsite Meetings	November 15 – December15, 2010
Selection of Contractor and Negotiation of Final Scope	January 10, 2011
BESS on-line	June 15, 2011
Final Acceptance	July 1, 2011

5. Scope of Work

The scope of supply for the BESS shall include the following principal elements. The Contractor shall be responsible for identifying and providing any and all other additional equipment, components, and services necessary to install a fully functional BESS.

- Design, fabricate, ship, assemble, test, startup, commission, warrant and make ready for service a fully functional turnkey BESS that meets or exceeds all requirements delineated herein up to the BESS step-up transformer, and auxiliary AC station service
- Design, install and make ready for the electrical connection from the BESS to the step-up transformer. KIUC will provide the 480V/12.47kV step up transformer. Contractor is responsible for 480V connections, conduit, cable, and protection, back to BESS.
- Design, install and make ready for the communication connection from the BESS to the Harris D-20 located in Koloa substation control house

- Provide all documentation including calculations, software, design drawings, equipment drawings, and modifications to the existing drawings
- Provide on-site training classes for KIUC operators, engineers, technicians and maintenance personnel
- Supply any special equipment and tools required for the operation and maintenance of the project
- Supply an initial complement of spare parts
- Provide a warranty for all BESS components
- Submit for KIUC review and comment all design drawings, O&M manuals, and miscellaneous documentation required to provide a complete installation
- Provide and maintain a Schedule for all design, fabrication, installation and testing activities for the project, including KIUC review periods

6. Documentation

The Contractor shall furnish complete documentation that will be used for determination of contract compliance, as well as, operation and maintenance of the BESS. The documentation shall be in English, well detailed and instructive.

At a minimum, Contractor's documentation shall consist of the following:

- Construction Materials Submittal
- Equipment Drawings and Specifications
- Bill of Material
- Protective relay and BESS Control Settings
- Operation and Maintenance Manual
- Maintenance Schedule
- Project Schedule
- Software Documentation
- Test Reports

The Contractor shall submit all final design and record drawings in digital form. In addition to the specified drawing requirements, all construction and installation drawings pertaining to architectural, civil, mechanical and electrical activities, bills of materials, interconnection, wiring, and cable diagrams shall be included. All equipment drawings that may be subjected to revisions or modification shall also be included. The format shall be AutoCAD Version 14.

7. Design Conditions

- Design Temperature Range: min 55 F, max 100 F
- Peak Wind Gust: 110 mph
- Seismic Zone: 1

8. Electrical Design Parameters

- Nominal voltage at Koloa Distribution Bus = 12.47 kV (1.0 pu)
- Normal sustained voltage at Koloa Distribution Bus = 0.95 pu (min) and 1.05 pu (max)
- Normal frequency = 60 Hz with normal deviation of +/- 0.2 Hz
- Emergency frequency swings = 55.0 Hz (min) and 65 Hz (max)

9. Audible Noise

The maximum sound level generated from the BESS system and any associated equipment supplied by the Contractor under any output level within the BESS operating range, shall be limited to 65 dBA at 50 feet in any direction from the substation fence.

10. BESS Power and Energy Ratings

- 1000 kW / 1000 kWh minimum - 1500 kW / 1000 kWh maximum
- Full power discharge, 30 minutes, 1/week

- Shallow discharge, 70% power for 2 minutes, 50 times/day

11. Modes of Operation

3MW PV Smoothing

The BESS shall manage (smooth) output of the 3MW PV array. The overall net power import or export of the mutually coupled BESS and 3 MW PV array shall not adversely affect KIUC system stability, reliability, or operational activities. Operation in this mode will be automatically initiated by detection of active power flow from 3 MW PV array. KIUC will provide A, B, and C phase Currents and Voltages to the BESS Control.

- CT inputs (ratio 300:5) from the PV array to the BESS Control
- PT inputs (ratio 60:1) from the from the Koloa 12.47kV Distribution bus to the BESS Control

Spinning Reserve

The BESS shall be capable of discharging up to full rated output at any time in accordance with performance criteria specified herein. Operation in this mode will be initiated by detection of low frequency or frequency rate of change while the BESS is in any other mode, including charging. Spinning reserve will be initiated when system frequency drops to a KIUC selectable setpoint and shall load to full output, or as required to arrest frequency decay. Once a spinning reserve event is initiated, the frequency control shall control the BESS output as the system recovers to 60 Hz. After a spinning reserve discharge, the BESS shall return to the mode in which it was operating at the start of the spinning reserve discharge, as allowed by the battery's state of charge at that time. If the discharge limit will not allow resumption of previous operation mode, the BESS shall go to the charge mode. Spinning reserve shall have the highest priority of all modes contained in this specification. All other modes may be interrupted for a spinning reserve event.

Automatic Scheduling

In order to take advantage of the fast response time possible with the BESS, KIUC desires the BESS to be capable of ramping to a predetermined output level as set by a remote signal from KIUC's SCADA system. The ramp rate and output level shall be selectable and the output level shall be programmable, on a continuous real time basis, by the remote signal from KIUC's SCADA system. Once initiated in this operating mode, the BESS shall remain at the designated output until terminated by a remote signal or the Contractor specified discharge limit is reached. Operation in this mode may be interrupted for a spinning reserve event as allowed by the battery's state of charge at that time.

Automatic Generation Control

The BESS shall be capable of Automatic Generation Control (AGC) similar to that of rotating machinery. The BESS output will be controlled by a remote signal from the AGC. The BESS voltage and frequency controls shall regulate the output based on appropriate KIUC selectable droop settings. The operation in the AGC mode shall be limited by the Contractor specified discharge limit for the batteries. Operation in the AGC mode may be interrupted by system disturbances requiring automatic emergency support from the BESS, as allowed by the battery's state of charge at that time.

Power System Stabilizer

The BESS shall provide effective damping of power system oscillations. Such oscillations may be caused by system disturbances, primarily line faults and the sudden loss of generation. The BESS shall be capable of detecting such oscillations by monitoring frequency and voltage deviations and controlling the BESS output to provide effective damping. The power system stabilizer shall be capable of being enabled or disabled by a remote signal.

VAR Support

The BESS will be required to provide VAR support for voltage regulation at the Koloa substation 12.47kV bus under steady state operating conditions. The BESS voltage regulator controls shall include a selectable setpoint, via SCADA, on the Koloa 12.47 kV distribution bus. BESS capacity for VAR support shall be a lower priority than all other described operating modes. The VAR output of the BESS may be limited based on remaining capacity used for real power output.

12. Monitoring/Alarms

The monitoring/alarm system or procedures shall alert KIUC, via SCADA, when the number of failed or inadequately performing cells or other Contractor determined conditions indicate that;

- Preventative maintenance should be performed to keep the BESS at the specified performance levels.
- The BESS is in imminent danger of failing to meet specified performance levels or potential safety hazards exist.
- The BESS can no longer meet the specified performance criteria or safety hazards exist.

The Contractor shall include, in the Operation and Maintenance Manual, the recommended corrective action and maintenance procedures for each alarm level or observed condition provided.

13. Harmonics

The BESS must meet the harmonic specifications of IEEE 519.

14. Protection Requirements

A complete protective relaying system based on prudent industry practices shall be a part of the AC system. The protective relaying and metering shall be integrated with the BESS control system and communications channel to KIUC's SCADA system. All protective equipment and schemes shall be properly coordinated with the protection of the Koloa Substation. Information on the protective relaying system for the Koloa Substation will be provided to the successful Contractor.

15. Controls

The BESS control system shall be designed to provide for automatic, unattended operation of the BESS. However, the control system design also shall provide for local manual operation, remote operation, or dispatch of the BESS from KIUC's SCADA system. All modes of operation and its operational set-point functionality shall be remotely adjustable from SCADA to allow change in settings and to turn on/off all controls or modes when appropriate.

16. SCADA Integration

The Contractor's design and BESS control system interface shall be integrated with KIUC's existing SCADA system and associated RTU/substation communication network. The interface point will be to a GE D20 Remote Terminal Unit (RTU) located in the Koloa substation control house. Existing RTU hardware is available and useful, depending on final design, for interfacing to the new BESS control system into KIUC's SCADA system.

The engineering tasks shall include, but not be limited to, the following:

- (KIUC to provide conduit and communication cabling from RTU to BESS Control. Alphawire 3232 (3/C 20AWG Shielded) or Belden 3107A (2PR/22AWG Shielded) will be utilized.)
- Communication between BESS and RTU equipment will be RS-485/Serial. Depending on final design (e.g., amount of monitored devices, equipment layout, distance, etc.), other communication methods may be recommended for approval that will provide the most efficient, reliable, and secure communication network. All signal/communication cable to be shielded to ensure signal integrity.
- DNP3 protocol to be utilized for all communications between BESS control system interface and RTU.
- DNP3 map of all I/O points and controls on local BESS control system HMI interface must be available and inclusive to SCADA system for monitoring and control.
- Additional and identifiable points or controls, if not provided initially through BESS control system interface base offering, must be programmed into interface for serial link communications (e.g., but not limited to, fire system activation & integrity, BESS building entry, breaker status).

- A provided SCADA points list shall be prepared by the Contractor and submitted to KIUC for review and approval.
- BESS control system interface will have the ability to accept AGC control setpoint signals from SCADA master station via RTU.
- Contractor will help facilitate and ensure all BESS sensor calibrations and system testing to KIUC SCADA.
- Provide monitoring access and control access to all proposed BESS modes of operation, state of charge, available duration at various output levels, kW/kVar setpoints, kW/kVar flow, local/remote control, misc BESS alarms/status.
- Work items shall include all labor, materials, test equipment, & engineering required to complete SCADA communication integration.
- The Contractor shall prepare plan and section drawings for the SCADA/RTU integration showing the location of all equipment and conduit runs. The Contractor showing all external cable connections to the applicable BESS switchboards and other equipment shall prepare interconnection wiring diagrams for the RTU.
- The Contractor shall provide complete testing procedures for the BESS equipment and control system and assist KIUC in the commissioning of the RTU/SCADA integration. The prepared testing procedures shall be submitted to KIUC for review and approval before any testing work is done. A final report detailing the work completed, all test forms, and any marked-up drawings shall be submitted to KIUC..

17. Grounding

A suitable equipment grounding system shall be designed and installed for the BESS system. This system shall be tied to the Koloa Substation grounding system. The grounding system shall provide personnel protection for step and touch potential in accordance with IEEE 80. The system also shall be adequate for the detection and clearing of ground faults. The Contractor shall determine, design and install the required interconnections between the BESS and Koloa substation grounding systems.

18. Civil/Structural

The Contractor shall furnish all labor, equipment, materials and services to layout, design and construct all foundation and concrete work required for a complete and operable facility. All BESS required foundations and structures shall be designed by a qualified registered professional engineer or registered architect as applicable. All final (Issued for Construction) drawings, specifications and calculations shall be wet-stamped by a Registered Civil/Structural Engineer or Architect as applicable. The Contractor is responsible for Geotechnical surveying.

19. Spill Containment

The BESS design shall mitigate against electrolyte spills that are credible for the types of cells used. The design shall include features that contain electrolyte spills (to be emptied by contracted chemical disposal company in the event of a spill) and prevent discharge to surrounding site soils.

20. Personnel Safety

The BESS shall include eyewash stations in the battery area as applicable.

21. Fire Protection

The Contractor shall design and install a fire protection system that conforms to national and local codes. The fire protection system design and associated alarms shall take into account that the BESS will be unattended at most times.

22. Spare Parts and Equipment

The Contractor shall evaluate its design with regard to failure rates, effects and BESS reliability. The Contractor shall provide a recommended spare parts list, including prices and availability, as part of his proposal.

23. Factory Testing - Battery

The Contractor shall test and submit test data for the cells designated for use on this project. At a minimum, the following tests shall be performed.

- Capacities, Amphour and Watthour
- Heat Generated
- Efficiencies
- As applicable, maximum noxious and toxic material release rates

The Contractor shall capacity test 100% of the production cells to ensure compliance with design requirements. The Contractor may propose optional alternate testing programs that result in a benefit to KIUC. However, the base proposal shall include capacity testing of 100% of the cells. All proposals for alternate testing shall include details of the proposed plan and the cost benefit to KIUC.

24. Acceptance and Performance Testing

The Contractor shall develop and perform field testing procedures to assure that the BESS will perform as designed and that the system meets the performance criteria specified elsewhere in these specifications. All modes of operation as described in these specifications shall be tested. The Contractor shall determine that the BESS is fully operational and suitable for acceptance testing witnessed by KIUC. The Contractor shall document all acceptance and performance tests performed. The Contractor shall submit documentation, analyses, and a summary in a test report for KIUC's records. The acceptance test procedure will be developed by the Contractor and shall demonstrate to KIUC that the BESS is operational and performs as specified. These tests shall include, as a minimum:

- Verification of sensors, metering and alarms
- Verification of all control functions, including automatic, local and remote control
- Verification of performance criteria

25. Warranty

Contractor warrants KIUC that the equipment and materials furnished hereunder and the completed BESS Project are fit for the purpose of producing electricity in accordance with the Contract and are free from defects in workmanship and materials. Contractor makes all such warranties for a period of eight (8) years after the date of acceptance of the Project by KIUC.

26. Exceptions

All exceptions and/or deviations shall be clearly and separately itemized. It shall not be necessary for KIUC to examine the standard literature and documents of suppliers to determine the existence and extent of any exceptions and/or deviations from this specification.

Kauai Island Utility Cooperative
Battery Energy Storage System
Proposal Data Checklist

- ☐ Provide firm-fixed pricing being offered in accordance with Bidder's form.
- ☐ Provide drawings showing proposed layout of all outdoor equipment in relation to the BESS and the Koloa Substation.
- ☐ Provide a detailed project schedule.
- ☐ Provide Warranty terms and conditions and information for 8 year warranty.
- ☐ Provide list of recommended spare parts and prices.
- ☐ Provide list of exceptions and clarifications to the technical proposal and commercial terms and conditions, or written verification that no exceptions or clarifications are taken.
- ☐ Provide a description of all required maintenance activities, including estimated man-hours and frequency of occurrence for each activity.
- ☐ Provide information on AC/AC round trip efficiencies (excluding step-up transformer).
- ☐ Provide proposed battery replacement schedule.
- ☐ Provide battery replacement costs and a description of escalation factors used to determine actual battery costs at the time of replacement.
- ☐ Provide information on battery replacement procedure, including estimated time to complete replacement.
- ☐ Provide information showing the length of time the battery can maintain constant output at demand levels less than rated output.
- ☐ Provide information showing the length of time the battery can maintain rated output at a reduced state of charge.
- ☐ Provide information on guaranteed life expectancy to maintain rated capacity as number of discharges or total energy delivered varies.
- ☐ Provide information on the controlling parameters that determine life expectancy for the proposed system.
- ☐ Provide information on required environmental conditions or maintenance procedures (if any) that performance guarantees are based on.
- ☐ Provide overload capability of the proposed BESS.
- ☐ Provide PCS manufacturer specifications.
- ☐ Provide information on how the charging cycle changes as maximum demand is reduced.
- ☐ Provide information on the state of charge of the battery as a function of time during the charge cycle.
- ☐ Provide proposed factory and acceptance test plans to include performance and "Modes of Operation" testing.
- ☐ Provide a performance curve indicating # of cycles vs. depth of discharge.

Kauai Island Utility Cooperative
Battery Energy Storage System
Bidder's Proposal

1. Project Management	$ ____________________
2. Battery	$ ____________________
3. Power Conversion System	$ ____________________
4. Balance of Outdoor Equipment	$ ____________________
5. Construction and Installation	$ ____________________
6. Protective Equipment	$ ____________________
7. BESS Control and Metering System	$ ____________________
8. Fire Protection System	$ ____________________
9. Start-up, Testing, Commissioning	$ ____________________
10. SCADA Integration	$ ____________________
11. Warranty	$ ____________________
12. Shipping: FOB Koloa Substation	$ ____________________
13. Miscellaneous (list details)	$ ____________________
TOTAL BESS PRICE	$ ____________________
14. End of Life Decommissioning	$ ____________________
15. Spare Parts and Equipment	$ ____________________
16. Extended Warranty	$ ____________________
TOTAL ADDITIONAL COSTS	$ ____________________

Exhibit 1

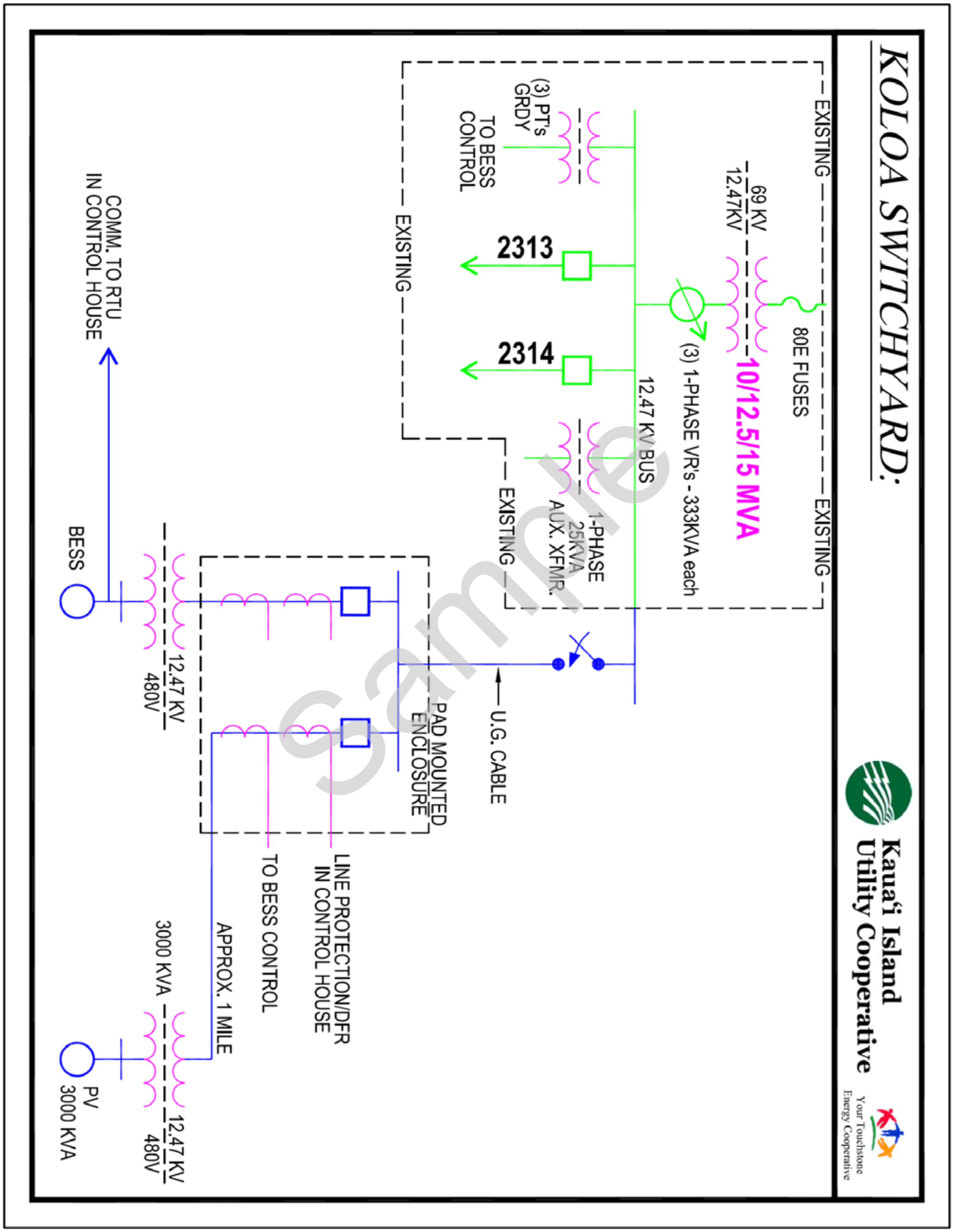

KOLOA SWITCHYARD:
Kaua'i Island Utility Cooperative
Your Touchstone Energy Cooperative
EXISTING
80E FUSES
69 KV
12.47KV
10/12.5/15 MVA
(3) 1-PHASE VR's - 333KVA each
12.47 KV BUS
(3) PT's GRDY
TO BESS CONTROL
2313
2314
1-PHASE 25KVA AUX. XFMR.
U.G. CABLE
PAD MOUNTED ENCLOSURE
LINE PROTECTION/DFR IN CONTROL HOUSE
TO BESS CONTROL
APPROX. 1 MILE
COMM. TO RTU IN CONTROL HOUSE
BESS
12.47 KV
480V
3000 KVA
PV
3000 KVA
Sample

Exhibit 2

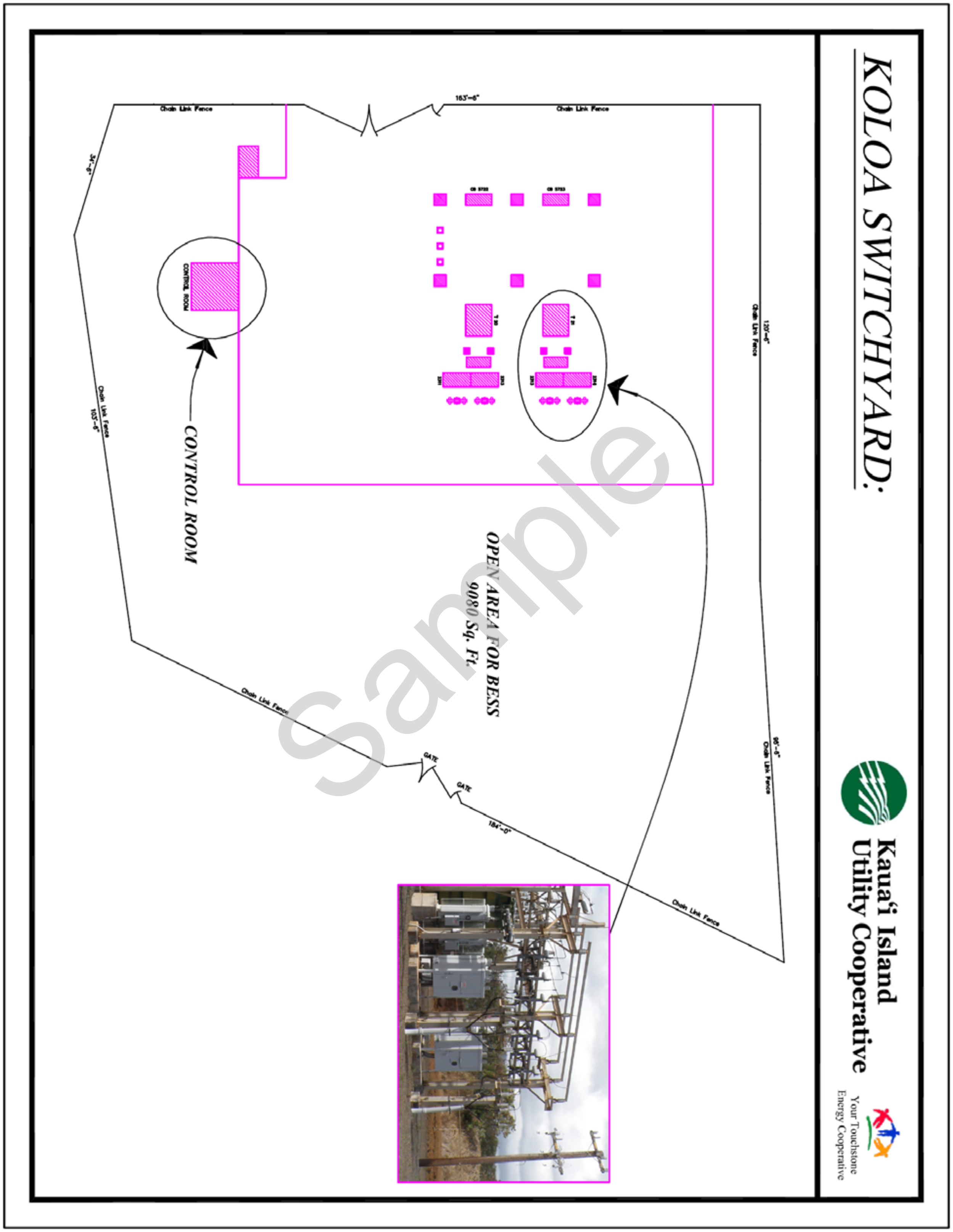

KOLOA SWITCHYARD:
CONTROL ROOM
OPEN AREA FOR BESS
9080 Sq. Ft.
Chain Link Fence
Kauaʻi Island Utility Cooperative
Your Touchstone Energy Cooperative
Sample

Exhibit 3


KOLOA SWITCHYARD:
AREA FOR BESS
12.47KV BUS
36'
40'
ACCESS
CONTROL ROOM
Kaua'i Island Utility Cooperative
Your Touchstone Energy Cooperative
Sample

C.3 Technical Specification Example

An example of a technical specification for procurement of an electricity storage system is EPRI's "Technical Specification for a Transportable Lithium-Ion Energy Storage System for Grid Support Using Commercially Available Lithium-Ion Technology." This specification can be found at:

http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025573

C.4 Sample Data Requirements Document Outline (Provided by PNM)

The following is a possible outline for a Requirements Document:

1. Project Introduction
    a. Opportunity Description
    b. Business Need
    c. Justification
    d. Project Objectives
    e. In Scope
    f. Out of Scope
    g. System Context
    h. Stakeholders and Users
    i. Risks
    j. Assumptions
    k. Constraints
2. Functional Requirements
    a. System Functionality
3. Non-Functional Requirements
    a. Look & Feel Requirements
    b. Usability Requirements
    c. Performance Requirements
    d. Operational Requirements
    e. Maintainability and Support Requirements
    f. Security Requirements
    g. Business Continuity
    h. Disaster Recovery
    i. Regulatory Requirements
    j. Legal Requirements
4. Interface Requirements
    a. Software Interfaces
    b. Hardware Interfaces
    c. Communication Interfaces
5. Data Model Requirements
6. Middleware Requirements
7. Appendix A: Preliminary Data Points List
8. Appendix B: Preliminary Data Model
9. Acronyms
10. Glossary
11. EPRI's IntelliGrid Framework which calls for the development of use cases. Developing use cases includes the description the functions to be performed, a description of what occurs when, why, how, and under what conditions. It also describes the actors (systems, organizations, devices and users) performing the roles. Further function analysis and

steps in this analysis are described in detail to understand the system needs in all conditions. A use case template along with a large sampling of developed use case analyses, many tailored to electricity storage, are available at: http://www.smartgrid.epri.com/Repository/Repository.aspx

Energy storage vendors should provide the use case communication as part of the procurement package.

C.5 Sample Data Acquisition System Specification (Provided by PNM)

Requirements

Storage System
Data Acquisition & Management Project

1 Project Introduction

1.1 Opportunity Description

Describe project background, partners and overall data needs and data systems involved.

1.2 Business Need

Example: primary project has several requirements related to data which include: providing information to the storage system and other vendors for warranty purposes and providing information to other internal and external business partners for analysis.

The project will also provide access to hardware controls to specific partners subject to utility security requirements.

1.3 Justification

Describe the market driver for the storage system – what problem is being solved? e.g. The nature of large scale renewable resources creates a system risk from the intermittency of those renewable resources, as well as the fact that the output of resources such as PV do not align with the times of greatest energy demand and utilization. This project will demonstrate a potential solution that can help mitigate future risk on the utility's system, stemming from increased use of PV technology.

This project allows us to understand the impacts of large scale PV on the distribution system and investigate mitigation and economic enhancement strategies.

1.4 Project Objectives

- Meet the requirements of the primary project for data storage, data distribution and system access to internal and external stakeholders.

1.5 In Scope

- Retrieve and store data from __ data collection points at the battery / PV site. The data will be gathered at the required time intervals that will vary from one second to one minute.
- Develop and implement a data model to capture data being generated by the battery / PV site.
- Distribute selected data to ___ and other internal and external business partners for analysis.
- Provide required security to protect confidential/proprietary data including point to point basis.
- Address any security requirements necessary to protect the utility's computer network, electric distribution, and telecommunications systems.
- Security interoperability with UTILITY's Security standards & Cyber Security.
- Provide specifications and requirements to Communications Group so that they can provide sufficient bandwidth and physical infrastructure to support the data traffic.

1.6 Out of Scope

- Data requirements for other utility initiatives will not be met by this project.
- Physical security at the site will be provided by the primary project

1.7 System Context

C.1.1.1 **As-Is**

No current state exists.

C.1.1.2 **To-Be**

Include conceptual architectural diagram that details which actors (people, groups, devices) are to communicate and how they communicate (protocols and physical layers) with other actors

1.8 Stakeholders and Users

[Removed from vendor version]

1.9 Risks

[Removed from vendor version]

1.10 Assumptions

[Removed from vendor version]

1.11 Constraints

- Data transmission and storage needs to begin by ___.

2 Functional Requirements

2.1 System Functionality

	Requirement	Owner	Critical
2.1.1	The solution shall provide a method for **retrieving specific data** from solar and battery technology source systems that will be located at the storage site, which are itemized in the Interface Requirements section of this document. *Note: Refer to Points List in Appendix.*	UTILITY	x
2.1.2	The solution shall provide a method for **receiving specific data** from over __collection points from various devices located at the site.	UTILITY	x
2.1.3	The solution shall extract data from sources in regular **intervals** ranging from 1 second to every 60 seconds, depending upon stakeholder requirements.	UTILITY	x
2.1.4	The solution shall provide a method for **storing** acquired data from source systems at the site, for a period of time to be defined by the user.	UTILITY	x
2.1.5	The solution shall provide a method for **transmitting** data in 15 minute intervals (or less depending on stakeholder requirements) from a site database to an offsite storage and reporting database.	UTILITY	x
2.1.6	The solution shall provide a method for **storing** extracted data offsite for a minimum of __ years from the date of solution implementation.	UTILITY	x
2.1.7	The solution shall provide a method for **archiving** all stored data into a secondary storage location, at a user-selected time cycle such as every 30 days, quarterly, annually, etc.	UTILITY	x
2.1.8	The solution shall provide a method for **retrieving archived** data within 24 hours of the request for retrieval.	UTILITY	
2.1.9	The solution shall provide a method for setting varying **retention** schedules on specified datasets in both the production storage database and the archived storage database.	UTILITY	
2.1.10	The solution shall provide a method for users to retrieve, display, and otherwise **make available** all data stored in the production database, subject to authorized user permissions and UTILITY's Security Requirements.	UTILITY	x
2.1.11	The solution shall provide a method for transmitting or otherwise making data available to user-selected **internal** entities.	UTILITY	x
2.1.12	The solution shall provide a method for transmitting or otherwise making data available to user-selected **external** entities, in a manner	UTILITY	x

	that that is compliant with UTILITY's Security Requirements.		
2.1.13	The solution shall provide a method for **authorized vendors** and other external parties to **access** appropriate systems and resulting datasets, from a point outside the company's network (through a server in the DMZ), subject to UTILITY's Security Requirements.	UTILITY	x
2.1.14	The solution shall provide a method for authorized internal users to create, generate, and produce user-designed **reports** on demand (monthly, quarterly, annual, etc.) subject to UTILITY's Security Requirements.	UTILITY	X
2.1.15	The solution shall perform **time synchronization** functions on all data reads from the devices at the server level and time stamps at the device or gateway level.	UTILITY	
2.1.16	The solution shall be capable of **grouping and segregating** stored records by specific data fields and record characteristics including, but not limited to, the following categories as applicable to the source device: • Operational vs. analytical • Operational vs. financial • Public vs. private • Vendor proprietary and confidential • Identify which data columns are available to user-selected internal and external entities. • Baseline vs. actual achieved operation (for purposes of economics and costing).	UTILITY	x
2.1.17	The solution shall be capable of allowing users to **select and query** data by specific fields and record characteristics including, but not limited to, the following categories as applicable to the specific data type: • Date/time ranges of all data reads. • Test modes in operation at time of read. • PV and Battery configuration settings at time of read. • Weather conditions at time of read.	UTILITY	x
2.1.18	The solution shall provide a method for **transforming** all collected data from the various source devices into a **uniform** format, which will be transferred to a common database.	UTILITY IT	x
2.1.19	The solution shall perform **evaluation** on data for "changed-data-only" transaction comparison, prior to committing to the database	UTILITY	
2.1.20	The solution's data acquisition system shall identify and appropriately **label null values** of data which are non-existent points of data (e.g., system outage or no reading taken), as opposed to extrapolated data within each record based on no change from previous data read.	UTILITY	x

2.1.21	The solution shall identify and appropriately label each data field within the record as being evaluated and deemed and "**accurate read**," as defined by each device.	UTILITY	x
2.1.22	The solution shall include a **date and time stamp at the gateway or device level** on every record reading, regardless of record type.	UTILITY	x
2.1.23	The solution shall capture, store and forward **numerical data types** without any display formatting, such as commas.	UTILITY	
2.1.24	The solution's data acquisition system shall capture, store, and forward the **status** of all devices at the time of read.	UTILITY	x
2.1.25	The solution's data acquisition system shall provide the ability to **translate status** of all devices, in order to create a uniform definition of status across devices.	UTILITY	x
2.1.26	The solution's data acquisition system shall capture, store, and forward any **alarm** details that may have been recorded on the device at the time of read.	UTILITY	x
2.1.27	The solution's data acquisition system shall capture, store, and forward the **configuration settings** in place on all devices at the time of read.	UTILITY	x
2.1.28	The solution's data acquisition system shall provide the ability to **map** data accurately from each device into a common database onsite for initial storage and eventual forwarding.	UTILITY	x
2.1.29	The solution's data acquisition system shall capture, store, and forward the **settings of the feeder** at the time of read.	UTILITY	x
2.1.30	The solution data acquisition system shall collect, store, and forward all records at the individual **record level**.	UTILITY	x
2.1.31	The solution's data acquisition system shall be capable of storing and forwarding ***physical*** changes at the site, which may have affected performance readings and were not otherwise captured electronically through the devices, such as climate control changes and cleaning of dust off PV panels.	UTILITY	x
2.1.32	The solution must be capable of linking or providing datasets to the ______ information Clearinghouse.	DOE	x

3 Non-Functional Requirements

3.1 Look & Feel Requirements

	Requirement	Owner	Critical
3.1.1	The solution must be capable of displaying the company's approved **logo** on selected reports.	UTILITY	
3.1.2	The solution must be capable of displaying a **confidentiality** statement on selected reports, queries, and any other output formats.	UTILITY	

3.2 Usability Requirements

	Requirement	Owner	Critical
3.2.1	The solution shall include a **data dictionary**, listing all data fields and their associated definitions, to be made available to the business in a readable format such as Acrobat pdf.	UTILITY	
3.2.2	The solution for data acquisition and transmitting shall be **accessible** at the **physical** site, subject to UTILITY's Security Requirements.	UTILITY	x

3.3 Performance Requirements

	Requirement	Owner	Critical
3.3.1	The solution shall be capable of extracting, transmitting, and storing an estimated __ **million records per day** from pre-identified collection points. *Estimated calculations*: 60 seconds * 60 minutes = 3600 seconds in one hour 3,600 seconds * 24 hours = 86,400 seconds in 24 hours 85,400 seconds * ___ sites = _____ records per day.	UTILITY	X
3.3.2	The solution shall be capable of retrieving, storing and forwarding an estimated 100 byte record length, including all measurements and settings. **Assumptions** Record Length = __ bytes Number of data collection points = __ Reads per minute = __	UTILITY	x

3.3.3	The solution shall be capable of handling the following site data volumes and velocities, based on the assumptions listed in Requirement 3.3.2. **Volumes & Velocities** Records per second = ____ Bytes per second = ____ Records per 15 minutes = ____ Records per hour = ______ MBytes per 15 minutes = ___ MBytes per hour = ___ Hours per day operation = ___ MBytes per day = ____	UTILITY	x
3.3.4	The solution shall be capable of storing and managing data at the following estimated volumes, based on the assumptions listed in Requirement 3.3.2. **Anticipated Storage Volumes** Gbytes Per month(raw data) = ________ Gbytes per year (raw data) = ________ Est DB storage per month (GB) = ________ Est DB Storage per year (GB) = ________	UTILITY	x

3.4 Operational Requirements

	Requirement	Owner	Critical
3.4.1	If the solution selected requires an ____ **platform**, the solution shall be compatible with ______(appropriate current version)	IT	x
3.4.2	If the solution selected requires a ______**Server**, the solution shall be compatible ______(appropriate current version)	IT	x
3.4.3	If the solution selected requires a ______ **Operating System,** the solution shall be compatible ______(appropriate current version)	IT	x
3.4.4	If the solution selected can operate within a virtualized server environment, the solution shall be compatible with ______ (appropriate current version)**.**	IT	
3.4.5	If the solution selected requires an internet platform, the solution shall be compatible with ______(appropriate current version)	IT	
3.4.6	The solution shall be compatible with __________ reporting and analytics tool.	UTILITY	

3.5 Maintainability and Support Requirements

	Requirement	Owner	Critical
3.5.1	The solution's **storage/reporting and archival databases** shall be located at UTILITY's _____Center in ___(location).	IT	
3.5.2	The solution's **application server** shall be located at UTILITY's _____Center in ___(location)..	IT	
3.5.3	The solution's **database** located at the **site** shall be supported by ______.	UTILITY	
3.5.4	The solution shall provide a method for **error handling** and/or logging for the data handling process from start to finish (from data reads at the site to transmission to external entities)	UTILITY & IT	x
3.5.5	The solution shall be subject to, and comply with, the ________process for all system and object changes before being migrated to a production server.	IT	x

3.6 Security Requirements

	Requirement	Owner	Critical
3.6.1	Specific and detailed security requirements are listed here based on Utility communication systems & networks security policies and standards. A robust version lists all company IT security requirements	IT Security	x

3.7 Business Continuity

	Requirement	Owner	Critical
3.7.1	The solution shall be **available** to authorized users 24 hours a day, 7 days a week, with unscheduled down time no greater than two consecutive calendar weeks at one time.	UTILITY	
3.7.2	The solution's data acquisition **routines** are expected to complete successfully at the stated intervals in the Preliminary Data Points list provided in Appendix A.	UTILITY	

3.8 Disaster Recovery

	Requirement	Owner	Critical
3.8.1	The solution's online storage database shall be **backed up** to secondary media on a routine schedule, at a minimum of every 24 hours, every day of the calendar week.	UTILITY	

3.9 Regulatory Requirements

More information about NERC CIP requirements can be found on their website: http://www.nerc.com/page.php?cid=2|20

	Requirement	Owner	Critical
3.9.1	All cyber assets for the solution and systems contained within must be **evaluated** for NERC CIP applicability during the design phase.	IT Security	X
3.9.2	**Assets identified** as in-scope for NERC CIP compliance must meet the NERC CIP-002 through CIP-009 requirements applicable to the asset, prior to implementation.	IT Security	X
3.9.3	The system shall not have the capability to impede, interfere with, or degrade, any existing UTILITY solution(s) in place.	IT Security	X

3.10 Legal Requirements

None defined.

	Requirement	Owner	Critical

4 Interface Requirements

4.1 Software Interfaces

	Requirement	Owner	Critical
4.1.1	The solution shall be capable of extracting data from Storage System, which will be used for monitoring the performance, and reading/producing all pertinent data to the storage system, as well as allowing settings control.	UTILITY	x

4.2 Hardware Interfaces

	Requirement	Owner	Critical
4.2.1	The solution must interface with **source devices** that will produce readings that will be interrogated for data acquisition. Source devices include, but may not be limited to: • UTILITY Metering • PCS Controller • Other Sensors • Meteorological stations (wind, temp, etc.)	UTILITY	x

4.3 Communication Interfaces

	Requirement	Owner	Critical
4.3.1	The solution shall include a _______ protocol interface in the solution, which will interface with various source devices at the site.	UTILITY	x
4.3.2	The solution shall **interrogate** source devices at specified internals listed in the Preliminary Data Points document in Appendix, capturing and storing data in one database at the physical site.	UTILITY	x
4.3.3	The solution shall transfer data from the physical site database to ________(location), using ____**(network description)**	UTILITY	x
4.3.4	The solution's communication lines shall be capable of handling a minimum of ______ of transmission per hour.	STORAGE MFTR	x
4.3.5	The storage system utilizes ______ for maintenance and must be supported.	STORAGE MFTR	X
4.3.6	The storage system utilizes ______ for data logging, and must be supported.	STORAGE MFTR	X

5 Data Model Requirements

	Requirement	Owner	Critical
5.1.1	The solution's data model shall include calculated fields that contain common data **aggregation** summations, as they apply to specific data types.	UTILITY	
5.1.2	The solution's data model shall allow for **null values** in any record field except for date and time of data reading.	UTILITY	X
5.1.3	The solution's data model shall be **minimally normalized**.	UTILITY	x
5.1.4	The solution's data model shall provide a method for storing **information** about each data field, their descriptions, and typical purpose.	UTILITY	

6 Middleware Requirements

None defined.

	Requirement	Owner	Critical
6.1.1			

7 Appendix A: Preliminary Data Points List

8 Appendix B: Preliminary Data Model

9 Acronyms

10 Glossary

APPENDIX D: UTILITY AND OWNER INTERCONNECTION COSTS AND SCHEMATICS FOR VARIOUS STORAGE SYSTEMS

Appendix D: Table of Contents

Appendix D: List of Figures

Appendix D: List of Tables

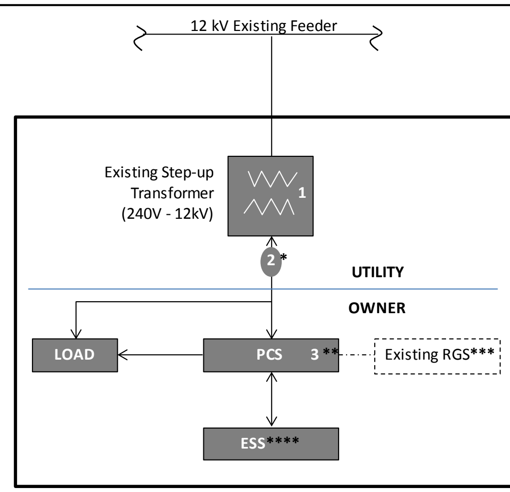
(none)

UTILITY AND OWNER INTERCONNECTION COSTS AND SCHEMATICS FOR VARIOUS STORAGE SYSTEMS

D.1 5-kW TO 100-kW Storage System Utility and Owner Interconnection and Equipment Costs

The following schematics represent interconnection configurations for various sizes of electricity storage systems illustrating the utility and owner interconnection equipment, such as transformers and switchgear that is required for that particular type and size of storage system.

The costs for the equipment are representative costs only and these can be changed if more specific costs are available for that site or if additional equipment is necessary. The costs estimated in these schematics have been used to derive the total system costs shown in the plots in *Chapter 2: Electricity Storage Technologies: Cost, Performance, and Maturity* and in the detailed cost breakdowns.



Utility Interconnection (UI) Costs

		5kW	15kW	25kW	50kW	100kw
1	Step-up	Existing	Existing	Existing	Existing	Existing
2	Smart Metering:	$500	$500	$500	$500	$500
	Equipment	incl.	incl.	incl.	incl.	incl.
	Subtotal	**$500**	**$500**	**$500**	**$500**	**$500**
	$/kW	$100	$33	$20	$10	$5

Owner Interconnection (OI) Costs

		5kW	15kW	25kW	50kW	100kw
3	PCS Equipment:	$9,500	$24,500	$31,000	$44,500	$79,000
	PCS Installation:	$5,000	$12,500	$15,500	$22,500	$39,500
	Subtotal	**$14,500**	**$37,000**	**$46,500**	**$67,000**	**$118,500**
	$/kW	$2,900	$2,467	$1,860	$1,340	$1,185
	Total (UI and OI)	**$15,000**	**$37,500**	**$47,000**	**$67,500**	**$119,000**
	$/kW	$3,000	$2,500	$1,880	$1,350	$1,190

System Inverter Scope (kW)

	5kW	15kW	25kW	50kW	100kw
Size (LxWxH):	74"x45" x26.875"	74"x45" x26.875"	74"x45" x26.875"	74"x45" x26.875"	67"x86" x23"
Outdoor Enclosure	y	y	y	y	y
Weight:	1732 lbs	1732 lbs	1732 lbs	1732 lbs	2605 lbs
Efficiency:	96	96	96	96	98

NOTES:
* Supplier to provide metering connections at 240V
** UL 1741 Listed
*** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required. This assumes that the DC voltage output for the ESS is similar to the RGS.
**** Battery Capacity does not exceed peak load. Therefore existing transformer does not need upgrades
PCS Power Conditioning System

Figure D-1. Schematic of 5 to 10 kW Storage System showing Utility and Owner Interconnection and Equipment Costs

D.2 250-kW, 500-kW, and 1-MW Storage System Utility and Owner Interconnection and Equipment Costs

Utility Interconnection (UI) Costs

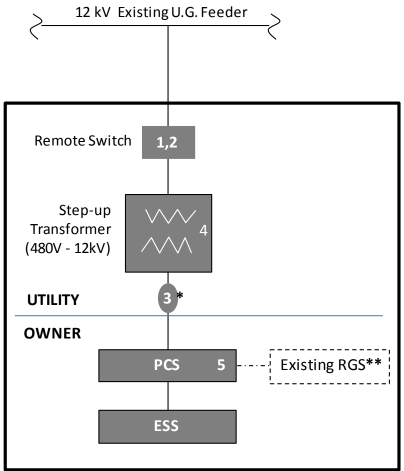
		250kW	500kW	1MW
1	*** Remote Switch:	$100,000	$100,000	$100,000
2	Communication (Radio):	Incl.	Incl.	Incl.
3	Smart Metering:	$800	$800	$800
4	Transformer Equipment:	$12,500	$20,000	$30,000
	Transformer Installation:	$12,500	$20,000	$30,000
	Subtotal	**$125,800**	**$140,800**	**$160,800**
	$/kW	$503	$282	$161

Owner Interconnection (OI) Costs

		250kW	500kW	1MW
5	PCS Equipment:	$131,500	$233,500	$367,000
	PCS Installation:	$33,000	$58,500	$92,000
	Subtotal	**$164,500**	**$292,000**	**$459,000**
	$/kW	$658	$584	$459
	Total (UI and OI) Cost	**$290,300**	**$432,800**	**$619,800**
	$/kW	$1,161	$866	$620

System Inverter Scope (kW)

	250kW	500kW	1MW
Size (LxWxH):	22'x8'5" x8'7"	83"x159" x31"	83"x115" x38"
Outdoor Enclosure Y or N:	y	y	y
Weight:	28000.00	7700.00	4500.00
Efficiency:	97	97	97



NOTES:

* Supplier to provide metering connections at 480V

** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required.This assumes that the DC voltage output for the ESS is similar to the RGS.

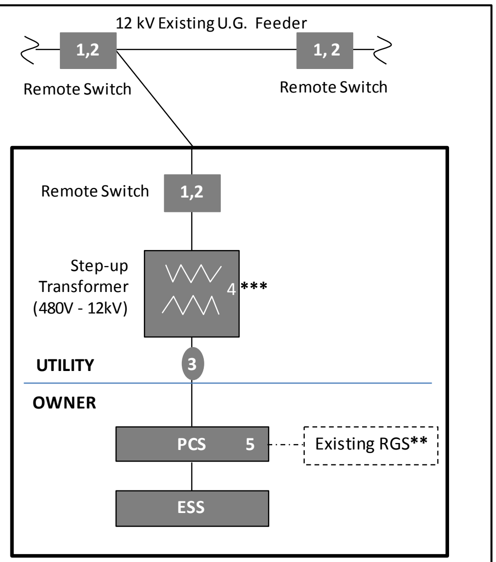
*** U.G. Distribution System with Pad Mounted Equipment

PCS Power Conditioning System

U.G. UnderGround

Figure D-2. Schematic of 250-kW, 500-W, and 1-MW Storage System showing Utility and Owner Interconnection and Equipment Costs

D.3 2-MW, 2.5-MW, and 3-MW Storage System Utility and Owner Interconnection and Equipment Costs



Utility Interconnection (UI) Costs

#		2MW	2.5MW	3MW
1	**** Remote Switches:	$300,000	$300,000	$300,000
2	* Communication :	incl.	incl.	incl.
3	Metering:	$800	$800	$800
4	Transformer Equipment :	$60,000	$70,000	$90,000
	Transformer Installation:	$60,000	$70,000	$90,000
	Subtotal	**$420,800**	**$440,800**	**$480,800**
	$/kW	$210	$176	$160

Owner Interconnection (OI) Costs

#		2MW	2.5MW	3MW
5	PCS Equipment:	$523,000	$642,500	$749,500
	PCS Installation:	$131,000	$160,500	$187,500
	Subtotal	**$654,000**	**$803,000**	**$937,000**
	$/kW	$327	$321	$312
	Total (UI and OI) Cost	**$1,074,800**	**$1,243,800**	**$1,417,800**
	$/kW	**$537**	**$498**	**$473**

System Inverter Scope (kW)

	2MW	2.5MW	3MW
Size (nos.xLxWxH):	2 x 22'x8'5" x8'7"	2 x 22'x8'5" x8'7"	2 x 22'x8'5" x8'7"
Outdoor Enclosure Y or N:	y	y	y
Weight:	2 x 28000	2 x 28000	2 x 28000
Efficiency:	97	97	97

NOTES:

* Assumes fiber optic but will vary with utility requirements (i.e., radio)

** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required.This assumes that the DC voltage output for the ESS is similar to the RGS.

*** 2X1.25MVA Step-up Transformers (480V - 12kV)

**** U.G. Distribution System with Pad Mounted Equipment

PCS Power Conditioning System

U.G. UnderGround

Figure D-3. Schematic of 2-MW, 2.5 MW, and 3-MW Storage Systems showing Utility and Owner Interconnection and Equipment Costs

D.4 5-MW Storage System Utility and Owner Interconnection and Equipment Costs

Utility Interconnection (UI) Costs

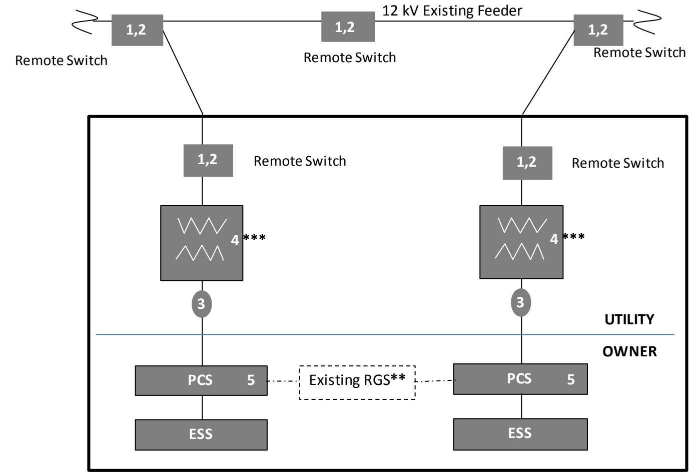
1	**** Remote Switches:	$500,000		
2	* Communication :	Incl		
3	Metering:	$800		
4	Transformer Equipment :	$140,000		
	Transformer Installation:	$140,000		
	Subtotal	**$780,800**	$/kW	$156

Owner Interconnection (OI) Costs

5	PCS Equipment:	$1,217,500		
	PCS Installation:	$304,500		
	Subtotal	**$1,522,000**	$/kW	$304
	Total (UI and OI) Cost	**$2,302,800**	**$/kW**	**$461**

System Inverter Scope (kW)

Size (nos.xLxWxH):	4 x 22'x8'5" x8'7"
Outdoor Enclosure Y or N:	y
Weight:	4 x 28000
Efficiency:	97



NOTES:

* Assumes fiber optic but will vary with utility requirements (i.e., radio)

** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required.This assumes that the DC voltage output for the ESS is similar to the RGS.

*** 2X1.25MVA Step-up Transformers (480V - 12kV)

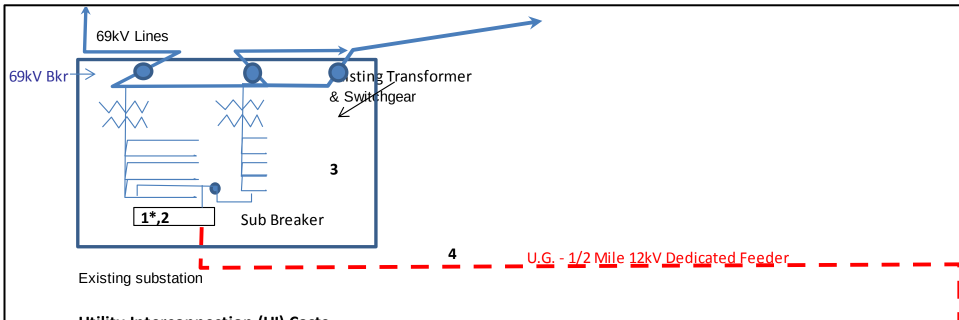
**** U.G. Distribution System with Pad Mounted Equipment

PCS Power Conditioning System

U.G. UnderGround

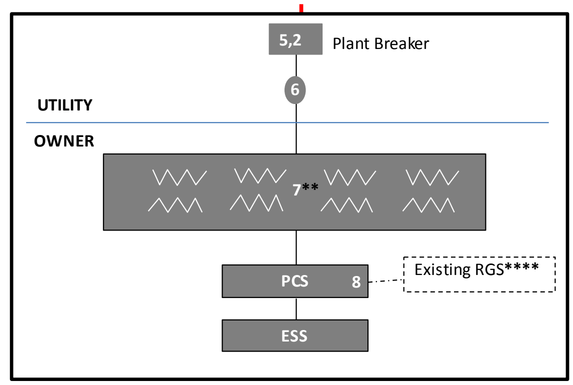
Figure D-4. Schematic of 5-MW Storage System showing Utility and Owner Interconnection and Equipment Costs

D.5 10-MW Storage System Utility and Owner Interconnection and Equipment Costs



Utility Interconnection (UI) Costs

1	Substation Breaker	$200,000		
2	***Communicatio	$40,000		
3	Dedicated	$600,000		
4	12kV Dedicated	$250,000		
5	Plant Breaker:	$200,000		
6	Metering:	$100,000		
	Subtotal	**$1,390,000**	$/kW	$139



Owner Interconnection (OI) Costs

7	Transformer	$280,000		
8	PCS Equipment:	$2,288,500		
	Transformer	$280,000		
	PCS Installation:	$572,000		
	Subtotal	**$3,420,500**	$/kW	$342
	Total (UI and OI) Cost	**$4,810,500**	**$/kW**	**$481**

System Inverter Scope (kW)

	4 x
Size (nos.xLxWxH):	22'x8'5"x8'7"
Outdoor Enclosure	y
Weight:	4 x 28000
Efficiency:	97

NOTES:

* Assumes breaker is available

** 2X1.25MVA Step-up Transformers (480V - 12kV)

*** Assumes fiber optic placement with UG feeder construction

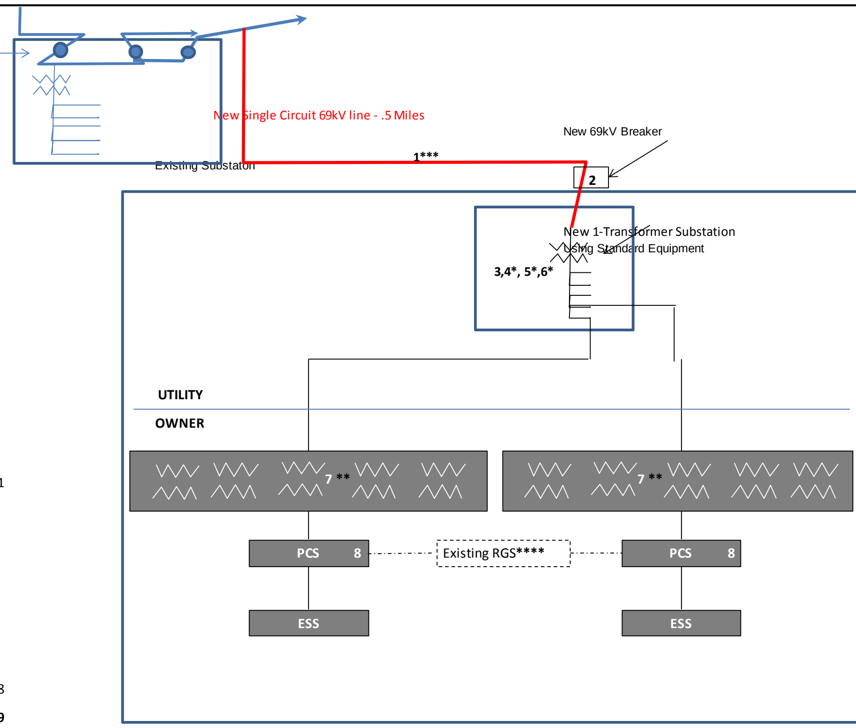
**** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required. This assumes that the DC voltage output for the ESS is similar to the RGS.

PCS Power Conditioning System

U.G. UnderGround

Figure D-5. Schematic of 10-MW Storage System showing Utility and Owner Interconnection and Equipment Costs

D.6 25-MW Storage System Utility and Owner Interconnection and Equipment Costs



Utility Interconnection (UI) Costs

1	***69kV Feeder	$400,000		
2	Line Breakers w/	$625,000		
3	Onsite Substation	$3,000,000		
4	*Plant Breaker:	included		
5	* Communication:	included		
6	* Metering:	included		
	Subtotal	**$4,025,000**	$/kW	$161

Owner Interconnection (OI) Costs

7	Transformer	$700,000		
8	PCS Equipment:	$5,154,500		
	Transformer	$700,000		
	PCS Installation:	$644,500		
	Subtotal	**$7,199,000**	$/kW	$288
	Total (UI and OI) Cost	**$11,224,000**	**$/kW**	**$449**

System Inverter Scope (kW)

	20 x
Size (nos.xLxWxH):	22'x8'5"x8'7"
Outdoor Enclosure	y
Weight:	20 x 28000
Efficiency:	97

NOTES:

* Included in new onsite substation

** 2X1.25MVA Step-up Transformers (480V - 12kV)

*** Cost includes new circuit plus easement

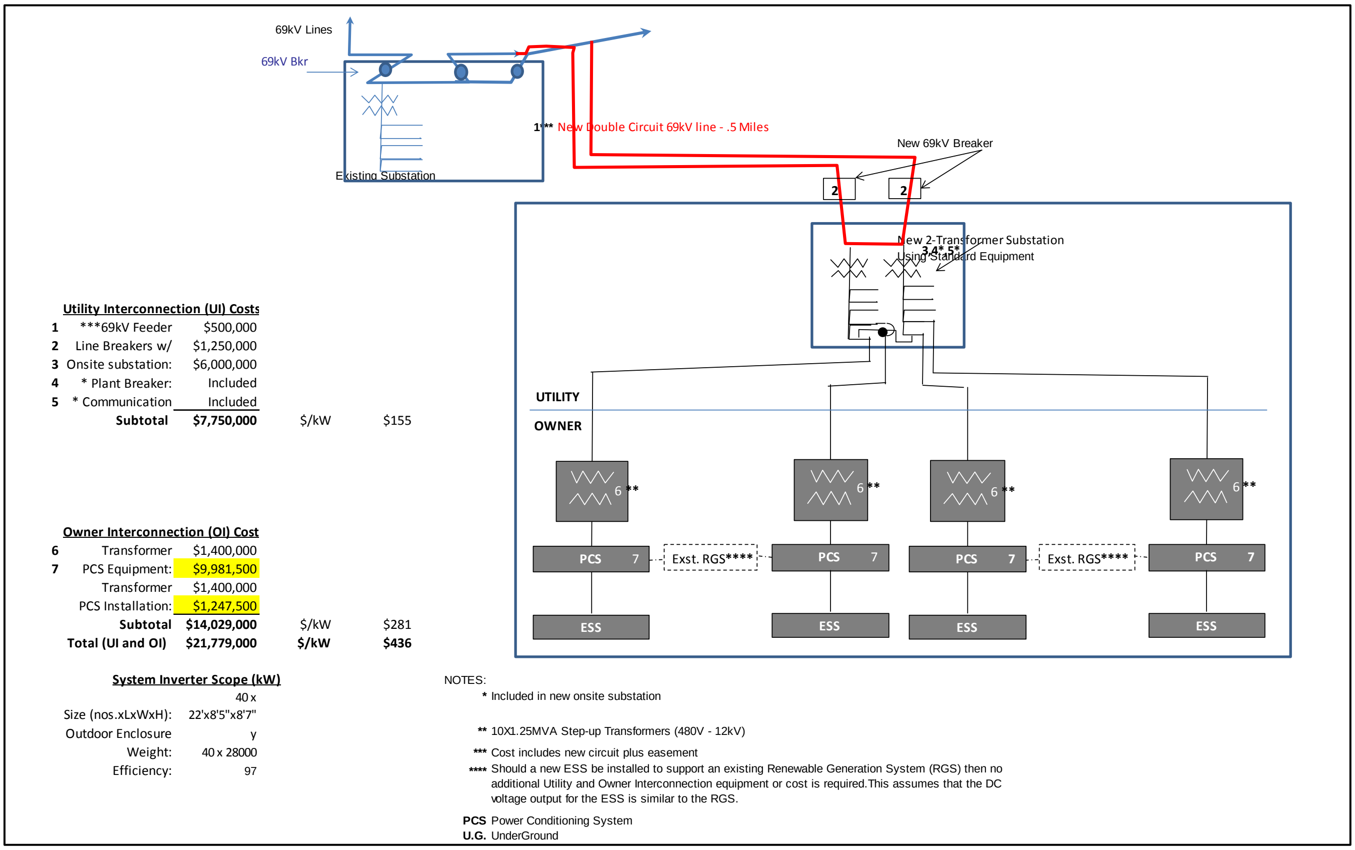
**** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required.This assumes that the DC voltage output for the ESS is similar to the RGS.

PCS Power Conditioning System

U.G. UnderGround

Figure D-6. Schematic of 25-MW Storage System showing Utility and Owner Interconnection and Equipment Costs

D.7 50-MW Storage System Utility and Owner Interconnection and Equipment Costs



Utility Interconnection (UI) Costs

1	***69kV Feeder	$500,000		
2	Line Breakers w/	$1,250,000		
3	Onsite substation:	$6,000,000		
4	* Plant Breaker:	Included		
5	* Communication	Included		
	Subtotal	**$7,750,000**	$/kW	$155

Owner Interconnection (OI) Cost

6	Transformer	$1,400,000		
7	PCS Equipment:	$9,981,500		
	Transformer	$1,400,000		
	PCS Installation:	$1,247,500		
	Subtotal	**$14,029,000**	$/kW	$281
	Total (UI and OI)	**$21,779,000**	**$/kW**	**$436**

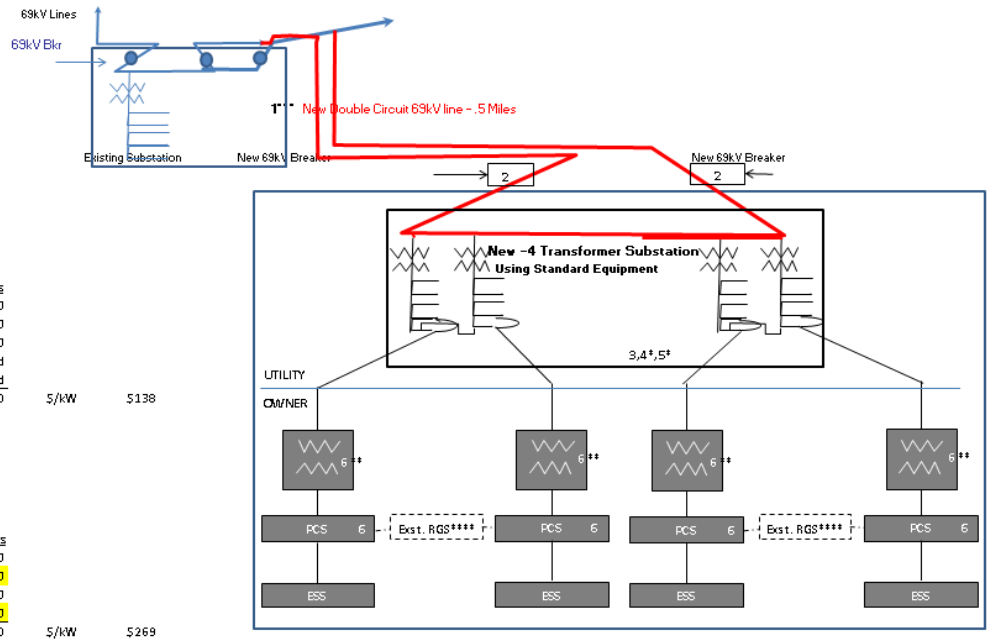
System Inverter Scope (kW)

	40 x
Size (nos.xLxWxH):	22'x8'5"x8'7"
Outdoor Enclosure	y
Weight:	40 x 28000
Efficiency:	97

NOTES:
* Included in new onsite substation
** 10X1.25MVA Step-up Transformers (480V - 12kV)
*** Cost includes new circuit plus easement
**** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required.This assumes that the DC voltage output for the ESS is similar to the RGS.
PCS Power Conditioning System
U.G. UnderGround

Figure D-7. Schematic of 50-MW Storage System showing Utility and Owner Interconnection and Equipment Costs

D.8 100-MW Storage System Utility and Owner Interconnection and Equipment Costs



	Utility Interconnection (UI) Costs			
1	***69kV Feeder	$500,000		
2	:ers w/Protection:	$1,250,000		
3	Onsite	$12,000,000		
4	* Plant Breaker:	Included		
5	* Communication:	Included		
	Subtotal	$13,750,000	$/kW	$138

	Owner Interconnection (OI) Costs			
6	Transformer	$2,800,000		
7	PCS Equipment:	$18,893,500		
	Transformer	$2,800,000		
	PCS Installation:	$2,361,500		
	Subtotal	$26,855,000	$/kW	$269
	Total (UI and OI)	$40,605,000	$/kW	$406

System Inverter Scope (kW)	
Size (nos.xLxWxH):	80 x 22'x8'5"x8'7"
Outdoor	y
Weight:	80 x 28000
Efficiency:	97

NOTES:

* Included in new onsite substation
** 20X1.25MVA Step-up Transformers (480V - 12kV)

*** Cost includes new circuit plus easement
**** Should a new ESS be installed to support an existing Renewable Generation System (RGS) then no additional Utility and Owner Interconnection equipment or cost is required.This assumes that the DC voltage output for the ESS is similar to the RGS.

PCS Power Conditioning System
U.G. UnderGround

Figure D-8. Schematic of 100 MW Storage System showing Utility and Owner Interconnection and Equipment Costs

APPENDIX E: REGULATIONS

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(none)

REGULATIONS

E.1 Non-Storage Regulatory Proceedings Affecting Electricity Storage Opportunities

Although many state energy offices and PUCs are aware of the general benefits of energy storage, many do not currently have any rulemaking proceedings specifically to encourage the use of electricity storage. Absence of such a proceeding does not mean that opportunities may not exist elsewhere and there could be other proceedings that may be appropriate and possibly important venues for promoting energy storage services. California's regulatory scene is a good example: both storage and non-storage proceedings create opportunities for electricity storage deployment.

In the recent past advocates of the storage industry have used the non-storage proceedings to achieve two goals: first, to develop detailed and nuanced understanding of electrical system operations (e.g., load following) that has traditionally sought only conventional generation options and second, to educate regulators about capabilities, uses, and limitations of storage technologies and identify rules that may inadvertently inhibit energy storage participation.

E.2 References for Details and Updates on Regulatory Proceedings

The regulatory regime at the national and state levels affecting opportunities and pricing for electricity storage systems and services is evolving continuously. Those who want to design their products and services to serve the electrical grid must remain informed of industry developments, a labor-intensive and daunting task. However, there are tools that can help. One option to remain informed is through websites that continuously update regulations and interpret their impact on the industry. Industry associations' websites are good locations for such an update. Another option is a database funded by the DOE for policy updates.[1] Lastly, a separate handbook[2] funded by the DOE and published by SNL has a chapter that reviews the current and recent PUC dockets on electricity storage.

To aid the reader in keeping up with the evolving developments in the regulatory sphere, citations to and brief discussions of the current status of the formal regulatory investigations presently under review in various jurisdictions around the United States are discussed below.

E.3 Synopsis of Investment Recovery Requests

This section provides a review of investment recovery cases, or project approval cases, in which regulated utilities have filed requests related to electricity storage technology investments with public hearings held before state PUCs around the United States. This is not a comprehensive review, in that the cases selected are only those that have had procedural debate on electricity storage proposals. Other cases with storage system proposals exist but without any procedural debate addressing electricity storage. This review presents and discusses the issues raised by

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[1] https://www.energystorageexchange.org, last accessed April 29, 2013.

[2] *Evaluating Utility Procured Electric Energy Storage Resources: A Perspective for State Electric Utility Regulators,* Bhatnagar, Dhruv and Loose, Verne, SAND2012-9422, Sandia National laboratories, Albuquerque, NM; November 2012.

PUCs, regulated utilities, storage owners, and other interested parties (or interveners) on the electricity storage system proposals and the challenges these issues present to storage system deployment.

E.3.1 Synopsis Requests for Investment Recovery Through Rate-Base Addition

The investment recovery cases summarized below are presented by state. Many of these cases were 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 San Diego Gas and Electric (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 in 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 (TCOS) recovery for the installation of a Sodium-sulfur (NaS) Battery System (4.8 MW) in Presidio, TX. The purpose of the system is to ensure the reliability of electricity in a 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*
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 and Electric*
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 and Electric*
Summary: A request for Commission approval to provide the balance of matching funds to support a federal grant of $24.9 million from the DOE for a Smart Grid 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 Energy Storage Project (TSP) *as part of California's Smart Grid Rule Making Process (*CAPUC, 2008)
Applicant: *Southern California Edison*
Summary: Southern California Edison Company (SCE) requested approval to recover up to $25,978,264 for SCE's cost share in the TSP. This cost share will be matched by $24,978,264 in Federal stimulus funding awarded by the DOE under ARRA. The project is a lithium-ion battery (8 MW/32MWh).
Case Status: *Approved:* July 2010
Project Status: *Projected to be in operation in late 2013.*

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 and Light Company*
Summary: Jersey Central Power and Light Company (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

E.3.2 Synopsis of Hearing Record Discussion on the Definition of Electricity Storage

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

In the AB2514 Rulemaking hearing, the need to define electricity 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 "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 electricity 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 Texas Industrial Energy Consumers (TIEC) and PUC staff, highlighted the lack of an operational definition of electricity storage, with differing operational classifications for the resource based on their differing perspectives. Arguments were made by the TIEC that electricity storage acts as generation because it delivers electricity to the grid. Thus, it would not be eligible for recovery under the utility's TCOS 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, 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 delineated. In this case, the Texas PUC had not determined the operational definition and goals for electricity storage in the Texas electric grid. This issue arose as a major discussion point in the case and may reflect the fact that electricity 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 and the rates for transmission and wholesale power are under the jurisdiction of the PUC.[3]

Due to a lack of determination about the use of electricity storage systems going forward, the Texas PUC made a decision based on the specific intended use of the battery system and was careful to state that the decision would not set a precedent for future cases. Because 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).

[3] ERCOT, the Texas electric grid, is connected to the rest of the United States only at a few points at the borders and the Texas grid is thus an intrastate network. Because it operates as an independent grid, its transmission service and wholesale power rates are free from FERC regulation and fall only 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.

E.4 The Regulatory Environment for Energy Storage

The present state of the regulated utility environment for electricity storage system deployment was discussed to provide state utility regulators an understanding of how electricity storage systems can be considered an electric grid asset.

Much of the literature about electricity 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. The one feature that makes these systems unique—their ability to store electricity — 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 increase deployment have to do with economic comparisons—can electricity storage systems deliver their services at lower cost than competing technologies? Regulators 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 electricity 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 electricity 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 electricity storage technologies. The following are among the most important take-aways from this analysis:

- Electric Energy Storage (EES) systems 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 electricity;
- Vertically integrated utilities may have an advantage in their ability to internalize all of the benefits available from electricity 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, may help increase deployment by aiding utilities in proposing, and regulatory commissions in evaluating, energy storage systems; and
- Phase-in tariffs or other incentives might provide the necessary financial incentives to induce utilities to invest in ESS in the absence of carbon pricing.

E.5 Regulatory Database[4]

The DOE has initiated an Internet-based, interactive compendium of electricity storage projects and policies. The effort is relatively recent, but, it has already become a credible repository of structured information on projects that can be sorted by location, technology type, size, ownership, and current status. The process of obtaining and maintaining the database is on-going, and new information is being added to the database regularly. Figure E-1 shows a sample screen from the website.

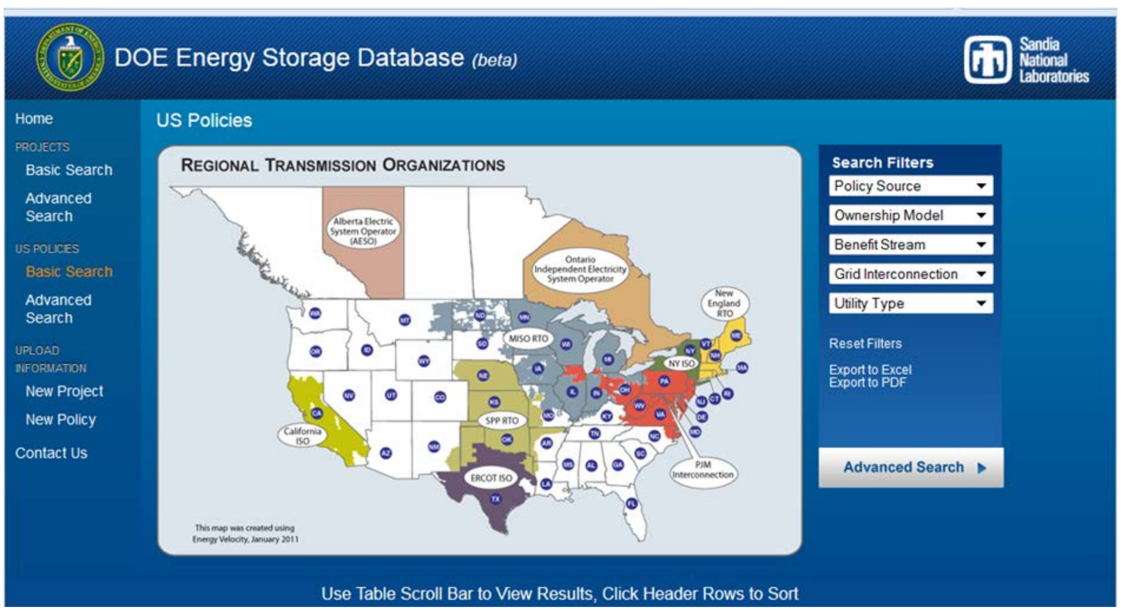

Figure E-1. The DOE International Energy Storage Database

4 The DOE International Energy Storage Database, http://www.energystorageexchange.org/policies, last accessed April 28, 2013.

APPENDIX F: TEST FACILITIES

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(none)

TEST FACILITIES

This appendix describes four test facilities in the U.S. that were operational in 2013 where storage systems can be tested for a variety of grid services. These four facilities were operational in 2013. There are other test facilities that are operated by storage system developers and vendors for their own needs and these are generally not available for use by others. Such test facilities are not included in this appendix.

F.1 DOE/SNL Energy Storage Test Pad and Energy Storage Analysis Laboratory

Commissioned in April 2011, the Energy Storage Test Pad (ESTP) provides trusted third-party testing and validation from the cell level to 1-MW ac electrical energy storage systems. The ESTP can test for both power and energy applications and offers a variety of services including energy time-shift, capacity, load-following, area regulation, voltage support, T&D deferral, demand charge management, and power quality and reliability. The test durations can range from one day to multiple months.

The ESTP can test a maximum capacity of 1-MW, 480 Vac 3-phase systems in grid-connected or stand-alone configuration using resistive and asynchronous loads with extensive data-logging capability. Along with SNL's Energy Storage Analysis Laboratory (ESAL), which tests from cell to module systems, these facilities provide users a venue for testing and validation of energy storage systems. Using a direct grid connection or simulated charge protocol along with detailed diagnostics and analysis, SNL can provide verification of a devices' reliability. In addition to providing testing and validation, system performance analysis, and development of new testing procedures, the ESTP and ESAL provide pre-certification, pre-installation, and verification of electrical energy storage systems.

The ESTP and ESAL are capable of testing energy storage devices to manufacturer's specification using characterization and application-specific cycle testing. These capabilities, supported by SNL's electrochemistry and material sciences experience provide a great depth in fundamental testing at the cell and module level.

The full range of ESTP and ESAL features are summarized in Figure F-1 and Figure F-2. The enclosure in the middle houses the programmable load banks and miscellaneous switchgear, and data-acquisition hardware in housed in the enclosures in the background.

The PV array partially visible in the background of Figure F-3 is part of SNL's Distributed Energy Technologies Laboratory (DETL). The DETL has a large portfolio of distributed and renewable generation technologies, including the 160-kW PV array, micro-turbine, diesel engine, an additional 750 kWh of battery storage, and several types of loads. These resources are interconnected on a 480-V bus to test various microgrid configurations. The ESTP, which can interconnect to the DETL to use the full capabilities of the DETL microgrid, provides the ability to test the storage systems under an even wider range of operating conditions.

For additional information regarding ESTP testing of a storage system: http://www.sandia.gov/ess/bus_test.html.

Energy Storage Test Pad (ESTP) Overview

System Capacity/Capability

- 1.5 MVA, 12470 V to 480 VAC 3-phase transformer capable of testing up to 1 MW energy storage systems.
- 2500 amp switchboard with motor operated main breaker.
- Five feeder breakers capable of a 1600 amp single point of EES connection or multiple feed connections through a 1200 amp branch panel.
- 1 MW/1 MVAR loadbank.
- Subcycle metering feeder breakers for transient analysis.

Testing Capability

- Can test for both power and energy applications including energy time shift, capacity, load following, area regulation, voltage support, T&D deferral, demand charge management, and power quality and reliability.
- Test duration can range from one day to multiple months.
- Scalable from 5 KW to 1 MW, 480 VAC, 3 phase.

Data Monitoring

- All breakers are equipped with subcycle wave capture meters.
- Can capture voltage, current, KVA, KW, KVAR, PF, frequency, harmonics and transients.
- Provides fiber optic or Ethernet connectivity to monitor parameters (will soon implement National Instruments' LabView software).

Data Analysis & Reporting

- Evaluate system parameters including but not limited to
  - system efficiency including balance of plant,
  - ramp rate,
  - system operating temperature,
  - performance to specifications,
  - system reliability, and
  - power electronic and balance of plant operation.
- Analyze system performance relative to standards & applications.
- Develop new testing procedures.
- Support developing new energy storage standards.
- Issue reports of findings.

Figure F-1. Energy Storage Test Pad Overview
(Sandia National Laboratories)

Energy Storage System Analysis Laboratory (ESAL) Overview

Capability/Capacity

- 14 channels from 36V, 25A to 72V, 1000A for battery, string and module-scale tests
- Over 125 channels; 0V to 10V, 3A to 100+A for cell tests
- Potentiostat/galvanostats for spectral impedance
- Multimeters, shunts and power supply for high precision testing
- Temperature chambers
- IR camera

Testing Activities

- Reliable, independent, third party testing and verification of advanced energy technologies for cells to systems
- Expertise in testing programs to customers
- Characterization testing of storage technologies
- Capabilities and investment in long term, application specific, cycle life testing
- Opportunities to conduct joint projects and publish testing results, or provide test results for internal use to companies and researchers

Data Analysis & Reporting

- Evaluate storage device performance including
  - system efficiency
  - capacity
  - DC Ohmic Resistance
  - AC Spectral Impedance
  - power density & specific energy
- Cycle test capabilities including efficiency and capability as a function of cycle life under cycle testing
- Development of new testing procedures
- Leverage Sandia capabilities and subject matter experts in
  - battery material synthesis
  - prototyping
  - modeling
  - diagnostics,
  - safety research and abuse testing
  - life cycle testing, materials synthesis
  - sensors and controls
- Issue public or private report of findings

Figure F-2. Energy Storage System Analysis Laboratory Overview
(Sandia National Laboratories)

Figure F-3. Energy Storage Test Pad at Sandia National Laboratories, Albuquerque, NM

F.2 Energy Storage Performance Test Laboratory, DNV-KEMA

The Energy Storage Performance Test Laboratory (ESPTL) is owned by DNV-KEMA and was commissioned in 2010. It can test energy storage systems at various loading conditions, according to industry standards or to specific customer requirements. Its capabilities include:

- Maximum Power: 2 MW.
- Output Voltage: 100 V, 240 V, 480 V, 600 V, 830 V; three or single phase.
- Maximum Output Current: 3,000 A at any voltage tap.
- Charge/Discharge Source: Synchronized with local utility network.
- Test Area: Outdoor 100 ft. × 60 ft.; indoor 30 ft. × 20 ft.
- Through this test circuit, ESPTL can connect a storage system to the utility electric grid, which can be used as both a power source in the charge mode and a load in the discharge mode. Providing real-life test conditions assures the end user that the storage system has been evaluated in the most realistic methods possible.

The ESPTL's control and instrumentation system can be programmed to execute various charge and discharge cycles and levels, measure and record several ac/dc voltages and currents simultaneously, and contact functions and temperatures. This system has a load-modeling tool to validate a storage system's response to simulated utility services and use cases, including market-based regulation through power dispatch, ramp rate regulation for distributed wind and solar resources, and critical peak price response. The facility can also test interconnection compatibility according to IEEE 1547.

The control and instrumentation system can also be interconnected to the actual grid through live signal feeds from PJM Interconnect, available at DNV-KEMA-Powertest. This enables real-life test conditions to be replicated in the test environment to evaluate functions like frequency and ramp rate.

For additional information on ESPTL, or to reserve it for testing a storage system go to: http://www.dnvkema.com/.

F.3 EPRI Knoxville Test Facility

- EPRI'S Knoxville, TN, test facility was prepared for expanded Distributed Energy Storage System (DESS) testing
- Has outdoor bay and anti-islanding test features
- High-resolution data-acquisition capability
- Environmental chambers if needed
- 1-MW total single-size capability

F.3.1 Used to Test Storage System Prototypes as Well as Units for Field Deployment and Demonstration

F.3.2 Energy Storage Grid Integration – Testing and Modeling

- Obtain real charge/discharge data from DESS evaluation in laboratory
- Several DESS evaluations planned
- Develop open DESS models based on gathered experimental data

F.3.3 Test and Research Services

- Energy Efficiency and Demand Response: Develop test protocols, test energy-saving devices, and test lighting technologies or conduct field demonstrations of emerging technologies.
- Distributed Resources: Test inter-connection hardware as well as test and evaluate energy-storage technologies, from batteries to superconductors.
- System Compatibility: Evaluate the capabilities of devices in electrical environments, provide design expertise, and conduct voltage-sag testing with the industry-leading Porto SagSM portable voltage-sag test equipment.
- Intelligent Electronic Device Testing: Test revenue meters, protective relays and controls for distribution, and transmission equipment. Also perform data integration, system compatibility, accuracy, and communication testing.
- Electromagnetic Compatibility (EMC) Testing: Perform emissions tests, evaluate compatibility, provide field audits, and provide design assistance.
- Custom Metering and Monitoring: Design and test custom metering systems measuring energy usage, power quality, electromagnetic emissions and environmental conditions. Provide data integration and analysis, using tools such as EPRI's PQView software.
- Line Design and Performance: Conduct simulation of line voltage, geometry and phase spacing, as well as hybrid transmission studies.
- Insulator Performance: Conduct simulations of insulator contamination and contamination flashover testing.
- Insulator Aging: Perform accelerated aging of insulators and line components, including analysis in a variety of service environments.
- Lightning Performance: Simulate lightning and switching over-voltages and impulse surges for low-voltage, medium-voltage and high-voltage equipment.
- Corona: Investigate corona phenomena, including measurement of corona loss, audible noise, and radio and television interference. Line compaction also studied.
- Manhole Design and Performance: Simulate manhole events and test mitigation methods.
- High-voltage and Medium-voltage Inspections and Failure Analysis: Inspect transmission and distribution lines and substation components, including infrared, corona, splice resistance, and electric and magnetic fields.

Additional information can be found at: http://www.epri.com/Pages/Default.aspx.

F.4 Bonneville Power Authority Energy Storage Test Facility

The Bonneville Power Authority (BPA) Energy Storage Test Facility (ESTF), located in Vancouver, WA, provides a suitable energy storage testing facility for various energy storage technologies. Major features that establish the BPA Laboratory ESTF as a unique resource suited for testing energy storage technologies include:

- Single-phase power frequency testing (60 Hz), up to 1,100,000 V
- Lightning and switching impulse up to 5,600,000 V
- Existing (upgradable) dedicated 5-MVA interconnection to the Ross Switch Yard
- Supply voltage, 13.8 kV, adjustable +/- 15% under load
- Three-phase voltage and current instrumentation in place
- Existing adjacent railroad service
- Exceptional road access for large loads
- Lots of expansion space on paved, fenced area
- Accessible interconnection to the BPA Dittmer Control Center
- For more information on this facility: http://www.bpa.gov/Pages/home.aspx

F.5 NREL Energy Systems Integration Facility

National Renewable Energy Laboratory's (NREL) Energy Systems Integration Facility (ESIF) focuses on the integration of energy storage systems (both stationary and vehicle-mounted) and the interconnection with the utility grid. Although the focus of the facility is on battery technologies, it will also host ultra-capacitors and other electrical energy storage technologies. Facility capabilities include hardware-in-the-loop at megawatt-scale power, a high-performance data computing center, SCADA, and data analysis and visualization with electricity laboratories, thermal laboratories, and fuel laboratories[1].

For more information: http://www.nrel.gov/esi/esif.html.

[1] http://www.nrel.gov/esi/esif.html, last accessed March 11, 2013.

APPENDIX G: NOTEWORTHY PROJECTS

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G.1 Noteworthy Historical Electricity Storage Projects

Electricity storage projects from the 1980s provided valuable operating experience in utility service and influenced the design and operation of later projects. The list below is a chronological sequence of significant projects, mostly in the United States, with a brief notation of the role they played in the understanding of electricity storage in utility applications.

G.1.1 Crescent Electric Membership Cooperative (now EnergyUnited)

- Grid Service: Peak shaving
- Project Location: Statesville, NC
- Commissioned: 1987
- Power/Energy: 500 kW/500 kWh
- Battery Type: Lead-acid, flooded cell, by GNB Industrial Battery (now Exide)

NOTE: This was the first application of electricity storage in the United States for peak shaving in the grid. The battery operated from 1987 to 2002, well past its warranty of 8 years and 2,000 cycle projected life. The long life of the battery could be attributed to its robust construction, regular maintenance, and operation within its design envelope.

G.1.2 Berliner Kraft- und Licht (BEWAG) Battery System

- Grid Service: Frequency Regulation and Spinning Reserve
- Project Location: (Then West) Berlin, Germany
- Commissioned: 1987
- Power/Energy: 8.5 MW in 60 minutes of frequency regulation; 17 MW for 20 minutes of spinning reserve/14 MWh
- Battery Type: Lead-acid, flooded cell, by Hagen

NOTE: This was the largest battery project in the world at that time and provided essential support to the West Berlin electric grid when East and West Berlin were still divided and the West Berlin grid was an electric island. This project also represented a departure from the traditional peak-shaving application concept and successfully demonstrated the feasibility of stacked services – frequency regulation and spinning reserve – that was a critical reliability requirement for the grid due to West Berlin's geographic and electrical isolation. The stacked services were replicated later in the Puerto Rico Electric Power Authority (PREPA) battery storage project that was commissioned in 1994. The BEWAG battery was decommissioned in 1995 after it reached the end of its design life.

G.1.3 Southern California Edison

- Grid Services: Demonstrate load-leveling, transmission line stability, T&D deferral, local VAR control, and local area black start
- Project Location: Chino, CA
- Commissioned: 1988
- Power/Energy: 10 MW/40 MWh
- Battery Type: Lead-acid, flooded cell, by Exide

NOTE: The Chino project was an early demonstration of a large battery for multiple applications in the U.S. grid. The project was jointly sponsored by EPRI, DOE, and the International Lead Zinc Research Organization (ILZRO), supported by SCE as the host utility. This landmark project provided valuable experience with maintaining large banks of flooded lead-acid batteries and high-voltage battery strings. The lessons learned in this project influenced later battery projects and also spurred the development of smaller modular storage systems versus large field-assembled battery systems. The Chino project was also the largest utility battery system in the world until the PREPA BESS and later the Fairbanks battery projects were commissioned in 1994 and 2003, respectively. The Chino battery was decommissioned in 1997.

G.1.4 Puerto Rico Electric Power Authority (PREPA)

- Grid Services: Frequency control and spinning reserve
- Project Location: Sabana Llana substation, San Juan, Puerto Rico
- Commissioned: 1994
- Power/Energy: 20 MW/14 MWh
- Battery Type: Lead-acid, flooded cell, by C&D Battery

NOTE: Like the BEWAG battery described earlier, the PREPA BESS also provided frequency regulation and spinning reserve service to the island grid of Puerto Rico. This battery system demonstrated that the faster response of a battery system is a valuable feature for the grid, especially an island grid and is superior to CTs for frequency regulation and spinning reserve duty. Operational issues that surfaced soon after the battery was commissioned showed that frequency regulation duty requires far more cycling of the battery than originally estimated in the design and engineering phase of the project. The battery was decommissioned in 1999.

G.1.5 Oglethorpe Power Company – PQ2000 installation

- Grid Services: Power quality, UPS on customer-side-of-meter
- Project Location: Brockway Standard Lithography Plant, Homerville, GA
- Commissioned: 1996
- Power/Energy: 2 MW/55 kWh (10-second discharge)
- Battery Type: Lead-Acid, Low-Maintenance, truck-starting batteries by Delco

NOTE: The Oglethorpe demonstration of the PQ2000 represented the first use of a factory-assembled, transportable battery system – compared to the site-assembled battery projects that preceded it. Its successor versions are currently manufactured and marketed by S&C Electric under the Pure Wave trade name. The design was originated by the AC Battery[1] and first introduced as the PM250 by Omnion Power Engineering and was subsequently acquired by S&C Electric in 1999.

[1] Patent Number 4,894,764, "Modular AC Output Battery Load Levelling System," issued to John F. Meyer and David G. Porter, January 16, 1990.

G.1.6 Metlakatla Power and Light (MP&L)

- Application: Voltage regulation to displace diesel generation
- Project Location: Metlakatla, AK
- Commissioned: 1997
- Power/Energy: 1 MW/1.4 MWh
- Battery Type: Valve-regulated lead-acid (VRLA) Absolyte IIP, by GNB Industrial Battery (Now Exide)

NOTE: The MP&L battery was installed to counter the effects of large voltage swings in the Annette Island grid caused by the intermittent operation of large 400 and 600 hp motors in a lumber mill on the island. The battery displaced a 3.3-MW diesel that was operated at partial load to mitigate the voltage swings. The diesel supplemented two hydro units that are the main generation source for the island. The battery was very well managed and outlived its warranty of 8 years. It was replaced in 2008 after 12 years of service.

G.1.7 Golden Valley Electric Association (GVEA)

- Application: VAR Support, spinning reserve, power system stabilization
- Project Location: Fairbanks, AK
- Commissioned: 2003
- Power/Energy: 27 MW/14.6 MWh
- Battery Type: Nickel/cadmium, by Saft

NOTE: The Fairbanks battery is currently the largest in the United States and the only one using NiCd batteries. This battery storage system is not only the largest, but also provides a real-world example of the successful stacking of several grid services, including voltage support, spinning reserve, and reserve power for Fairbanks in the event of an outage on the transmission line connecting Fairbanks to Anchorage.

G.1.8 ARRA-Funded Electricity Storage Projects

In 2009, the DOE launched a significant electricity storage program with funding from ARRA. ARRA provided $185 million in federal matching funds to support storage projects with a total value of $772 million. These projects generated 537 MW of new storage to be added to the grid. These storage projects and their description are listed in Table G-1.

Table G-1. ARRA Energy Storage Demonstrations (T53)

ARRA ENERGY STORAGE PROJECTS				
RECIPIENT	**PROJECT TITLE**	**PROJECT DESCRIPTION**	**COM-MISSIONED DATE (Plan or Actual)**	**STATUS NARRATIVE (As of February 2013)**
SustainX	Demonstration of Isothermal Compressed Air Energy Storage to Support Renewable Energy Production	1.5MW/1MWh non-grid-tied aboveground isothermal compressed air energy storage (CAES) pilot system	Nov 2013	Fabricating/assembling full-scale pilot ICAES system for 9 month pilot test (non-grid-tied).
City of Painesville	Painesville Municipal Power Vanadium Redox Battery Demonstration Program	1 MW/8MWh vanadium redox flow battery for load following for Painesville Municipal Power station	Late 2013	Essentially all R&D has been completed. Battery building construction complete. Ready to gear up for production of flow battery stacks.
Aquion Energy	Demonstration of Sodium-ion Battery for Grid-level Applications	Demonstrated Aquion Energy's 10-15 kWh prototype sodium ion battery at Aquion's facility (non-grid tied)	NA	Project Completed
New York State Electric & Gas Corp.	Advanced CAES Demonstration 150 MW Plant Using an Existing Salt Cavern	150MW compressed air energy storage system for bulk energy storage. Project has been terminated.	NA	Recipient requested termination after phase 1 feasibility study. Termination was effective Nov 2012. https://www.smartgrid.gov/document/seneca_compressed_air_energy_storage_caes_project
Amber Kinetics	Demonstration of a Flywheel System for Low Cost, Bulk Energy Storage	20KW (2 x 10kW) flywheels storing 80kWh energy in a pilot demo for demand management in SDG&E territory	January 2014	Beginning phase 2 scale-up for grid-tied demo with commercial partner/customer. http://www.smartgrid.gov/sites/default/files/pdfs/tpr_final_phase1_amber_kinetics.pdf

ARRA ENERGY STORAGE PROJECTS				
RECIPIENT	**PROJECT TITLE**	**PROJECT DESCRIPTION**	**COM-MISSIONED DATE (Plan or Actual)**	**STATUS NARRATIVE (As of February 2013)**
Public Service Company of New Mexico (PNM)	PV Plus Battery for Simultaneous Voltage Smoothing and Peak Shifting	750KW/2.8MWh advanced lead acid battery for voltage smoothing and PV firming on PNM distribution feeder.	Sept 2011	1.5 years into a 2-year demo. Executing various test plans for smoothing, shaving, and firming. Also working on predictive models for cloud cover. http://www.smartgrid.gov/sites/default/files/pdfs/PNM_TPR_rev2_09_24_12.pdf
Detroit Edison Company	Detroit Edison's Advanced Implementation of Community Energy Storage Systems for Grid Support	S&C Electric, 18 CES units DowKokam Li-ion batteries, 2 CES units secondary use EV batteries Li-ion Bosch Batteries for distribution side service providing aux. power for increase service reliability and quality.	June 2013	5 CES units are currently being installed.
Hazle Spindle LLC (Beacon Power)	Beacon Power 20MW Flywheel Frequency Regulation Plant	20MW (200 x 100KW) flywheels for frequency regulation in PJM	Sept 2011	Site clearing has been completed. Rough grading well underway. Majority of equipment and material orders have been placed. GC has been selected for site construction.
Primus Power Corporation	Wind Firming EnergyFarm™	25MW/75MWh zinc bromine flow battery system for wind firming in Modesto Irrigation District	August 2014	Design has been frozen. Beginning to fabricate pilot stacks for pilot testing and 3rd party validation testing. Once complete, design may be refined using knowledge gained. Full-scale production of demo stacks will follow.
Raytheon Ktech	Flow Battery Solution for Smart Grid Renewable Energy Applications	250kW/1MWh EnerVault Iron Chromium flow battery for firming PV	October 2013	Detailed design for a 250 kW system is complete and system components procurements are underway.
Seeo Inc.	Solid State Batteries for Grid-Scale Energy Storage	~25kWhr Seeo prototype in conjunction with solar PV	June 2013	Prototype pack design is complete and the pack manufacture is in process.
Pacific Gas & Electric	Advanced Underground CAES Demonstration Project Using a Saline Porous Rock Formation as the Storage Reservoir	300MW CAES	March 2021	Candidate sites were selected from counties east of San Francisco and core well samples are being taken to select optimum site for pressure testing.

ARRA ENERGY STORAGE PROJECTS				
RECIPIENT	**PROJECT TITLE**	**PROJECT DESCRIPTION**	**COM-MISSIONED DATE (Plan or Actual)**	**STATUS NARRATIVE (As of February 2013)**
East Penn Manufacturing	Grid-Scale Energy Storage Demonstration for Ancillary Services Using the UltraBattery™ Technology	3MW East Penn UltraBattery (ultra-capacitor/lead-acid) providing frequency regulation services	June 2012	The energy storage system initiated operations in June 2012 providing frequency regulation services to the grid of PJM interconnection.
Premium Power	Distributed Energy Storage System Demonstration	1 MW Premium Power zinc bromine flow battery	2014/2015	Demonstration in conjunction with National Grid in planning.
Southern California Edison	Tehachapi Wind Energy Storage Project	8MW (32 MWh) Li-ion battery at substation within Tehachapi Wind Resource Area for voltage support, wind integration, frequency regulation, arbitrage	Early 2014	The majority of the construction activities are complete. Review and selection of battery provider in process.
Duke Energy Business Services	Notrees Wind Storage	36MW/24MWh Xtreme Power advanced lead acid battery for Wind Farm storage for frequency regulation as the targeted service.	January 2013	Operational. Gathering data.
Batelle Memorial Institute	Pacific Northwest Smart Grid Demonstration Project	42kW/170kWh Demand Energy Networks advanced lead acid batteries (4 x 10kW/40kWh units + 2 x 1kW/5kWh units) for peak load management, demand response, and renewables firming	March 2012	Operational
		125kW/125kWh ZBB zinc bromine flow battery peak load, demand response, and renewables firming	March 2013	Operational
		5MW/1.25MWh EnerDel Li-ion battery for high-reliability zone/microgrid support.	March 2013	To be located in Salem, OR
Long Island Power Authority	Long Island Smart Energy Corridor	12 sealed AGM lead acid batteries planned for demonstration of storage in the residential demonstration model at Farmingdale; 60 Amp, 720W, 12V.	July 2013	AGM-absorbed glass mat
Kansas City Power & Light Co	KCP&L Green Impact Zone Smart Grid Demonstration	1MW/1MWh (13.2kV) Superior Lithium Polymer Battery Storage (SLPB) system, grid-connected	June 2012	Operational

ARRA ENERGY STORAGE PROJECTS				
RECIPIENT	**PROJECT TITLE**	**PROJECT DESCRIPTION**	**COM-MISSIONED DATE (Plan or Actual)**	**STATUS NARRATIVE (As of February 2013)**
AEP Ohio	gridSMART℠ Demonstration Project	100kW/100kWh (4 units @ 25kW each) S&C Electric PureWave Li-ion batteries for Community Energy Storage	TBD	15 of the 80 planned units were installed and subsequently removed from service and returned to the vendor for troubleshooting due to technical issues.
Consolidated Edison Company of NY	Secure Interoperable Open Smart Grid Demonstration	Battery storage at 7 locations, lithium phosphate, capacity range is 25-200kWh, 40-500kW maximum output	May 2013	Three units have been installed. PI indicates that remaining four installations may be dropped. http://www.smartgrid.gov/sites/default/files/OE0000197-Con-Edison-Technology-Performance-Report-July%205%202012-Revision_1.pdf.
Center for Commercialization of Electric Technologies	Technology Solutions for Wind Integration in ERCOT	1MW/1MWh Xtreme/Samsung Li-ion battery for wind integration with Texas Tech and the South Plains Electric Coop	Dec 2013	Purchase order issued for battery.
Southern California Edison	Irvine Smart Grid Demonstration	17 homes with Residential Energy Storage Units (4kW/10kWh LG Chem Li-ion battery)	July 2013	LG batteries are automotive grade.
		9 homes will share a community energy storage unit (25kW/50kWh battery)	July 2013	
		100kW/90kWh battery supporting a grid-connected PV charging station for 20 cars.	July 2013	
University of Hawaii	Managing Distribution System Resources for Improved Service Quality and Reliability, Transmission Congestion Relief, and Grid Support Functions	1MW/1MWh A123 Li-ion battery installed at Wailea substation	April 2013	Supports reactive power and peak demand management.
University of Nevada Las Vegas (UNLV)	Integrated PV, Battery, Storage, and Customer Products with Advanced Metering	9 units - Silent Power On Demand Energy Appliances (9.2 kW/8.8kWh each Saft Li-ion batteries) for peak shaving and PV integration sized for individual homes.	June 2015	One unit installed as of February 2013, the remainder to be installed by June 2015.

ARRA ENERGY STORAGE PROJECTS				
RECIPIENT	**PROJECT TITLE**	**PROJECT DESCRIPTION**	**COM-MISSIONED DATE (Plan or Actual)**	**STATUS NARRATIVE (As of February 2013)**
ATK Launch Systems	Alliant Techsystems (ATK) Launch Systems Demonstration Project	300kW/1200kWh EaglePicher Technologies AGM Lead Acid Battery	June 2015	For peak shaving and integration of 100kW wind farm and 100 kW waste heat generation unit.
Consolidated Edison Co.	Interoperability of Demand Response Resources	Ice Storage Plant (10,000 cooling tons of ice)	July 2013	Goal is to reduce peak load by approximately 1000kW.
Allegheny Power	West Virginia Super Circuit	24kW/50 kWh Li-ion batteries (3 units @ 8 kW each) with target discharge duration of 2 hrs	Oct 2013	On a microgrid that includes 40kW of solar and 160kW natural gas backup generator.
Illinois Institute of Technology	IIT Perfect Power Demonstration	250kW/500kWh ZBB zinc bromine flow battery	January 2013	Unit was installed at Illinois Institute of Technology (IIT) Galvin Institute's "Perfect Power" campus micro grid project.

G.1.9 The DOE International Energy Storage Database[2]

The DOE has initiated an Internet-based, interactive compendium of energy storage projects and policies. The effort is relatively recent, but, it has already become a credible repository of structured information on projects that can be sorted by location, technology type, size, ownership, and current status. The process of obtaining and maintaining the database is on-going, and new information is being added to the database regularly. Figure G-1 shows a sample screen from the website.

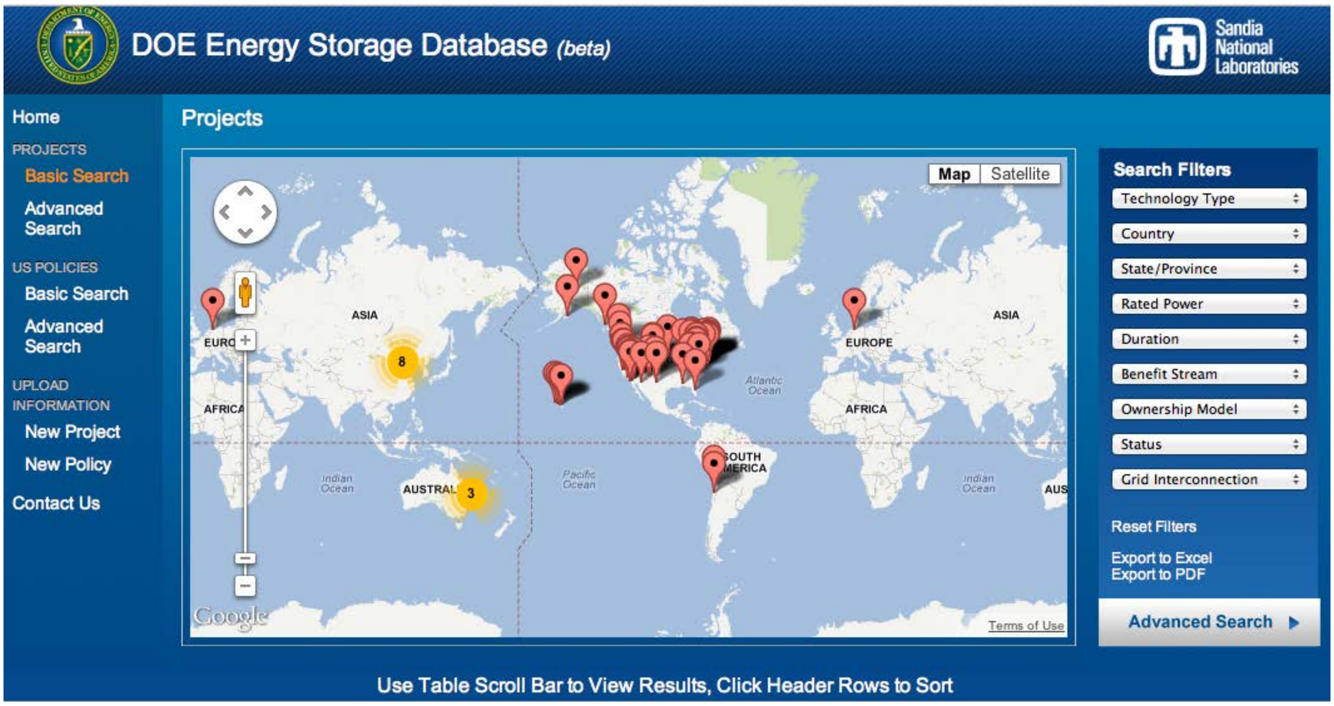

Figure G-1. Screenshot of DOE Energy Storage Database

2 http://www.energystorageexchange.org/projects, last accessed April 28, 2013.

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