Update to Energy Storage Screening Study For Integrating Variable Energy Resources within the PacifiCorp System

July 9, 2014

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1 EXECUTIVE SUMMARY

HDR Engineering (HDR) was retained by PacifiCorp Energy (PacifiCorp) to perform an Energy Storage Study to support PacifiCorp's 2013 Integrated Resource Plan (IRP) intended to evaluate a portfolio of generating resources and energy storage options. This report has been updated for the 2015 IRP. The scope of this Energy Storage Study is to develop a current catalog of commercially available utility-scale and distributed scale energy storage technologies, and to define their applications, performance characteristics, and estimated capital and operating costs. The information presented in this report has been gathered from public and private documentation, studies, reports, and project data of energy storage systems and technologies.

HDR has reviewed and investigated the following energy storage technologies for this study:

- Pumped Storage Hydroelectric
- Battery Energy Storage Systems
- Compressed Air Energy Storage

In addition, some less-than-utility-scale or emerging technologies are described without detailed discussion of cost or performance characteristics.

Pumped storage hydroelectric facilities are classified as a mass energy storage technology capable of providing thousands of megawatt hours (MWh) of dispatchable energy. Pumped storage is ideal for large grid applications such as load shifting, peak shaving, spinning reserve, and intra-second grid needs such as frequency regulation, all on a large scale (200 to 1,000+ MW). Due to the grid scale size of the projects interconnection of these facilities typically requires availability of Extra High Voltage (EHV) transmission lines. Furthermore, pumped storage facilities also require site-specific attributes and resources, such as water rights and elevated reservoir.

There are currently forty (40) pumped storage hydroelectric projects operating in the United States. In addition, there are currently over sixty (60) projects being considered for development under the Federal Energy Regulatory Commission (FERC) licensing process. Three projects within PacifiCorp's territory have been reviewed for this IRP update report: the JD Pool Pumped Storage Project, the Swan Lake North Pumped Storage Project, and the Black Canyon Pumped Storage Project. These proposed sites were selected based on existing project features located within the PacifiCorp balancing area, environmental impacts that are fairly well understood, and the current status of project development and licensing. Project parameters are summarized in Table 1 below.

Table 1 - Summary of Highlighted Pumped Storage Projects

Item	Swan Lake North	JD Pool	Black Canyon
Location	Oregon	Washington	Wyoming
Approximate Static Head (ft)	1,300	2,400	1,063
Energy storage (MWh)	5,280	16,500	5,550
Assumed Hours of Storage (hrs)	8.8	11	9.5

Item	Swan Lake North	JD Pool	Black Canyon
Estimated Installed Capacity (MW)	600	1,500	600
Developer Provided Estimated Capital Cost ($/kW) (See section 3.1.6 for details of HDR's Opinion of Costs)	$2,300	$1,700-$2,500	$1,500
Estimated Year 1 O&M Cost (estimated as a function of capacity and annual energy. See section 3.1.6 for details)	$9.4 million	$19.1 million	$9.4 million
Water-to-wire efficiency	75-82%	75-82%	75-82%

Battery storage is gaining acceptance in small-scale (~ 20 MW) storage applications, particularly in conjunction with renewable resources. Battery energy storage systems are considered to be a small scale energy storage option focused on applications such as energy regulation, frequency response, load following and ramping support, energy arbitrage, and even distribution system upgrade deferral. In the case of renewable integration, batteries primarily function to dampen the effects of generation and load differences resulting from the variability in renewable energy generation profiles. Battery technologies and their respective manufacturers reviewed for this study, including project characteristics, include the following:

- Lithium ion (Li-ion) – A123 Systems: Since 2009, seven projects have been installed in the US with capacity of 69 MW / 47.5 MWh. Largest projects include 20 MW / 5 MWh in Johnson City, NY and 8 MW / 32 MWh in Tehachapi, CA. Currently under development is a 32 MW / 8MWh system in Oro Mountain, WV.
- Sodium sulfur (NAS) – NGK Insulators, Ltd.: The first project was 0.5 MW for a TEPCO Kawasaki substation in 1995. Installations now include over 120 international projects with capacity of 190 MW and 1,300 MWh. The largest project is 12 MW / 86.4 MWh at a Honda facility Japan, installed in 2008. As of 2010, six projects in the US with 14.75 MW / 73.2 MWh have been installed, with the largest project being 4 MW / 24 MWh in Presidio, TX (2010). Five projects totaling 7.9 MW / 23.2 MWh are planned throughout the US.
- Vanadium Redox (VRB) – Prudent Energy: The first US project was with PacifiCorp in Castle Valley, UT with 0.250 MW / 2 MWh installed in 2004. In 2009, a 0.6 MW / 3.6 MWh system was installed at Gills Onion plant, CA. Two other projects are in development in CA, with combined nameplate capacity of 2.2 MW.
- Dry Cell – Xtreme Power, Inc.: The first installation of 0.5 MW / 0.1 MWh was a test facility in Antarctica for microgrid peak shaving completed in 2006. A 1.5 MW / 1 MWh test facility was installed in Maui, HI for renewable integration in 2009.
- Zinc Bromide (ZnBr) – Premium Power: To date, 6.9 MW / 17.2 MWh has been installed in the US. Five recent projects, two in CA and three in MA, have been installed or are under development, rated at 0.5 MW / 3 MWh each.

- Advanced Lead Acid (Pb-Acid) – Ecoult has installed a 3 MW scale demonstration facility, as well as a 3 MW frequency regulation facility on the PJM grid in Pennsylvania. Also installed has been a 3 MW micro-grid application that allows an island of 1,500 people to utilize 100% renewable energy.

Compressed Air Energy Storage (CAES) is also classified as mass energy storage, although on a capacity scale (~100 MW) between batteries and pumped storage. A typical CAES plant would consist of a series of motor driven compressors capable of filling a storage cavern with air during off-peak, low-load hours. At high-load, on-peak hours, the stored compressed air is delivered to a series of combustion turbines which are fired with natural gas for power generation. Utilizing pre-compressed air removes the need for a compressor on the combustion turbine, allowing the turbine to operate at high output and efficiency during peak load periods. Compressed air energy storage is the least implemented and developed of stored energy technologies evaluated herein. Only two plants are in operation, including Alabama Electric Cooperative's (AEC) McIntosh plant which began operation in 1991. Others projects have been proposed, but have not progressed beyond concept.

Other emerging energy storage technologies have been briefly reviewed for this report, including flywheels, liquid air energy storage, super-capacitors, and superconducting magnets. Although all of these technologies can be connected to the grid, they are still considered developmental and small scale. Generally, these other technologies could only be used for short durations (seconds to minutes), for supplying backup power in an outage event, or to help regulate voltage and frequency.

HDR has performed an initial comparison of the three primary energy storage technologies, including pumped storage, batteries and compressed air. Table 2 summarizes the comparison of key criteria for these technologies including project capital cost as evaluated by HDR in 2014 dollars. More detailed comparisons are included in Appendix A. HDR has also reviewed and commented upon the overall commercial development of these technologies, the applications which each technology is suited to, along with space requirements, performance characteristics, project timelines, and the Developer provided capital, operating and maintenance (O&M) costs.

There are challenges associated with comparing costs for these different types of energy storage technologies. Initial capital cost is one indicator; however long-term annual O&M cost provides another factor for comprehensive economics and determining financial feasibility. Operating and maintenance costs associated with various battery technologies can be high compared to pumped storage, but this cost varies depending upon the technology. As battery technology develops further, and grid scale installations continue, a better understanding of the costs associated with operation and maintenance will be achieved. Conversely, while the capital costs for pumped storage are high when looked at in total, they are competitive with batteries on a dollar/kW installed basis, and have low fixed and variable O&M costs.

Table 2 - Energy Storage Technology Summary Table

	Pumped Storage Hydro (Three sites)	Batteries	Compressed Air Energy Storage
Range of power capacity (MW)	600 – 1,500	1-32	100+
Range of energy capacity (MWh)	5,550 – 16,000	Variable depending on Depth Of Discharge	800+
Range of capital cost (2014$ per kW)	$1,700 - $2,500	$800 - $4,000	$2,000 - $2,300
Year of first installation	1929	1995 (sodium sulfur)	1978

2 INTRODUCTION

PacifiCorp, as well as other utilities and power authorities throughout the world, face a major challenge in balancing increasing levels of variable energy resources. As generation from variable energy resources and their relative percentage of load grow, there is an increasing need for additional system flexibility to assure grid reliability. Based on both industry and HDR studies, it is evident that expanded transmission interconnections, continued modernization of the existing power plants, market changes that encourage greater operational flexibility of existing generation assets and new energy storage facilities will be required across the United States over the next decade.

The 2015 PacifiCorp Integrated Resource Plan (IRP) is expected to include a portfolio of generating resources and energy storage options for evaluation. These include both fossil fuel options, such as coal and natural gas, as well as renewable options including wind, geothermal, hydro, biomass, and solar. In order to integrate additional renewable generation into their IRP, it is anticipated that energy storage may be required. For that reason, PacifiCorp has engaged HDR to develop a current catalog of commercially available and emerging energy storage technologies with estimates of performance and costs.

Energy storage permeates our society, manifesting itself in products ranging from small button batteries to large-scale pumped storage hydro-electric projects. Energy storage for utility-scale applications has historically relied upon pumped storage hydro facilities and the large reservoirs associated with conventional hydropower stations. In recent years, utilities have also considered and implemented several pilot projects utilizing various battery technologies. To a limited extent, compressed air energy storage and flywheels have also been implemented. When installed over a large service area, the totality of these distributed systems could provide reserves to the regional grid for limited durations. Within the electric utility industry, there is uncertainty regarding which energy storage system can provide the optimal benefit for a given application. The following discussion is intended to catalog the energy storage technologies available to date, to summarize the current state of development of these energy storage technologies, to provide a high level comparison of these technologies, and provide comments and discussion on their implementation in an effort to assist PacifiCorp with the integration of variable energy resources and energy storage into its IRP.

2.1 Integrating Variable Energy Resources

Variable energy resources provide a sustainable source of energy that uses no fossil fuel and produces zero carbon emissions. One of the constraints of variable generation is that the energy available is non-dispatchable; it tends to vary and is somewhat unpredictable. The power-system load is also variable; power-system reserves are required to match changes in generation and demand on a real-time basis. Variable generation cannot be dispatched specifically when energy is needed to meet load demand. Wind and utility industries have been able to address many of the variability issues through improvements in wind forecasting, diversification of wind turbine sites, improvements in wind turbine technology, and the creation of larger power-system control areas. At low wind penetration levels, wind output typically can be managed in the regulation time-frame by calling upon existing system reserves, curtailing output and/or diversifying the locations of wind farms over a broad geographic area.

As more variable energy is added to the power system, additional reserves are required. Flexible and dispatchable generators, such as hydro, CAES, or batteries, are required to provide system capacity and balancing reserves to balance load in the hour-to-hour and sub-hour time-frame. In addition to system reserves, every balancing authority has the need for energy storage to balance excess generation at night and shift its use to peak demand hours during the day. Conventional hydropower projects do this by shutting down units and storing energy in the form of elevated water, and it is the most common form of energy storage in the world. As variable energy output and the ratio of wind generation to load grows, historical system responses will need to be modified to take advantage of the benefits of variable energy resources to the regional grid and to assure system reliability.

It should be mentioned that variability is not a new phenomenon in power system operation. Demand has fluctuated since the first consumer was connected to the first power plant. The resulting energy imbalances have always had to be managed, mainly by dispatchable power plants. The evolution of variable energy resources in the system is an additional, rather than a new, challenge that presents two elements: variability (now on the supply-side as well), and uncertainty.

The output from variable energy resource plants fluctuates according to the available resource — the wind, the sun or the tides. These fluctuations are likely to mean that, in order to maintain the balance between demand and supply, other parts of the power system will have to change their output or consumption more rapidly and/or more frequently than currently required. At small penetrations — a few percent in most systems — the additional effort is likely to be slight, because variable energy resource fluctuations will be dwarfed by those already seen on the demand side.

Large variable energy penetration, in contrast, will exacerbate the system variability in extent, frequency and rate of change. As is known by system operators, electricity demand follows a regular pattern. Deducting the contribution of variable energy resources to the grid in correlation to demand is often referred to as the net load. In the review of net load tracking in the Bonneville Power Administration balancing area, no regular pattern is evident with the exception of a tendency for wind to pick up at night and drop off in the morning. This is opposite to electric demand, which highlights the greater variability of net load caused by a 30 percent penetration of variable supply.[1]

It is the extent of these ramps, the increases or decreases in the net load, as well as the rate and frequency with which they occur that are of principal relevance to the industry. This is where the balancing challenge lies — in the ability of the system to react quickly enough to accommodate such extensive and rapid changes. Net load ramping is more extreme than demand alone. This is not only because variable energy resource output can ramp up and down extensively over just a few hours, but also because it may do so in a way that is inversely proportional to fluctuations in demand. In contrast, VER output may complement demand — when both increase or decrease at the same time.

So, rather than the question of — how can variable renewables be balanced? — the more pertinent may be: how can increasingly variable net load be balanced? The point is that variability in output (supply) should not be viewed in isolation from variability on the demand-side (load); if the variable energy resource side of the balancing equation is considered separately, a system is likely to be under-endowed with balancing resources.[2]

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[1] Hydroelectric Pumped Storage for Enabling Variable Energy Resources within the Federal Columbia River Power System, Bonneville Power Administration, HDR 2010

[2] Harnessing Variable Renewables *A Guide to the Balancing Challenge*, 2011 International Energy Agency

3 ENERGY STORAGE SYSTEMS AND TECHNOLOGY

A review of available energy storage technologies was performed for comparative purposes in this study. The results are discussed throughout this report and include the following storage systems:

- Pumped Storage Hydroelectric
- Battery Energy Storage Systems
- Compressed Air Energy Storage

Each of these technologies has been employed for grid scale storage or to provide ancillary services. Many other technologies, such as flywheels, superconducting magnets, and supercapacitors, have been deployed at the distributed-energy scale, and there is significant ongoing research to further develop these technologies and scale them up for bulk energy storage applications. This research is expected to continue for the foreseeable future.

3.1 Pumped Storage

Pumped storage hydroelectric projects have been providing storage capacity and transmission grid ancillary benefits in the U.S. and Europe since the 1920s. Today, there are 40 pumped storage projects operating in the U.S. that provide more than 20 GW, or nearly 2 percent, of the capacity for our nation's energy supply system (Energy Information Admin, 2007). Figure 1 below indicates the distribution of existing pumped storage projects in the U.S. Pumped storage and conventional hydroelectric plants combined account for approximately 77 percent of the nation's renewable energy capacity, with pumped storage alone accounting for an estimated 16 percent of U.S. renewable capacity (Energy Information Admin., 2007).

Figure 1 - Existing Pumped Storage Projects in the United States

Pumped storage facilities store potential energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation (Figure 2). Historically, pumped storage projects were operated in a manner that, during periods of high electricity demand, electricity is generated by releasing the stored water through pump-turbines in the same manner as a conventional hydro station. In periods of low energy demand or low cost, usually during the night or weekends, energy is used to reverse the flow and pump the water back up hill into the upper reservoir. Reversible pump-turbine/generator-motor assemblies can act as both pumps and turbines. Pumped storage stations are unlike traditional hydro stations in that they are actually a net consumer of electricity, due to hydraulic and electrical losses incurred in the cycle of pumping back from a lower reservoir to the upper reservoir. However, these plants have often proved very beneficial economically due to peak to off-peak energy price differentials, and as well as providing ancillary services to support the overall electric grid.

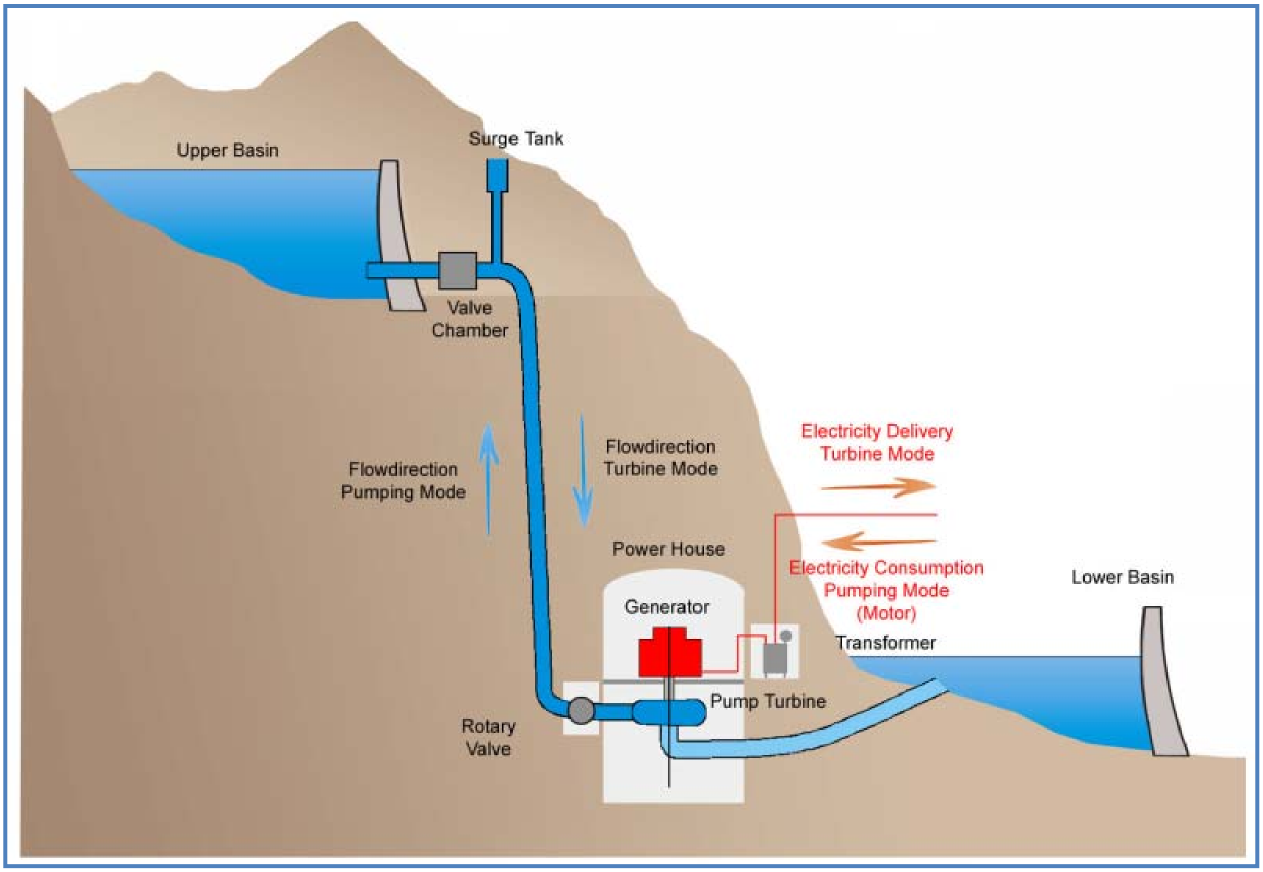


Figure 2 - Typical Pumped Storage Plant/System

The contributions of pumped storage hydro to our nation's transmission grid are considerable, including providing stability services, energy-balancing, and storage capacity. Pumped storage stations also provide ancillary electrical grid services such as network frequency control and reserves. This is due to the ability of pumped storage plants, like other hydroelectric plants, to respond to load changes within seconds. Pumped storage historically has been used to balance load on a system and allow large, thermal generating sources to operate at peak efficiencies. Pumped storage is the largest-capacity and one of the most cost-effective forms of grid-scale energy storage currently available.

3.1.1 Single-Speed versus Variable-Speed Technology

Historically, typical pumped storage plants used electricity to pump water to the upper reservoir during periods of low-cost, off-peak power and generate electricity during periods of high-cost, on-peak power. New pumped storage projects are envisioned to provide significant load following or ramping capability to the grid during periods of rapid changes in net load (load minus wind or solar generation) in addition to energy absorption or pumping capability during periods of excess energy generation.

In the case of conventional synchronous (single, constant speed) pump-turbine units, during generating mode, the individual units are operated to support grid requirements including load following and frequency regulation (Automatic Generation Control or AGC); however, during pumping, the units are operated at best pumping gate (most efficient operation) with no capability for load following or regulation. During pumping mode, the wicket gate positions may need to be decreased as the reservoir water elevation increases in order to keep the units on the best pumping gate curve and to prevent cavitation and vibration (net head control). Deviation from this best pumping gate operation results in low efficiency and rough operation, with minimal change in power input requirements.

Many of the proposed pumped storage projects are considering variable-speed (asynchronous) pump-turbine technology where load following is possible during both the generating and pumping modes, and hence the primary difference between the two technologies. This allows a pumped storage owner to provide grid reliability services in both pump and generate modes of operation. Variable-speed operation in this context normally means that the rotating speed of a unit does not vary by more than +/-10% of its synchronous speed. The varying output frequency of the generator is converted to the grid frequency through a special frequency conversion system. Other advantages of variable-speed units are higher and flatter generator efficiency curves, wider generating and pumping operating ranges, and easier start-up process. The main disadvantage of this technology is the higher capital costs, which are on average about 30% greater than conventional single-speed units.

Table 3 provides a summary comparing the operational characteristics and advantages/disadvantages of single and variable-speed units for an example particular project. Actual benefits will vary depending on specific site characteristics. Because of the multiple advantages, variable-speed units have been discussed in this report.

Table 3 - Example Comparison of Primary Characteristics

Characteristic	Single-speed	Variable-speed
Proven Technology	45+ years - Worldwide	10+ years - Europe and Japan
Equipment Costs	-	Approximately 10% to 30% Greater
Powerhouse Size	-	Approximately 25% to 30% Greater
Powerhouse Civil Costs	-	Approximately 20% Greater
Project Schedule	-	Longer - Site Specific
O&M Costs	-	Greater for the Power Electronics
Operating Head Range	80% to 100% of Max. Head	70% to 100% of Max. Head
Generating Efficiency		Approximately 0.5% to 2% Greater
Power Adjustment Generation Mode*	Approximately 60% to 100%	Approximately 50% to 100%
Power Adjustment Pump Mode*	None	+/- 20%
Operating Characteristics		
Idle to Full Generation	Generally Less than 3 Minutes	Generally Less than 3 Minutes
100 Percent Pumping to 100 Percent Generation	Generally Less than 6 to 10 Minutes	Generally Less than 6 to 10 Minutes
100 Percent Generation to 100 Percent Pumping	Generally Less than 6 to 10 Minutes	Generally Less than 6 to 10 Minutes
Load Following	Seconds (i.e., 10 MW per Second)	Seconds (i.e., 10 MW per Second)
Reactive Power Changes	Instantaneously	Instantaneously
Automatic Frequency Control	Yes in generate mode	Yes in both pump and generate modes

***Power Adjustment:** The ability of a pump-turbine generator-motor to operate away from its best operating point based on rated head and flow. Single-speed units can operate over a range of flow in the generating mode which is identical to a conventional hydropower turbine, but not in the pumping mode (in pumping mode a single speed machine cannot vary flow or wicket gate settings at all). Variable-speed units have the ability to operate the turbine's off-peak efficiency point in the pumping mode via the power electronics (no substantive change in flow), and typically have greater flexibility in the generating mode than single-speed units.

3.1.2 Open-Loop and Closed-Loop Systems

Both open-loop and closed-loop pumped storage projects are currently operating in the U.S. The distinction between closed-loop and open-loop pumped storage projects is often subject to interpretation. The Federal Energy Regulatory Commission (FERC) offers the formal definitions for these projects, and it was FERC's definitions that were followed while categorizing the pumped storage sites discussed in this report: Closed-loop pumped storage are projects that are not continuously connected to a naturally-flowing water feature; and open-loop pumped storage are projects that are continuously connected to a naturally-flowing water feature.

Closed-loop systems are preferred for new developments, or Greenfield projects, as there are often significantly less environmental issues, primarily due to the lack of aquatic resource impacts. Projects that are not strictly closed-loop systems can also be desirable, depending upon the project configuration, and whether the project uses existing reservoirs.

3.1.3 Potential Projects in PacifiCorp Service Area

For PacifiCorp's 2013 IRP, HDR made an assessment of fifteen potential projects located within the PacifiCorp balancing area. For the 2015 IRP, three projects have been selected in consultation with PacifiCorp for further review. Projects were selected based on the preliminary filings with FERC. Figure 3 below illustrates where proposed projects in the U.S. that have been granted and/or filed for a FERC Preliminary Permit Application.

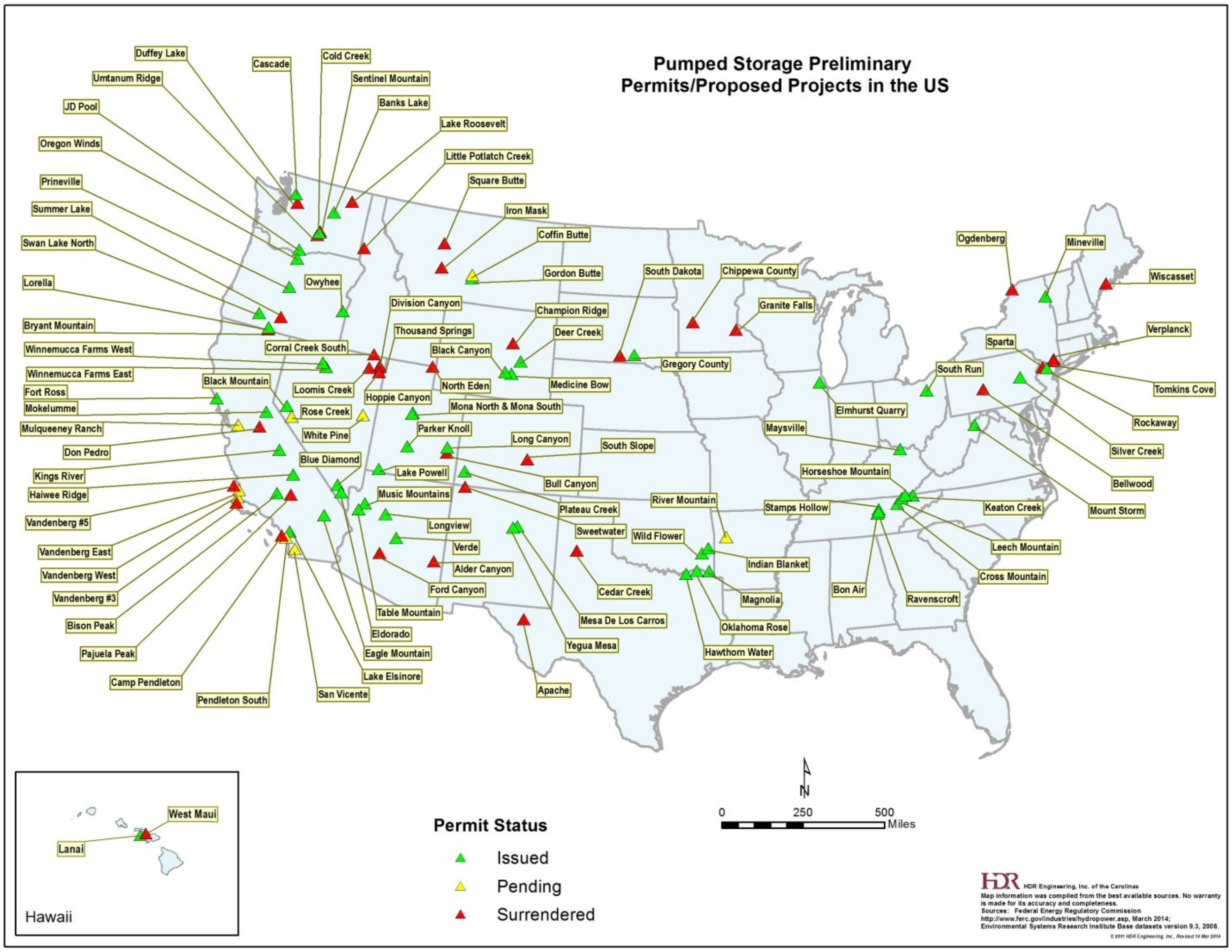


Figure 3 - Preliminary Proposed Pumped Storage Projects as of April, 2014 (HDR)

3.1.3.1 Pumped Storage Evaluation Criteria

The following is a list of pumped storage evaluation criteria utilized for this study:

Water conveyance – The tunnel length to head ratio is the single biggest variable cost component for a pumped storage project. The higher the head, the higher energy density and, as such, longer tunnel lengths are justifiable. Conversely, lower head (less than 300 feet) means that shorter tunnel lengths or a unique site configuration are required to be competitive.

Capacity- The larger the project is in terms of capacity, the lower the installed cost per kilowatt (kW) is for similar civil cost components.

Closed or open-loop- Closed-loop or off-stream embankments/dams generally means fewer regulatory challenges and a less complex FERC licensing process. Specific sites where the lower reservoir already exists may also be advantageous.

Source of water- The source of water can be complicated in extremely dry (e.g. desert southwest) or politically charged (Columbia River Basin) areas of the country.

Potential environmental/regulatory factors- Environmental and regulatory factors vary widely from site to site: these issues can range from minor challenges to a fatal flaws depending upon the project's environmental impacts.

Project location- A strong power market where ISO's are integrating large amounts of variable energy will be seeking a project that can provide grid scale ancillary services.

Transmission access- Energy evacuation and transmission line permitting is site specific and driven by a local project champion.

Geological factors- Geological factors, such as active fault lines near the proposed site, can be a project fatal flaw if known or suspected.

Technical development progress- HDR has evaluated the technical progress thus far of each project. Projects with more than a conceptual layout have been favored.

Commercial development progress- HDR has evaluated the commercial analysis of each project, as initially performed by others, and has investigated whether the developer has explored the revenue streams beyond the traditional energy arbitrage model.

Based on the above criteria, and the location of the projects within PacifiCorp's regional footprint, HDR, in collaboration with PacifiCorp, selected the JD Pool Pumped Storage Project, the Swan Lake North Pumped Storage Project and the Black Canyon Pumped Storage Project for further evaluation. These proposed sites were selected due to existing project features, environmental impacts that are fairly well understood, and the current project development status. HDR reviewed the FERC preliminary filings and subsequent six-month progress reports for each site. In addition, the developers for each project were contacted for additional information. A request for information (RFI) was developed and distributed to Klickitat Public Utility District (Klickitat) for JD Pool, EDF Renewable Energy (EDF) for Swan Lake North, and Gridflex for Black Canyon, respectively. The RFI and each developer's response are attached to this document in Appendix B. Table 4 below discusses a summary of these projects' characteristics.

Table 4 - Summary of Highlighted Pumped Storage Projects as Provided by the Project Developers

Item	Swan Lake North	JD Pool	Black Canyon
Location	Oregon	Washington	Wyoming
Approx. static head (ft)	1,188-1,318	1,900-2,100	1,063
Energy storage (MWh)	5,280	16,500	5,550
Estimated hours of storage (hrs)	8.8	11	9.5
Estimated installed capacity (MW)	600	1,500	600
Developer Provided Estimated Capital Cost ($/kW) (See section 3.1.6 for details of HDR's Opinion of Costs)	$2,300	$1,700-$2,500	$1,500
Estimated O&M Costs (estimated as a function of capacity and annual energy. See section 3.1.6 for details)	$9,400,000	$19,100,000	$9,400,000

3.1.3.2 Swan Lake North

The current preliminary permit for the Swan Lake North Pumped Storage Project (FERC No. 13318) updates a prior preliminary permit filed by Symbiotics. The original preliminary permit application was filed in June 2010, and was granted on August 6, 2010. The draft license application was filed on December 16, 2011. A successive preliminary permit was filed in April 2012 by Symbiotics for Swan Lake LLC so that the project developer would be able to file a Final License Application before the expiration of the preliminary permit. EDF indicated that the final license application has been drafted, but revisions are pending completion of supplemental geotechnical studies and corresponding engineering revisions in the final license application.

EDF has made a number of changes to the project layout when compared with the configuration in the active preliminary permit. EDF's project is proposed to be 600 MW in capacity, a reduction from the 1000 MW project described in the preliminary permit. The size of the reservoirs was reduced to reflect the change in capacity. EDF has also revised water conveyance arrangement to reduce the overall amount of tunneling and is considering surface penstocks. The site layout as provided by EDF is shown in Figure 4.

According to EDF, the headrace inlet/outlet structure would be located at the western end of the upper reservoir. The structure would consist of two circular bellmouth intakes to control the flow of water into two surface penstocks, approximately 2,320 feet long each. The penstocks would lead to two 572 foot long drop shafts. Horizontal headrace tunnels would connect the drop shaft to the underground powerhouse. A tailrace tunnel would be located on the southeastern end of the lower reservoir to connect the powerhouse to the lower reservoir.

The powerhouse would be located at the foot of an escarpment between two scree fields. The powerhouse would contain four pump-turbine motor-generator turbine assemblies, all associated electrical and mechanical support equipment, personnel sanitary facilities, changing and meeting rooms, a control room, and transformers. This is a shift from the preliminary permit application's design which reflected a powerhouse with separate transformer galleries.

Four reversible units would be installed in the powerhouse. Each unit would have a rated generating capacity 150 MW for a total plant rating of 600 MW. The turbine operating head range is 1,188 to 1,318 feet. EDF reports that this configuration has a storage capacity of 5,280 MWh.

The upper reservoir would be contained by a 111 foot tall, 6,560 foot long compacted rockfill dam with an asphalt concrete face. The upper reservoir would have a usable storage volume of 5,837 acre-ft. This is approximately one half the size of the upper reservoir in the active preliminary permit. The lower reservoir would be impounded by a 100 feet high, 5,245 feet long dam. The resulting reservoir would have a usable storage volume of approximately 6,000 acre-ft, which is smaller than the 11,583 acre-ft reservoir in the preliminary permit.

The project site would be accessed from Highway 140 via a private road, with Swan Lake Road as a secondary access road for vehicles approaching the project area north of Highway 140. A new, permanent 24-foot-wide haul road would be constructed up the slope of Swan Lake Rim between the upper and lower reservoirs. The haul road would be approximately 3.5 miles long.

Interconnection studies have been conducted with the Transmission Agency of Northern California (TANC) under the original 1,000 MW configuration. The study concluded that only 400 MW could be interconnected without requiring additional transmission circuits, and the interconnection request was withdrawn. Another interconnection study was performed for PacifiCorp utilizing the 600 MW configuration. The project would connect to the northern segment of the 500 kV #2 Malin-Round Mountain line. It appears that 600 MW could be interconnected without additional circuits. EDF is currently preparing for an Impact Study with PacifiCorp and BPA.

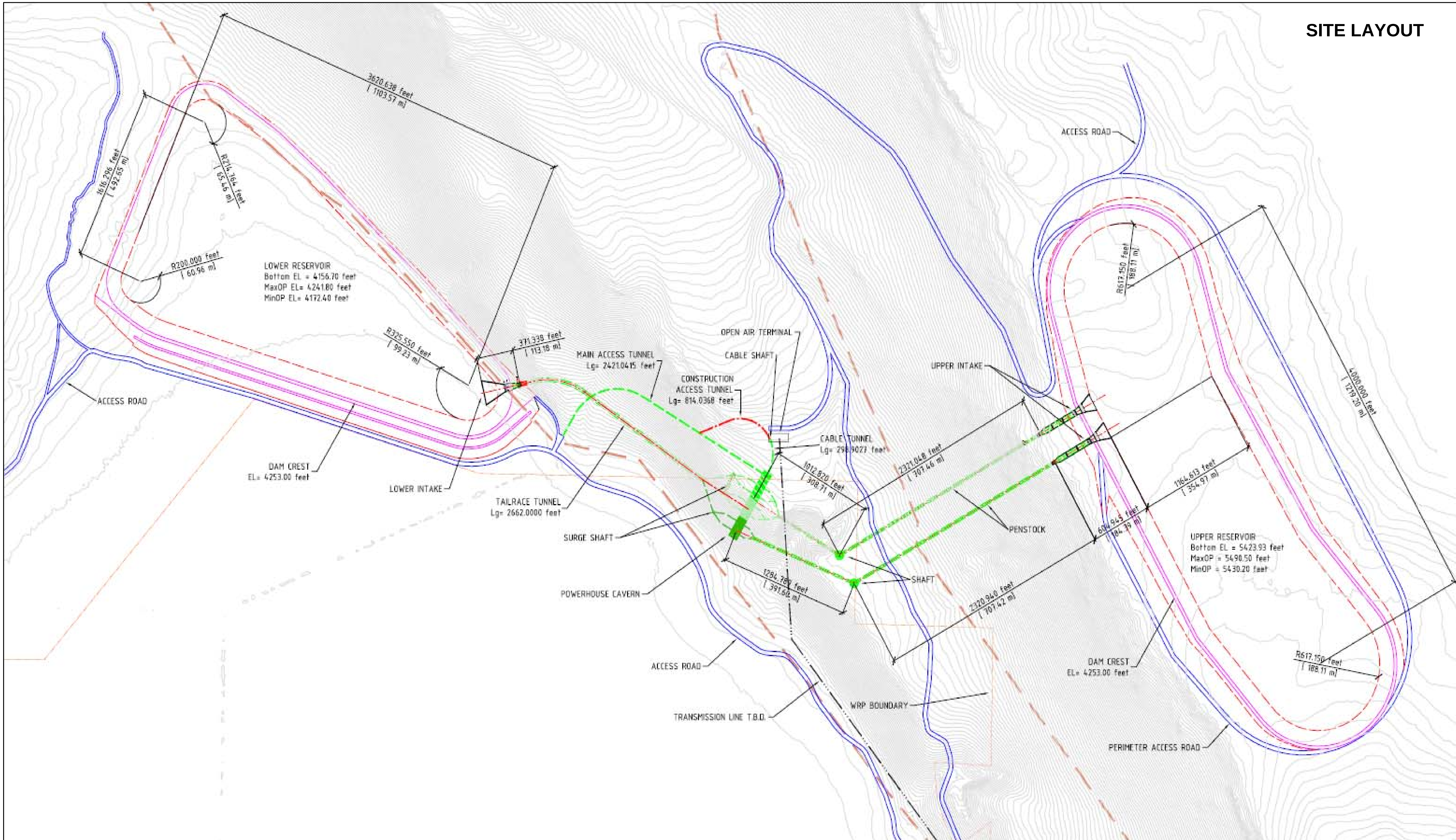
A feasibility-level geotechnical and geophysical investigation of the project site has been performed to assess the soils and facilitate ongoing permitting. The primary objective of the investigation was to evaluate the susceptibility of the soils to liquefaction under seismic loading. Additional ongoing geo-tech testing is needed to validate assumptions and further refine the powerhouse location and conveyance alignments.

EDF documented consultation with affected agencies and stakeholders. Limited resource studies have been conducted and reportedly include:

- Water resources,
- Fish and aquatic resources,
- Botanical resources,
- Wildlife resources,
- Threatened and endangered species,
- Wetlands,
- Recreation,
- Land use,
- Cultural resources, and
- Tribal resources.

In reviewing the draft license exhibits, it appears that the studies have been performed using existing data and consultation. HDR anticipates that field studies would be the next step to further advance the project.

EDF indicated that they have developed a Class 4 cost estimate in accordance with the Association for the Advancement of Cost Engineering (AACE). Refer to Appendix B.7 for the AACE cost estimating guidelines. The estimate for the project including direct costs, engineering, construction management, licensing costs is $1.4 billion. This is approximately $2,300 per kW.



SITE LAYOUT
3620.638 feet
[1103.57 m]
1616.296 feet
[492.65 m]
R214.764 feet
[65.46 m]
R200.000 feet
[60.96 m]
LOWER RESERVOIR
Bottom EL = 4156.70 feet
MaxOP EL= 4241.80 feet
MinOP EL= 4172.40 feet
R325.550 feet
[99.23 m]
371.339 feet
[113.18 m]
MAIN ACCESS TUNNEL
Lg= 2421.0415 feet
OPEN AIR TERMINAL
CABLE SHAFT
CONSTRUCTION
ACCESS TUNNEL
Lg= 814.0368 feet
CABLE TUNNEL
Lg= 298.9027 feet
ACCESS ROAD
DAM CREST
EL= 4253.00 feet
LOWER INTAKE
TAILRACE TUNNEL
Lg= 2662.0000 feet
SURGE SHAFT
POWERHOUSE CAVERN
ACCESS ROAD
TRANSMISSION LINE T.B.D.
WRP BOUNDARY
1012.820 feet
[308.71 m]
1284.787 feet
[391.60 m]
2321.048 feet
[707.46 m]
2320.940 feet
[707.42 m]
UPPER INTAKE
PENSTOCK
SHAFT
604.945 feet
[184.39 m]
1164.613 feet
[354.97 m]
ACCESS ROAD
R617.150 feet
[188.11 m]
4000.000 feet
[1219.20 m]
UPPER RESERVOIR
Bottom EL = 5423.93 feet
MaxOP = 5490.50 feet
MinOP = 5430.20 feet
DAM CREST
EL= 4253.00 feet
R617.150 feet
[188.11 m]
PERIMETER ACCESS ROAD

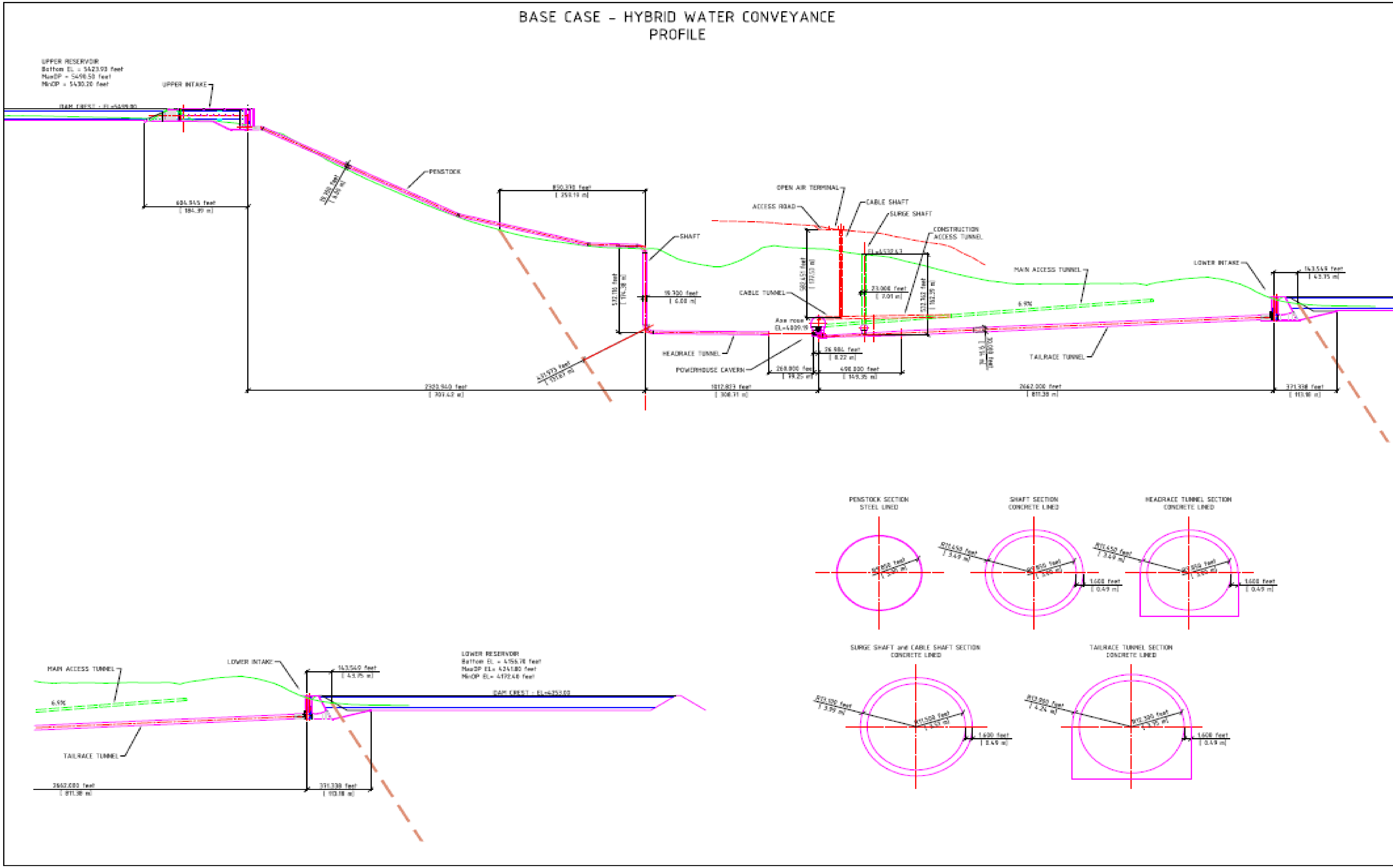


Figure 4 - Swan Lake North Site Layout and Profile (Swan Lake North Pre-Application Document)

HDR OPINION

The Swan Lake North pumped storage project has been advanced by EDF subsequent to acquiring 100 percent ownership of the project LLC. Having the ground water rights issues resolved to support initial fill is significant and the initial geotechnical investigations are a step in the right direction to advance the engineering elements.

The design decision to use surface penstocks should be carefully considered. While limiting tunnel lengths may potentially reduce tunneling capital costs, it is HDR's experience that surface penstocks are typically more costly to construct where construction access is difficult or foundation conditions may be unstable.

It should be noted that EDF France's involvement is a major factor in the potential successful execution of the project given their extensive pumped storage design and execution resume around the globe. However in the absence of any substantive off-taker agreements, the Swan Lake North project has not progressed beyond the conceptual engineering stage; and firm estimates of cost, or project fatal flaws, have not been completed.

3.1.3.3 JD Pool

The original preliminary permit application for the JD Pool Pumped Storage Project (FERC No. 13333) in the Columbia Gorge in southern Washington was filed by the Klickitat Public Utility District and Symbiotics LLC on November 20, 2008, and formed the basis of HDR's 2011 energy storage technology assessment report. A successive application was filed by Klickitat on April 30, 2012, and the information included in the revised application forms the basis of HDR's review of the project presented below.

Klickitat provided a response to the RFI that generally replicates the information in the active preliminary permit application. The JD Pool project layout appears to have been modified such that both the upper and lower reservoirs have been shifted slightly to the west. This results in a potential increase of approximately 200 to 400 feet in total head to a maximum head of approximately 2000 feet. This new upper and lower reservoir alignment is achieved via the construction of much larger reservoir embankments in terms of volume of fill material; however, engineering studies documenting the technical feasibility of the change in reservoir location do not appear to have been conducted. According to Klickitat's response to the RFI, the dam configuration, water conveyance layout, and equipment configuration have not been further developed. The project configuration below was extracted from the active preliminary permit application.

All project features associated with JD Pool would be new with the exception of the existing pumping station, associated conveyance piping and equipment from the closed aluminum smelter, which is partially located on Federal lands near the John Day Pool. A new 24 foot diameter, 9,188 foot long steel penstock is proposed, connecting the upper reservoir to the underground powerhouse. The powerhouse would consist of 5 units, 300 MW each for a proposed capacity of 1,500 MW. The turbines would be rated at 2,100 CFS and would have an operating range between 1,900 feet and 2,100 feet of head. There are two reservoirs associated with the project. The upper reservoir would require a new earth embankment with a clay core. The dam would be 270 feet high and 8,610 feet long. The upper reservoir would have a storage capacity of 14,010 acre-ft, a surface area of 114 acres, and a normal surface, elevation of 2,710 MSL. The new lower reservoir would also require an earth embankment with a clay core. The dam would be 295 feet high and 5,870 feet long. The lower reservoir reportedly would have a storage capacity of 21,440 ac-ft (approximately 50% greater than the upper reservoir), a surface area of 110 acres, and a normal surface elevation of 705 MSL.

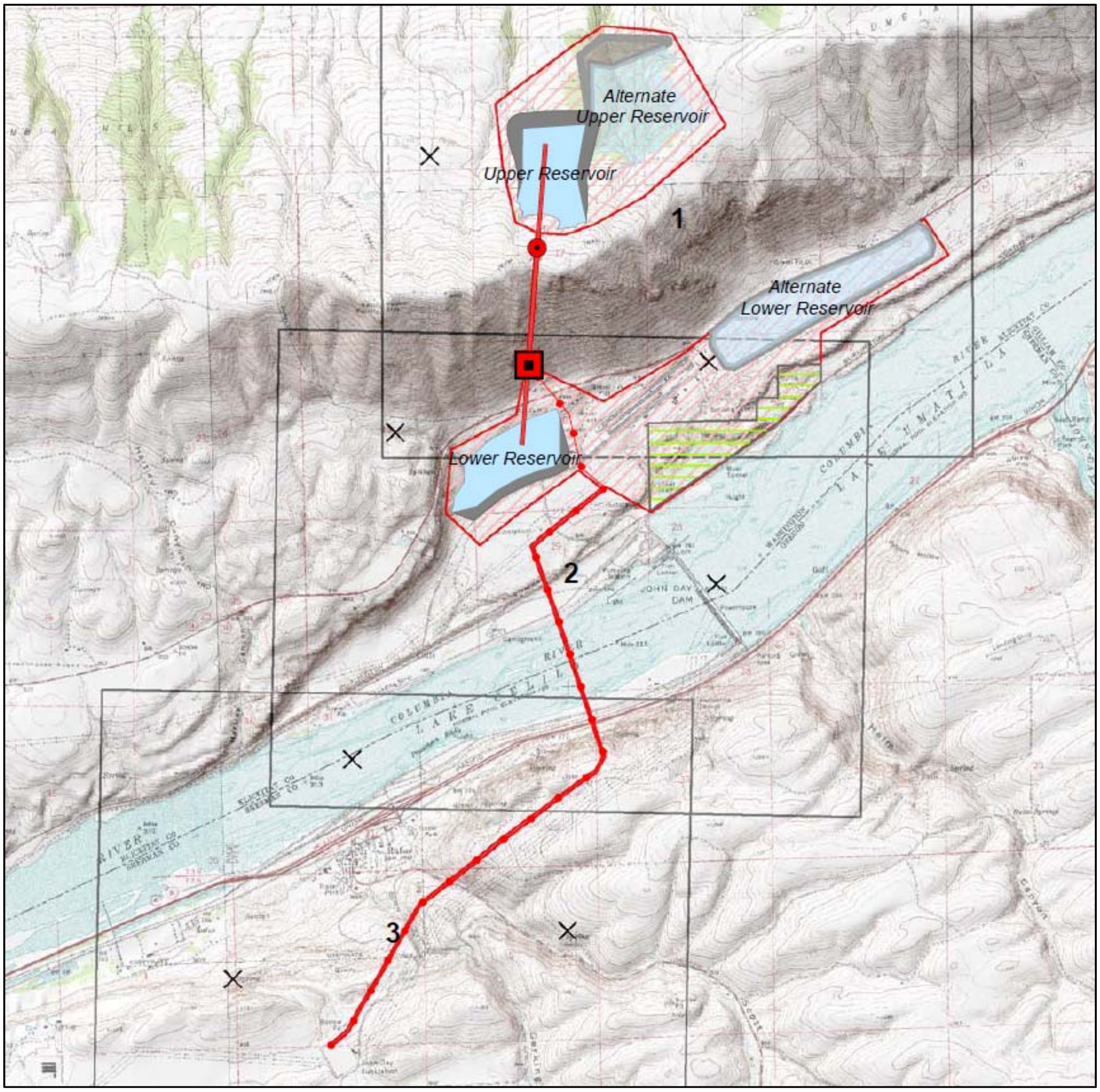


Figure 5 - JD Pool Project Layout (JD Pool Preliminary License Application)

According to the preliminary permit application, the project would interconnect with BPA's 500kV John Day substation, approximately 5 miles away from the project site via a new 500 kV line. According to Klickitat's RFI response, the project is also 8 miles from an alternate DC intertie. This project would be part of the Western Electricity Coordination Council market.

According to Klickitat, this project is still in the early stages of development, and no detailed engineering or environmental studies have taken place. Klickitat indicated that they own the water to serve the project through the Washington State Department of Ecology, and the water withdrawal facilities are part of the existing infrastructure from the former aluminum smelter located at the site. Klickitat did not provide a cost estimate at this stage of development. In 2005, HDR was involved in a reconnaissance level study and AACE Class 5 cost opinion for the Goldendale Pumped Storage Project, an early version of JD Pool.

At that time, HDR developed a cost opinion of approximately $2.8 billion. Assuming a 3% escalation per year, cost is approximately $3.7 billion 2014 USD, or approximately $ 2,500 USD per kW.

HDR OPINION

HDR believes that the JD Pool pumped storage site is one of the premier sites in the Pacific Northwest for development. It is in the middle of BPA's robust high voltage transmission corridor, it can be developed in an environmentally benign manner, and the associated topography supports a high energy density design.

The project status at this time, however, is still at the conceptual stage with no advancements in engineering trade-off studies or environmental and resource assessments. An example of a project disconnect is the disparity between the storage volumes of the upper and lower reservoir as indicated in the active preliminary permit; ideally they would be equal in a closed loop system. There have not been any field studies to date, and Klickitat indicated they are actively searching for a development partner. The lack of progress on the regulatory requirements does put the project developer at risk for being able to maintain the active preliminary permit.

3.1.3.4 Black Canyon

The preliminary permit application for the Black Canyon Pumped Storage Project (FERC No. P-14087) was prepared by Gridflex Energy, LLC and was filed by Black Canyon Hydro, LLC on January 25, 2011. The application currently shows four alternatives for development. See Figure 4 for the project layout. Two new upper reservoirs, the East Reservoir and the North Reservoir, could be connected to one of two existing lower reservoirs, the Seminoe Reservoir and the Kortes Reservoir. The developer may select one or a combination of the alternatives.

In their response to the RFI, Gridflex indicated that their preferred alternative at this time connects the East Reservoir and the existing Seminoe Reservoir. The other three configurations, however, are still under consideration. The project description below was extracted from the active preliminary permit application. Based upon the RFI response, it appears that Gridflex revised the project sizing for Black Canyon from the preliminary permit application. In the FERC filing, the project is described as a 400 MW plant with reportedly an additional 100 MW of pumping capacity. In the RFI submittal, Gridflex presents a 600 MW project for the same preferred alternative with no additional pumping capacity. The change appears to be in the unit sizing and not the configuration of the dams and reservoirs.

The East Reservoir would be connected to the Seminoe Reservoir by approximately 6,800 feet of conduit. Maximum hydraulic head for the project would be 1,063 feet. A 20.4 ft diameter low pressure tunnel would extend for 800 ft and connect to a 5,800 ft long pressure shaft to the powerhouse. A 200 ft long section of tailrace tunnel would connect the powerhouse to the lower reservoir. The penstock configuration was not addressed in Gridflex's response to the RFI.

The powerhouse would be located approximately 200 feet east of the Seminoe Reservoir. Gridflex indicated that an underground powerhouse is preferred in the RFI submittal. HDR concurs with this underground cavern concept where the project is planning to utilize an existing lower reservoir due to constructability. However, in HDR's opinion, the powerhouse is proposed to be located very close to the existing lower reservoir and appears to be a shoreline powerhouse configuration, and the constructability of the powerhouse should be carefully evaluated.

Also the sizing of the pump-turbine generator-motor units differs between the RFI and the preliminary permit application. According to the preliminary application, three 133 MW adjustable-speed reversible pump-turbines would be utilized for 400 MW of generating capacity. The units would be capable of an additional 100 MW of additional pumping capacity. In Gridflex's RFI response, a 600 MW project is described for the same East Reservoir-Seminoe alternative without any additional capacity during pumping operation. In their submittal, the developer reported that the units would provide 100-200 MW each in the pump mode and 50-200 MW in the generating mode, but HDR's experience with pump-turbines indicates that this operating range is not realistic, including the most advanced variable speed technology.

The proposed East upper reservoir would consist of a new 50 ft ring dam and would be 8,724 ft long and impound a 9,700 acre-ft reservoir. The lower reservoir for this project would be the existing Seminoe Reservoir. The reservoir is 1,016,717 acre-ft and is impounded by Seminoe dam, an existing 295 ft high concrete arch dam.

The project would interconnect with the Western Area Power Administration (WAPA) Miracle Mile-Cheyenne line near the Seminoe Dam. This line runs through the Medicine Bow area, where energy from the project would be transferred to one of several planned terminals for new transmission facilities. These include the Gateway West line (PacifiCorp) via the Aeolus substation, the Zephyr line, the TransWest Express, and the Overland. The interconnection point would be adjacent to the project powerhouse.

The project would utilize the water resources of the North Platte River as stored and transferred through the Seminoe and Kortes Reservoirs.

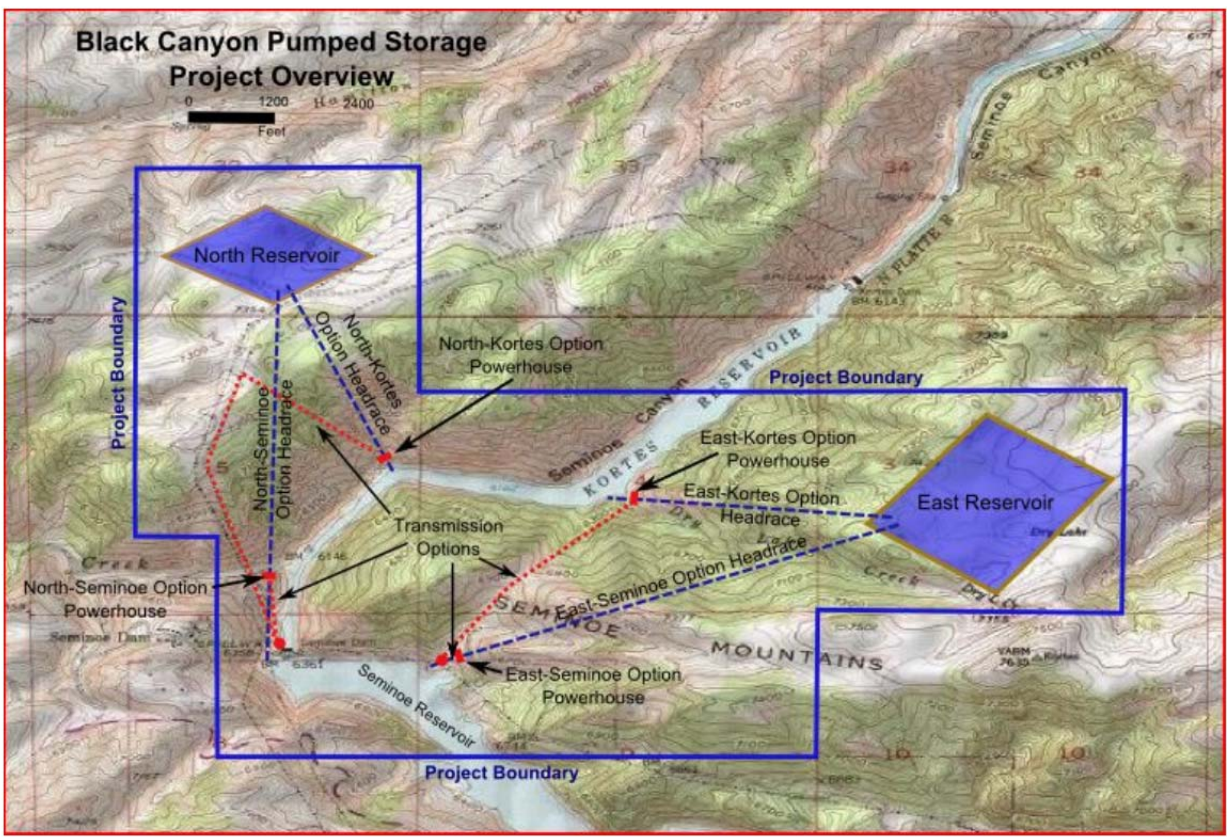


Figure 6 - Black Canyon Layout (Black Canyon Preliminary Permit Application)

The developer has indicated that they intend to purchase water rights from adjacent land owners who are existing water rights holders. In HDR's experience, the acquisition of water rights can be a lengthy and difficult process depending upon the geographic region and stakeholder interests. Both upper reservoirs would be located on land managed by the Bureau of Land Management (BLM), as would a part of the conduit path. The existing Kortes and Seminoe Reservoirs and dams are owned and operated by Reclamation. Study plans have not been developed yet, but Gridflex reported that they have consulted with both the BLM and Reclamation.

Gridflex indicated that their project an AACE Class 4 or 5 cost estimate of approximately $883 million dollars, which is about $1,500 per kW. This appears to be low given the stage of development of the project. In HDR's opinion, the level of engineering demonstrated by Gridflex's response to the RFI does not fully reflect the potential construction costs of a new upper reservoir, powerhouse, prime mover elements and other extensive balance of plant systems, plus the water conveyance system. The engineering and licensing also appears to be low, at only 7% of the project construction cost. Gridflex included construction management in the direct project cost, but in HDR's experience this typically represents an additional cost and should be listed separately. For this level of project development, HDR would expect project contingency to be in excess of 30% for a Class 4 or 5 cost estimate rather than the 20% reflected in Gridflex's response. Gridflex indicated that a renewable integration study has been conducted with Wyoming wind data, but the report was not attached to the RFI response. The developer indicated that the project could be operational as early as 2020, but from the level of engineering development and licensing progress, this date does not appear to be achievable to HDR.

HDR OPINION

The Black Canyon project is the least advanced of the three pumped storage projects investigated for this report, and significant additional feasibility work needs to be done to determine if the project is viable. It does not appear that any engineering alternatives analyses or preliminary desktop geological assessments have been completed to further refine the site or to identify potential geological fatal flaws. The concept of a shoreline powerhouse next to an existing lower reservoir should be refined to demonstrate that required unit submergence can be achieved. The reported unit operating parameters also require further clarification.

The constructability of a shoreline powerhouse near an existing reservoir should be carefully considered. Pump-turbines typically require submergence, or setting of the centerline of the pump-turbine approximately 10% of the gross head below the minimum tailwater elevation. This equates to approximately 100 feet for Black Canyon just for unit submergence alone. The resulting very deep excavation required near an existing body of water would potentially create significant water management issues during construction.

The reported costs appear to be low based upon HDR's industry experience and the current market prices for the prime movers and the extensive balance of plant systems. The project timeline for construction and commissioning is also unrealistic based upon HDR's industry experience, and do not appear to be based on advanced engineering or environmental studies. These studies would include analysis of existing infrastructure, site specific geology, transmission interconnect studies, resource (e.g. botanical, aquatic, land use, cultural) studies, and other factors critical for determining the technical and economic feasibility of a new pumped storage project.

3.1.4 Operating Characteristics

The pumped storage projects in development are driven by the opportunity to capitalize on the anticipated markets for energy arbitrage and ancillary services. Energy arbitrage refers to the practice of utilizing electric energy during the lower priced hours of excess energy to pump water from a lower reservoir into the upper reservoir. The water is then stored in the upper reservoir for potential use. When energy prices are higher, water is released from the upper reservoir through the turbines, and electricity is generated and sold at these higher prices. Energy arbitrage results in higher net income when the difference between on-peak and off-peak prices is greatest.

The projects would also provide ancillary services in both operating modes. FERC has defined ancillary services as, "those services necessary to support the transmission of electric power from seller to the purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system" (FERC 1995). As described above, variable-speed units are more suitable for providing ancillary services than single-speed units, particularly frequency regulation. The projects could provide the following services:

- **Spinning Reserves -** Reserve capacity provided by generating resources that are running (i.e., "spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. Spinning Reserves are needed to maintain system frequency stability during periods of energy imbalance resulting from unanticipated variations in load, or variable energy supply. Reserves are also required to respond to emergency operating conditions created by forced outages of scheduled units.
- **Non-Spinning Reserves -** Generally, reserve capacity provided by generating resources that are available but not rotating. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Non-Spinning Reserves are needed to maintain system frequency stability during emergency conditions.
- **Regulation -** Reserve capacity provided by generating resources that are running and synchronized with the grid, so that the operating levels can be increased (incremented) or decreased (decremented) instantly through Automatic Generation Control to allow continuous balance between generating resources and demand.

3.1.5 Regulatory Overview

Some of the most important aspects in the evaluation of siting and development of a potential pumped storage project are the environmental and regulatory factors. All pumped storage project development by non-federal entities requires the project developer to go through the FERC licensing process, which is expected to take approximately three to five years. For some projects, the potential issues associated with project development may be fatal flaws, for others the mitigation measures are minimal and manageable. Many of the most promising new pumped-storage sites identified by the hydropower industry are closed-loop pumped-storage. It is generally accepted within the industry that a Greenfield closed loop pumped storage project could be licensed in less than five years as many of the environmental and resource issues can be relatively easily mitigated.

Environmental and resource concerns may include fisheries issues (e.g. entrainment or, impingement), site clearing and construction impacts, impacts to recreation, and land use concerns. For closed-loop systems, there is no water discharged from the station into the main-stem river as a result of routine unit operations and the historical concerns regarding fish entrainment and impingement at conventional hydropower stations is thereby avoided. With respect to site clearing and other land use concerns new large pumped-storage plants typically consist of an underground powerhouse and, thus, mitigate to a large degree the overall footprint of the station. But these hydroelectric projects generally require construction of roads, main or saddle dams, spillways, transmission lines, and other aspects that may alter the existing landscape.

3.1.6 Capital, Operating, and Maintenance Cost Data

3.1.6.1 Capital Cost

The following discussion is applicable to pumped storage projects with which HDR is familiar, and does not necessarily reflect the three projects discussed above. Nonetheless, the three projects appear to fall in the range of reasonable cost for similar pumped storage projects. The direct cost to construct a pumped storage facility is highly dependent on a number of physical site factors, including but not limited to topography, geology, regulatory constraints, environmental resources, project size, existing infrastructure, technology and equipment selection, capacity, active storage, operational objectives, etc. According to the HDR database, one could expect the direct cost of a pumped storage facility utilizing single speed unit technology to be in the order of $1,700 to $2,500 per kW. The direct cost for a facility utilizing variable speed unit technology is expected to be approximately 10 to 20 percent greater than that of a facility utilizing single speed technology. Direct costs include:

- Cost of materials
- Construction of project features (tunnels, caverns, dams, roads, etc.)
- Equipment
- Labor for construction of structures
- Supply and installation of permanent equipment
- Procurement of water rights for reservoir spill and make up water

Indirect costs generally run between 15 and 30 percent of direct costs and are largely dependent on configuration, environmental/regulatory, and ownership complexities and include cost such as:

- Preliminary engineering and studies (planning studies, environmental impact studies, investigations),
- License and permit applications and processing,
- Detailed engineering and studies,
- Construction management, quality assurance, and administration,
- Bonds, insurances, taxes, and corporate overheads.

HDR has summarized the cost opinions for the three selected pumped storage projects.

For Swan Lake North, EDF provided a cost estimate of $2,300 per kW. In 2012, HDR prepared a Class 4 cost opinion at the request Symbiotics for Swan Lake North. HDR's cost opinion at the time was between $2 billion and $2.3 billion. When HDR's cost opinion is escalated using a rate of 3% per year, it appears to be consistent with EDF's response to the RFI.

HDR conducted a reconnaissance level study and a Class 5 cost opinion for the Goldendale Pumped Storage Project, which was an early version of the current JD Pool Pumped Storage Project. HDR's cost opinion was on the order of $2.8 billion in 2005. The cost estimate was escalated at a rate of 3% per year, which yields $3.7 billion in 2014 USD. Klickitat PUD did not provide a cost estimate in their response to the RFI. In the Preliminary Permit Application, however, a cost opinion of $2 billion to $2.5 billion was provided. The cost opinion was for a 1,000 to 1,200 MW project, which equates to $1,700 to $2,500 per kW. It appears that Klickitat PUD's cost opinion is budgetary in nature, and HDR could not verify that the cost opinion conformed to the AACE guidelines as there was no breakdown provided. HDR expects that the total project cost for JD Pool could be on the order of $2,000 to $2,500 per kW.

Based on cost opinions developed for similar pumped storage projects, HDR expects that the construction cost for Black Canyon could be on the order of $2,000 per kW. The $1,500 per kW reported by Gridflex appears to low to cover both direct and indirect costs. It is also low when compared to cost opinions for other pumped storage projects.

For Swan Lake North and JD Pool, the developer's cost estimate seems reasonable given the early stage of development for each project. The cost estimate provided by Gridflex for Black Canyon appears low. This comparison is summarized in Table 5 below.

Table 5 - Comparison of Cost Opinions

Item	Swan Lake North	JD Pool	Black Canyon
HDR Cost Opinion ($/kW)	$2,100 - $2,400	$2,500	$2,000 - $2,300
Developer Estimated Capital Cost ($/kW)	$2,300	$1,700 - $2,500	$1,500

3.1.6.2 Annual Operation and Maintenance (O&M) Costs

Operation, maintenance, and outage costs vary from site to site dependent on specific site conditions, the number of units, and overall operation of the project. For the purposes of this evaluation, a generic four unit, 1,000 MW underground powerhouse has been assumed. As seen from the project examples above, this is a common arrangement selected for a pumped storage project.

Previous Electric Power Research Institute (EPRI) studies provide the following equation for estimating the annual operations and maintenance (O&M) costs for a pumped storage project in 1987 dollars:

$$\text{O\&M Costs (\$/yr)} = 34{,}730 \times C^{0.32} \times E^{0.33}$$

Where: C = Plant Capacity, MW

E = Annual Energy, GWh

This methodology is considered valid and an escalation multiplier of 2.06 is recommended to escalate 1987 costs to 2014. In addition, the following additional annual costs are recommended:

- Annual general and administration expenses in the order of 35% of site specific annual O&M costs, and
- Annual insurance expenses equal to approximately 0.1% of the plant investment costs, or capital cost.

For a 1,000 MW pumped storage project costing $2,500 per kW, generating 6 hours per day 365 days per year, and annual energy production of 2,190 GWh. The calculated annual O&M, administrative, and insurance costs are approximately $13.6 million in 2014 USD.

3.1.6.3 Bi-Annual Outage Costs

In addition to annual O&M costs, it is recommended within the industry that bi-annual outages be conducted. Again, the frequency of the inspections and the subsequent repairs following inspections can vary depending upon how the units are operated, how many hours per year the units will be on-line, how much time has elapsed since the last inspection/repair cycle, the technical correctness of the hydraulic design for site specific parameters, and water quality issues.

Conservatively, in a four unit, 1,000 MW powerhouse, two units would be taken out of service for approximately a three week outage every two years. For units of this size, $262,000 for two units should be budgeted.

3.1.6.4 Major Maintenance Costs

It is recommended within the industry that a pump-turbine overhaul accompanied by a generator rewind be scheduled at year 20. The typical outage duration is approximately six to eight months. Pumped storage units are typically operated twice as many hours or more per year than conventional generating units if utilized to full potential. This increased cycling duty also dramatically increases the degradation of the generator components. This increased duty results in the requirement to perform major maintenance on a more frequent basis.

The work included and the frequency of this outage can vary based on project head, project operation, and regular maintenance cycles. Overhauls typically include restorations of all bushings and bearings in the wicket gate operating mechanism, replacement of wicket gate end seals, rehabilitation of the wicket gates including non destructive examination (NDE) of high-stress areas, rehabilitation of the servomotors, replacement of the runner seals, NDE of the head cover, restoration of the shaft sleeves and seals, and rehabilitation of the pump-turbine bearing. The end result is restoring the pump-turbine to like-new running condition. Pump-turbine inlet isolation valves will likely require refurbishment of the valve seats and seals. The service life of a generator-motor is generally dependent upon the condition of the insulation in the stator and rotor. The need for re-insulation of the stator and rotor, typical of a salient pole design, can vary from 20 to 40 years depending upon the duty cycle and insulating materials utilized.

The costs for these modifications depend on many factors. Due to the complexity of the scope, an estimate must be developed for each installation. For the purposes of this study, approximately $6.28 million was estimated for reversible Francis units at year 20.

3.2 Batteries

3.2.1 Battery Energy Storage Technology Description

Battery energy storage systems are functionally electrochemical energy storage devices that convert energy between electrical and chemical states. Electrode plates consisting of chemically-reactive materials are situated in an electrolyte which allows the directional movement of ions within the battery. Negative electrodes (cathodes) give up electrons (through electrochemical oxidation) that flow through the electric load connected to the battery, and finally return to the positive electrodes (anodes) for electrochemical reduction. This basic direct current (DC) can be inverted into the desired alternating current (AC) frequency and voltage.

Certain battery technologies have significant exposure in various markets including telecom, end-user appliance, automotive, and on a larger scale, utility applications. Batteries are becoming one of the faster-growing areas among utility energy storage technologies in frequency regulation applications, renewable energy systems integration, and in remote areas and confined grid systems where geographical constraints do not fit well with the application of hydroelectric storage or CAES. Batteries have surpassed CAES in stored energy capacity to total an estimated 556 MW, or 0.36% of global storage capacity in 2012.

Electric utility companies as well as large commercial and industrial facilities typically utilize battery systems to provide an uninterruptible supply of electricity to power a load (e.g. substation, data center) and to start backup power systems. In the residential and small commercial sector, conventional use for battery systems includes serving as backup power during power outages.

Common types of commercialized rechargeable and stationary battery technologies include, but are not limited to, the following:

- Sodium sulfur (NAS)
- Dry Cell
- Advanced lead acid (Pb-acid)
- Family of lithium ion chemistries (Li-ion)
- Flow - Vanadium redox (VRB)
- Flow - Zinc bromide (ZnBr)

In physical form, these battery types are modular and enclosed in a sealed container, with the exception of flow batteries. Flow batteries' distinguishing characteristic is their independent and isolated power and energy components, comprised of cell "stacks" and tanks to hold the electrolyte. They operate by flowing the electrolyte through cell stacks to generate electrical current.

3.2.2 Manufacturers and Commercial Maturity of Technology

All of these batteries types have the technical potential for penetration into specific utility markets and applications. The remainder of this section discusses battery technologies that are considered suitable for specific utility applications. Due to the limited scope of this study, only information collected from manufacturers representing select battery technology is presented. The six manufacturers included in this study, based on their deployment on utility systems, are:

- Lithium ion (Li-ion) - A123 Systems, Inc. (A123)

- Sodium sulfur (NAS) – NGK Insulators, Ltd. (NGK)
- Vanadium redox battery (VRB) – Prudent Energy Corporation (Prudent)
- PowerCells^{TM} – Xtreme Power, Inc. (Xtreme)
- Zinc bromine (ZnBr) – Premium Power Corporation (Premium)
- Advanced Lead Acid (Pb-Acid) – Ecoult Energy Storage Solutions (Ecoult)

3.2.2.1 Lithium Ion (Li-ion) – A123 Systems, Inc. (A123)

Li-ion and lithium polymer-type batteries have been widely used in end-user appliances (e.g. consumer electronics) and have become the de facto energy storage system in the electric vehicle industry (e.g. hybrids and electric vehicles). Within the battery itself, lithiated metal oxides make up the cathode and carbon (graphite) make up the anode. Lithium salts work as the electrolyte. In a charged battery, lithium atoms in the cathode become ions and deposits in the anode. An example chemical balance can be characterized as:

$$\text{LixC + Li1-xCoO2} \leftrightarrow \text{LiCoO2 + C}$$

Li-ion batteries are known for having high energy density and low internal resistance, making efficiencies (defined as round trip AC out to AC in) upwards of 90% possible. This technology is very attractive for mobile applications and potentially utility power quality applications. An external heating or cooling source may be required depending on ambient conditions and system operation to maintain their operating temperature range of 20 to 30 ^{o}C. A123 projects are focused on renewables firming and ramp management, frequency regulation, and T&D and substation support. Projects in their portfolio have less than 1 hour of energy storage with the exception of a 4-hr wind integration plant. Since 2009, seven projects have been installed in the US with capacity of 69 MW / 47.5 MWh. The largest projects include 20 MW / 5 MWh in Johnson City, NY and 8 MW / 32 MWh in Tehachapi, CA. Currently under development (Figure 8) is a 32 MW / 8MWh system in Oro Mountain, WV. This technology is classified as commercial because it has been implemented in the utility markets.

Figure 7 - A123 Li-ion Cells

Figure 8 - Renewable Integration Deployment in West Virginia

3.2.2.2 Sodium Sulfur (NaS) – NGK Insulators, Ltd. (NGK)

In its simplest form, a NaS battery consists of molten sulfur positive electrode and molten sodium negative electrode, separated by a solid beta-alumina ceramic electrolyte (Figure 9). In the discharge cycle, the positive sodium ions pass through the electrolyte and combine with sulfur to form sodium polysulfides. During the charge cycle, the sodium polysulfides in the anode start to ionize to allow sodium formation in electrolyte according to:

$$2Na + xS \leftrightarrow Na_2S_x$$

Among the prevalent technologies, NaS batteries have high energy densities that are only lower than that of Li-ion. The efficiency of NaS varies somewhat dependent on duty cycle due to the parasitic load of maintaining the batteries at the higher operating temperature of 330degrees Celsius. However, the battery modules are packaged with sufficient insulation to maintain the battery in its hot operating state for periods of several days in a "standby" mode. NGK projects are focused on island / peak shaving applications, and solar integration. Projects in their portfolio are multiple-hour systems. The first project was 0.5 MW for a TEPCO Kawasaki substation in 1995. Installations now include over 120 international projects with capacity of 190 MW and 1,300 MWh. The largest project is 12 MW / 86.4 MWh at a Honda facility Japan, installed in 2008 (Figure 10). As of 2010, six projects in the US with 14.75 MW / 73.2 MWh have been installed, with the largest project being 4 MW / 24 MWh in Presidio, TX (2010). Five projects totaling 7.9 MW / 23.2 MWh are planned throughout the US. This technology is mature, given its large number of installations, especially in Japan, and the many years of research and development targeted for utility energy storage applications.

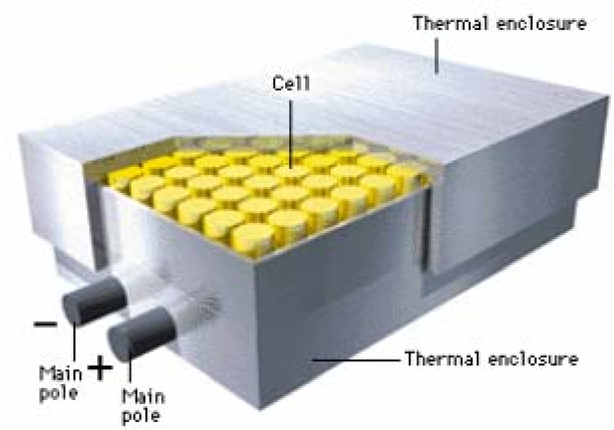


Figure 9 - NAS Cell Module

Figure 10 - NGK NAS 8 MW (Japan)

3.2.2.3 Vanadium Redox Battery (VRB) – Prudent Energy Corporation (Prudent)

VRB systems use electrodes to generate currents through flowing electrolytes. The size and shape of the electrodes govern power density, whereas the amount of electrolyte governs the energy capacity of the system. The cell stacks comprise of two compartments separated by an ion exchange membrane. Two separate streams of electrolyte flow in and out of each cell with ion or proton exchange through the membrane and electron exchange through the external circuit. Ionic equations at the electrodes can be characterized as follows:

$$\text{Anode: } V^{5+} + e^{-} \leftrightarrow V^{4+}$$

$$\text{Cathode: } V^{2+} \leftrightarrow V^{3+} + e^{-}$$

VRB systems are recognized for their long service life as well as their ability to provide system sizing flexibility in terms of power and energy. Representative images of VRB technology is shown in Figure 11 and Figure 12. VRB efficiency tends to be in the range of 70-75%. The separation membrane prevents the mix of electrolyte flow, making recycling possible. Prudent projects are focused on solar and wind integration, and island / peak shaving. Projects in their portfolio are multiple-hour systems. The first US project utilizing VRBs was Rattlesnake #22 with PacifiCorp in Castle Valley, UT with 0.250 MW / 2 MWh installed in 2004. The VRBs were installed in order to increase capacity and reliability of a 25kV feeder without any major environmental impacts. Additional information is available in Appendix C. In 2009, a 0.6 MW / 3.6 MWh system was installed at Gills Onion plant, CA. Two other projects are in development in CA, with combined nameplate capacity of 2.2 MW. This battery technology is classified to be in its nascent commercialization stage as there has been only a handful of utility-scale implementations, although the technology itself has been in development for 20 years.

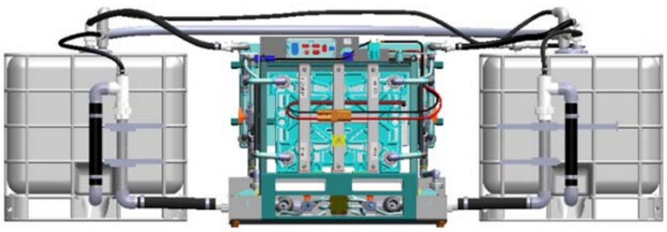


Figure 11 - VRB Cell Stack and Electrolyte Tanks

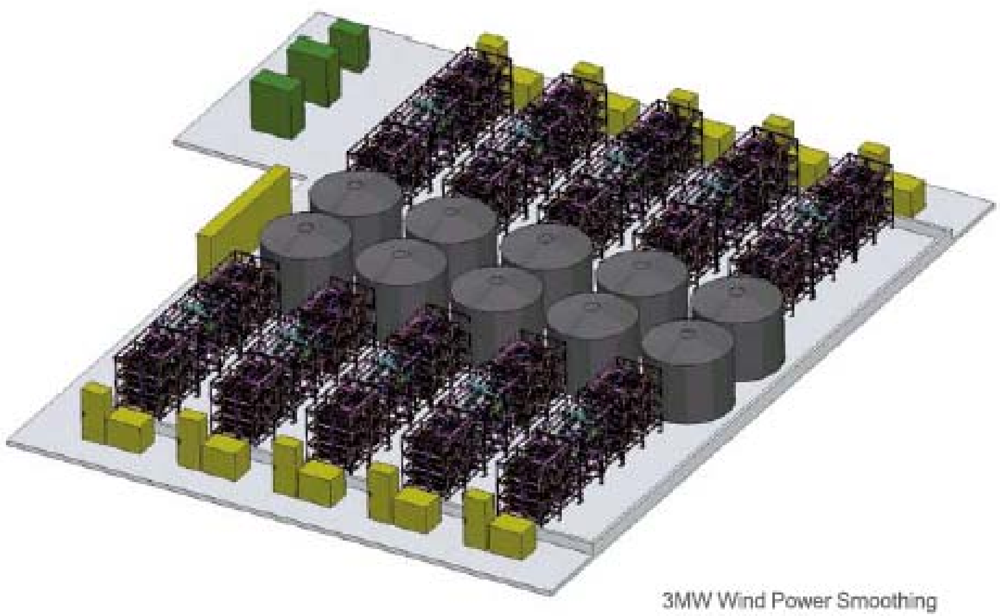


Figure 12 - Standard VRB Plant Design 3 MW

3.2.2.4 Dry Cell – Xtreme Power, Inc. (Xtreme)

Xtreme Power's PowerCellsTM were first developed over two decades ago and bears the signature characteristic of having one cell store 1 kWh worth of energy at ultra-low internal impedance. The cells were developed to maximize nano-scale chemical reactions by providing electrode plates with large surface areas. Representative images of Dry Cell technology is shown in Figure 13 and Figure 14.

These cells are solid state batteries developed from dry cell technology. Dry cells have been recognized in the industry for its high energy density and capacity as well as quick recharge times. Similar to the li-ion technology, dry cells have found success in the hybrid vehicle market and are considered to be a commercial technology in the utility industry.

Xtreme works with wind and solar integration and offers peak shaving / load leveling. Projects in their portfolio range from sub-hourly to multiple-hour systems. The first installation of 0.5 MW / 0.1 MWh was a test facility in Antartica for microgrid peak shaving completed in 2006. A 1.5 MW / 1 MWh test facility was installed in Maui, HI for renewable integration in 2009. Today, Xtreme has over 78 MW of capacity installed, over 25,000 MWh charged and discharged, and has completed renewable integration projects for Kaheawa Wind Power (Hawaii) on the scale of 10 MW with a 45 minute duration.

Figure 13 - PowerCellTM Stacks with PCS

Figure 14 - DPR15-100C Container

3.2.2.5 Zinc Bromine (ZnBr) – Premium Power Corporation (Premium)

The fundamental of energy conversion for ZnBr batteries is the same as that of VRBs. Two separate streams of electrolyte flow in and out of each cell compartment separated by an ion exchange membrane. Ionic equations at the electrodes can be characterized as follows:

$$\text{Anode: } Br_2 + 2e^- \leftrightarrow 2Br$$

$$\text{Cathode: } Zn \leftrightarrow Zn^{2+} + 2e^-$$

Like VRBs, ZnBr batteries are also recognized for their long service life and flexible system sizing based on power and energy needs. The separation membrane prevents the mix of electrolyte flow, making recycling possible. ZnBr efficiency is in the 60% range. Premium is focused on power quality, island / UPS applications, and on peak shaving / load leveling projects. Projects in their portfolio are multiple-hour systems. To date, 6.9 MW / 17.2 MWh has been installed in the US. Five recent projects, two in CA and three in MA, have been installed or are under development, rated at 0.5 MW / 3 MWh each. Like the VRB systems, ZnBr battery technology is considered in its early stages of commercialization. At the time of writing, there was no publicly available information on any of its electricity storage plants; the number and size of projects installed to date were provided by Premium. Figure 15 illustrates Premium's standard cell stack. Figure 16 shows Premium's TransFlow2000, a complete ZnBr battery system, complete with cell stacks, electrolyte circulation pumps, inverters and thermal management system configured into a standard trailer.

Figure 15 - ZnBr Cell Stacks

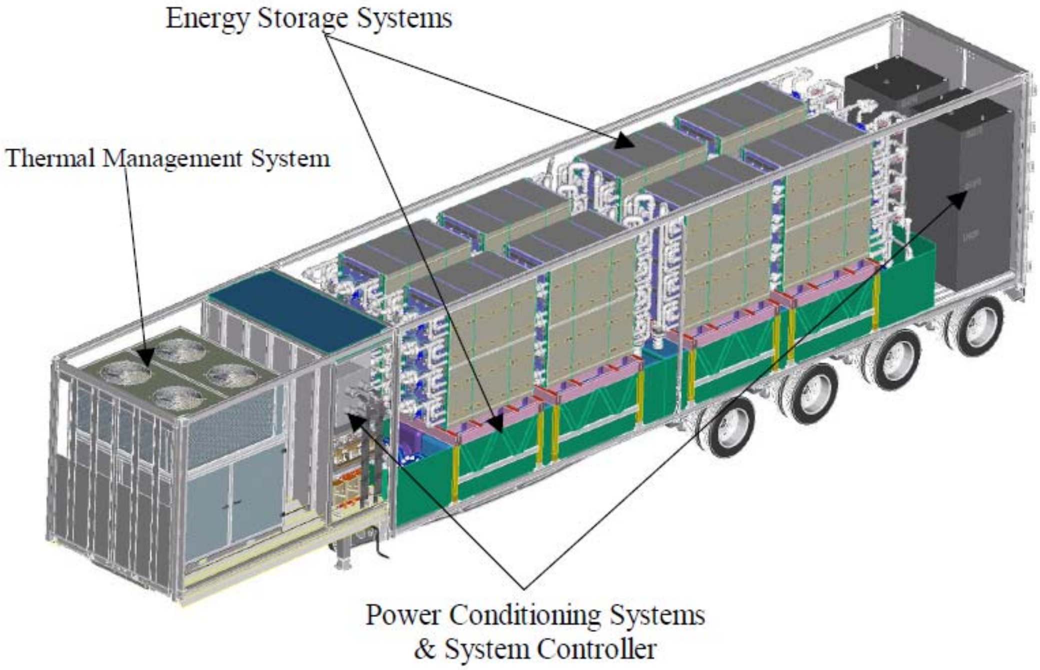


Figure 16 - Premium's TransFlow2000 Section (ZnBr battery)

3.2.2.6 Advanced Lead Acid (Pb-Acid) – Ecoult Energy Storage Solutions (Ecoult)

Lead acid battery technology is tried and proven, and Ecoult, with East Penn, have commercialized UltraBattery, an advanced lead acid battery without the traditional need to maintain a 100% charge. UltraBattery utilizes traditional lead acid reactions with an ultracapacitor.

Ecoult focuses on high power-to-energy applications, primarily involving frequency regulation and power smoothing. However, they have at least one completed and tested project in peak shaving for multiple hours. Ecoult has installed a 3 MW scale demonstration facility, as well as a 3 MW frequency regulation facility on the PJM grid in Pennsylvania. A 3 MW micro-grid application has also been installed that allows an island of 1,500 people to utilize 100% renewable energy. UltraBattery fits best in high power-to-energy ratio applications, such as frequency regulation and renewable energy smoothing. It can achieve efficiencies higher than 90%, and is promoted to be 100% environmentally safe and recyclable. Figure 17 details a 3 MW frequency regulation installation, and Figure 18 shows a typical UberBattery rack.

Figure 17 - 3 MW of frequency regulation at the PJM Interconnection

Figure 18 - UberBattery Energy Block

3.2.3 Summary of Project Data

The following charts summarize the rated capacities of battery storage systems that have been operating or have been contracted to complete installation in the US as provided by the DoE's Energy Storage Database (see Appendix C for a complete list). Data sets do not include any sales projections or forecasts, and only include data points of projects implemented, or projects breaking ground.

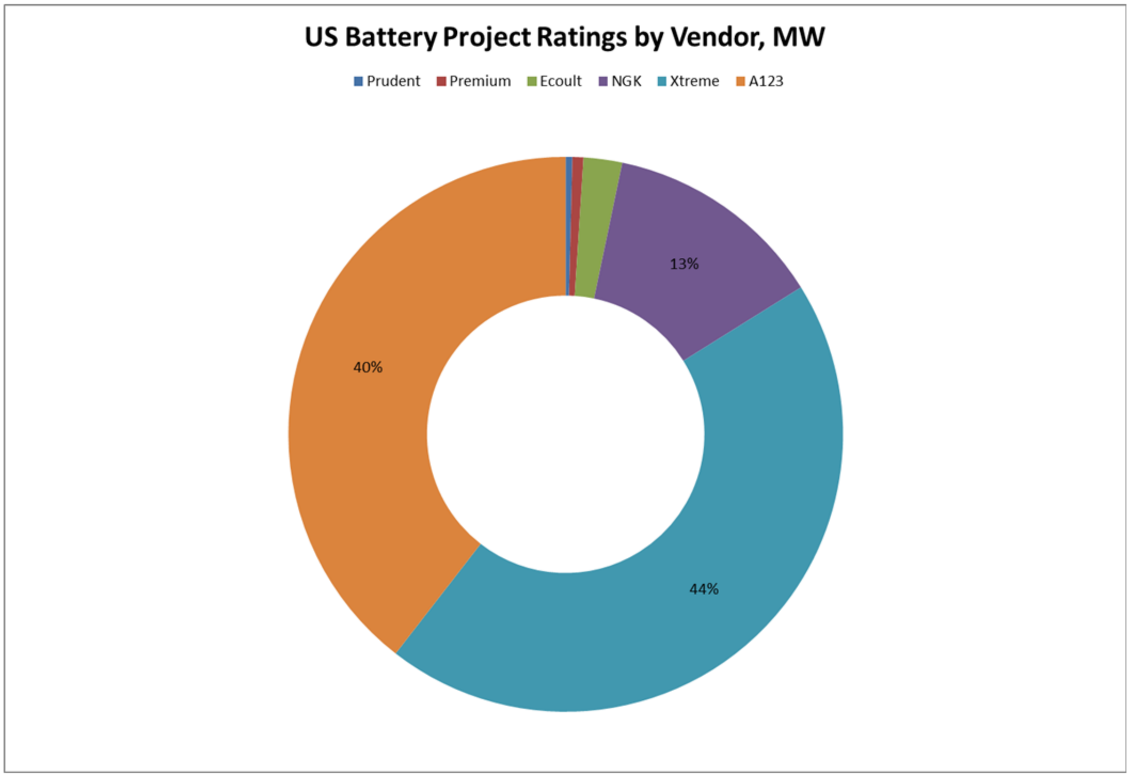


Figure 19 - Rated MW Capacity of US Battery Energy Storage Projects

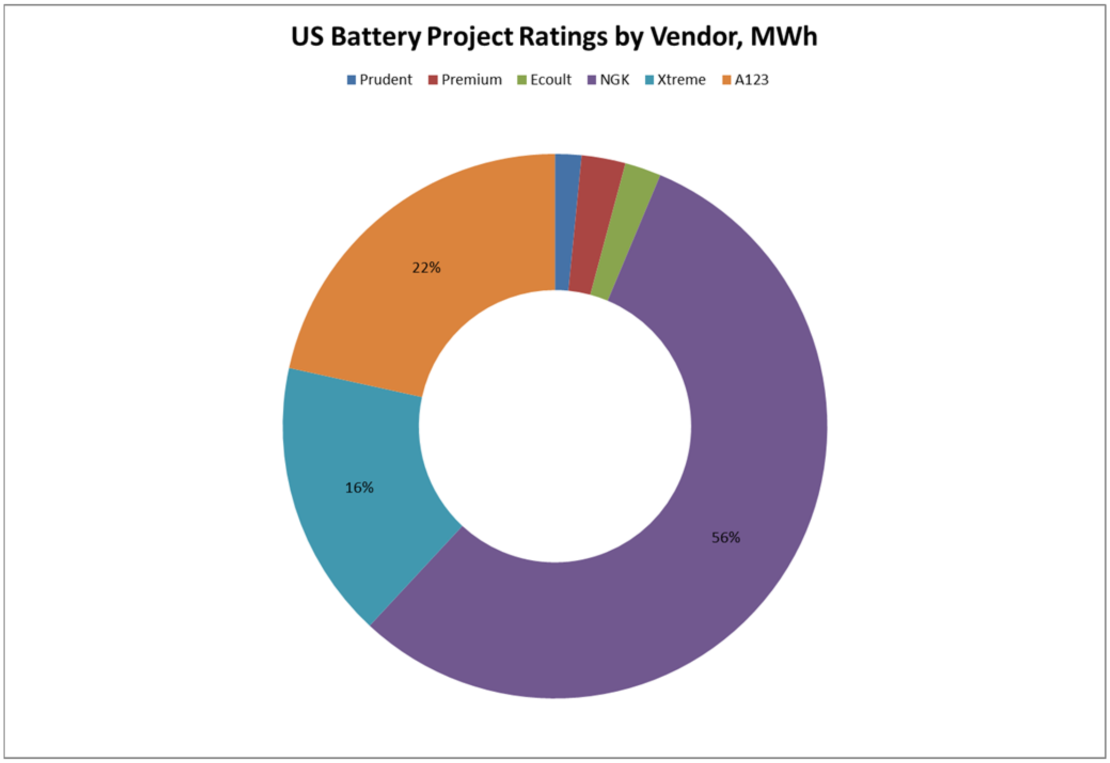


Figure 20 - Rated MWh Capacity of US Battery Energy Storage Projects

Data from the Energy Storage Database provides an approximate indication of the battery industry and should not be construed as an accurate predictor of industry / market behavior. The data collected is not all inclusive of all commercialized manufacturers, does not include all of the projects a given manufacturer has completed, and does not include any emerging technologies that are under final stages of research and development (e.g. American Recovery and Reinvestment Act (ARRA), Advanced Research Projects Agency-Energy (ARPA-E) funding or stealth companies backed by venture capital (VC)s)[3].

3.2.4 Performance Characteristics

Key performance metrics for battery systems include:

- Roundtrip efficiency – alternating current (AC-to-AC) efficiency of complete battery system, including auxiliary loads
- Energy footprint – amount of physical real estate needed to supply certain amounts of energy in kWh per square feet
- Cycle life – estimated effective useful life of operation the battery in operation
- Storage capacity – sub-hourly or multiple hours of discharge times for systems
- Discharge times – time response of battery system

[3] Acronyms:
ARRA = American Reinvestment and Recovery Act of 2009, ARPA-E = Advanced Research Projects Agency – Energy, VC = Venture Capitalists,

- Technology risks – general limitations and concerns of battery systems

Data points collected by manufacturers are summarized in the Technology Matrix in Appendix A.

3.2.4.1 Roundtrip Efficiency

Not all metrics will remain constant throughout a battery system operation and over its life cycle. For almost all technologies, temperature will play a role in performance. Roundtrip efficiencies are also not a constant value and are dependent on the battery State-of-Charge (SOC), temperature and system operations. Losses that are included in roundtrip efficiency estimates include the conversion and storage efficiency of each technology (e.g. voltaic, coulombic, chemical losses), power conversion system losses, transformer losses, and any auxiliary losses due to support equipment (e.g. pumping, cooling, heaters, etc.).

It is also important to distinguish that performance characteristics are generally driven by application requirements – li-ion and dry cell systems have significantly higher roundtrip efficiencies of approximately 90% than does NaS at about 70% or flow batteries at about 60%. In terms of applications, it is the NaS and flow batteries that are generally recognized as providing energy storage in the multiple-hour range (e.g. between 5 to 8 hrs). Roundtrip efficiency is affected by the amount of auxiliary loads needed to support the overall battery system and also by inherent technology inefficiencies. As an example, the flow batteries have chemical inefficiencies because they utilize electrolytes as opposed to solid state cells like li-ion. Flow battery systems also have additional parasitic loads due to the operation of pumps that circulate the electrolyte through the cell stack.

One other contributing factor to roundtrip efficiency includes standby losses that are characterized by self-discharge or by auxiliary loads from support equipment needed to keep battery systems on standby mode. Generally flow batteries (especially during idle time), li-ion and dry cells have the lowest self-discharge rate.

3.2.4.2 Energy Footprint

The energy footprint (square feet per MWh) of battery systems varies considerably, from a few hundred square feet to a few thousand square feet per MWh, depending on technology type and design. Each manufacturer offers standard products, or containerized solutions, as well as custom-designed systems to fit system loads and the physical constraints of the installation (e.g. placing systems in electric utility closet rooms, basements). Solid-state technologies like the li-ion, dry cells, UltraBattery, and NaS will have slightly better energy density than flow battery technology.

HDR advises to use caution when interpreting energy footprint metrics since data points provided by manufacturers range for systems upwards of 1 MW. There will be a fixed amount of real estate needed for every system regardless of MW rating that is dedicated to auxiliary and support equipment (i.e. Power Conversion Systems (PCS), heating, ventilation and air conditioning (HVAC) equipment, transformers), as well as general constraints (i.e. clearances, road access). Premium's TransFlow2000 is currently offered as trailer system and the manufacturer will be offering modular 2.3- and 3-MW plant designs. Depending on the application, footprint may be reduced by constructing a building to house the battery systems rather than the shipping container modules that most manufacturers offer.

It is anticipated that the solid-state battery technology's energy footprint will scale more linearly than that of flow batteries for the reason that energy and power characteristics have been decoupled. Power is a function of electrode surface area and efficiency whereas energy is a function of usable electrolyte. For a flow battery system, a 1 MW plant operating at 1 hour or at 6 hours will have very different footprints. Differences are due to size of storage tanks, as the following illustrates for Premium's VRB system:

- 1 MW at 1 hour = 3,200 square feet (sq. ft.) at 13 ft. tall (volume = 42,000 cubic ft.)
- 1 MW at 6 hours = 4,800 sq. ft. at 16 ft. tall (volume = 78,000 cubic ft.)

Finally, it is anticipated that flow batteries will offer a greater level of flexibility in system sizing design considering independent characteristics. For example, a 1 MW / 1 MWh system requirement will yield very different energy footprints when comparing a NGK NAS system versus a Prudent VRB system.

3.2.4.3 Plant Life

System plant life is the general expectation of the number of years that the battery plant is expected to function with proper operations and maintenance given throughout its service life. Plant life can be expressed in number of years, or more typical of the battery industry to be expressed and the number of cycles. Generally-speaking, one charge and one discharge make up one cycle. The solid state batteries generally have a life expectancy of 5 to 15 years before replacement, while flow batteries are expected to last 30 years.

System operation, aside from the quality of active maintenance, would also play a significant role in determining plant life – i.e. a battery system operating at reduced Depth-of-Discharge (DOD) will have a longer life. Xtreme PowerCellTM cell curve is used as an example of exponentially-changing number of cycles at various DOD:

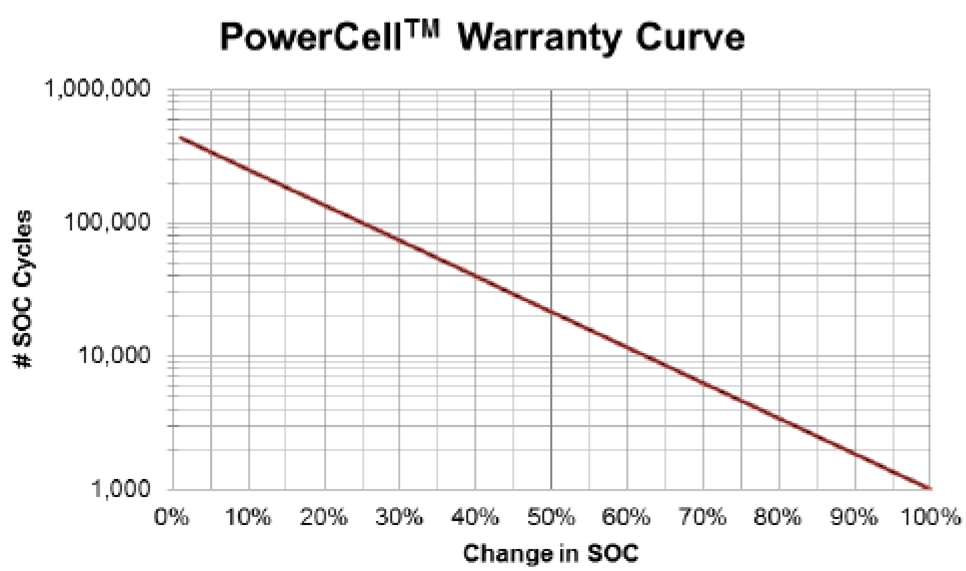


Figure 21 - Typical Battery Life Cycle Curve State of Charge (SOC)

Note that plant life claimed by manufacturers is a compendium of engineering projections, and laboratory testing, while some data points are empirical from field service of battery plants. The flow battery systems claim an indefinite amount of cycles, but have yet to have a battery plant operate for over 20 years – these numbers were instead derived scientifically from tests and research in a laboratory setting. Flow battery systems do not suffer from solids accumulated from electrochemical reactions as with other battery types thus theoretically having a longer life. UltraBattery's life cycle is highly dependent on application. Their 3 MW frequency regulation project operates 5 to 6 full cycles a day, and is expected to last 5 years before cell replacement is required.

3.2.4.4 Storage Capacity

Storage capacity, rated by the number of hours, varies by technology type and application. Ancillary services focusing on frequency regulation and instantaneous bridging power will have sub-hour requirements whereas bulk energy storage and renewables integration will have multiple-hour requirements. All manufacturers highly recommend that detailed system load modeling and detailed load studies be completed prior to entering design phase to allow each manufacturer to offer the best solutions.

NGK's NAS has a maximum storage capacity of 7.2 hours although standard practice is to limit discharge to 6 hours. Prudent's and Premium's flow battery systems have a maximum capacity of 5 hours for standard product offerings, although it is not uncommon to design systems beyond that storage capacity window. A123's li-ion system is geared for two applications: high power requiring 25 minutes or less storage capacity, or the high energy requiring 4 hours or less storage capacity. Xtreme's dry cell systems are focused on applications with 40 minutes or less storage capacity as well as multiple-hour systems up to 3 hours. Ecoult's UltraBattery systems exhibited case studies with as little as a few seconds of discharge time up to 2-3 hours of peak shaving.

3.2.4.5 Discharge Time

Discharge time is a standard measure for a battery energy storage system to reach full output from a state of zero output. This may be a critical consideration for time-sensitive, quick-acting, applications like frequency regulation. The fastest discharge time presented is 7 milliseconds for the ZnBr system followed by 20 milliseconds for the li-ion system, and finally 40 milliseconds for the VRB and UltraBattery sytems. Li-ion systems are generally not suited for quick discharges because it results in generation of immense amount of heat, greatly reducing their efficiency through parasitic loads.

3.2.5 System Details and Requirements

All battery systems use inverters to convert between DC and AC currents. Power electronics (e.g. chargers, transducers) are used to monitor battery cell performance and control overall system performance in real-time. All of these components, and other ancillary control or electronic systems, make up the Power Conversion System (PCS). All manufacturers currently offer PCS design services in-house, and source manufacturing to other reputed components manufacturers like Dynapower, Parker Hannifin, ABB, S&C, GE, Satcon etc.

All battery systems require auxiliary ventilation, road access and some form of telecommunication infrastructure (e.g. radio, telephone line or Local Area Network (LAN) infrastructure). Prudent's VRB will require a building structure to house the battery system and associated support equipment. Premium's ZnBr system is currently marketed as a self-contained trailer system, but it is anticipated that their modular MW-block solutions will also require housing structures. Many manufacturers offer either modular container housing or the ability to be built into an existing or planned structure.

NGK's NAS battery system will require an auxiliary heating source to maintain operating temperatures at 300 degrees Celsius, or 572 degrees Fahrenheit, when the system has idled for a given period of time. The temperature tolerance could not be ascertained. Auxiliary heating is required to keep the battery chemical in a molten state to avoid the phase change of NaS from liquid to solid. Generally, a 7.2-kW electric resistance heater is used to keep cells within required temperature limits only when the battery system is idle. At a system level, parasitic loads can be characterized as 50 kW per 1 MW capacity for its Storage Management System (SMS) and 144 kW (heating) or 56 kW (temperature maintenance mode) per 1 MW capacity for its block heater.

Conversely, A123's li-ion system will require auxiliary cooling for its system, but only during operation, as long as the ambient conditions are between 20 and 30 ^{o}C. Auxiliary cooling is needed because of inherent energy extraction inefficiencies of an electrochemical cell. A battery plant is typically accompanied by a chiller plant. Flow battery systems will generally require some form of cooling for its system. Premium's TransFlow2000 trailer system comes equipped with an integrated chiller. Depending on climate zones, Prudent's VRB plants may require an accompanying chiller plant under warm conditions.

In addition, flow battery systems will have pumps to move electrolytes into each compartment. Prudent's electrolyte supply pumps are controlled by a Variable Frequency Drive (VFD) and power draw cycles between 2.5 kW (standby) and 5 kW (full load operation).

All data points presented by manufacturers on system requirements are summarized in the Technology Matrix in Appendix A.

3.2.6 Technology Risks

Each battery technology shares a certain amount of risk associated with installation and operation. NGK's NAS systems require a heating source when running idle, and a recent fire incident prompted NGK to upgrade battery internals and fire suppression systems accordingly. Its ceramic-aluminum bonds within the beta alumina cell are susceptible to corrosion gradually over a period of 15 years. Leakage of molten sulfur is unlikely, but has happened, and fires are now prevented by additional fuses, insulation boards within the units, and anti-fire boards between stacked modules. Xtreme's battery system is generally limited to 50% depth of discharge, meaning that the battery's charge may not drop below 50%. Prudent's VRB system has a relatively larger footprint than other systems and may require additional space to accommodate a chiller plant depending on site climate. Both flow battery systems share the same life-limiting component in the form of a plastic substrate that lies between the anode and cathode, effectively creating two compartments. Premium's plastic substrate is made out of a high porosity polyethylene that can degrade over time. Power electronics failure was a common concern among the manufacturers.

3.2.7 Capital, Operating and Maintenance Cost Data

Capital costs were collected at the system level to better reflect actual costs associated with each battery system. Based on vendor information, all-in costs for a typical 10 MWh installation at a 6:1 MWh to MW ratio are estimated to be between $17 and $20 million. Subsequent cost numbers do not reflect any site civil development costs and do not include any permitting or planning study costs. Because flow batteries have greater design flexibility in terms of power and energy, cost data is presented on a per kWh basis. System costs, common units either in $ per kW or $ per kWh, should only be compared when examining battery systems for a particular application. For example, A123's li-ion battery systems are quoted for High Power (15 minutes) and High Energy (up to 4 hours).

Throughout its service life, it is anticipated that every battery plant will undergo standard and routine maintenance including general housekeeping, active and preventive maintenance on predominantly electrical equipment (e.g. infrared scanning, visual inspection, replacing capacitors, fans, thermistors). Systems with mechanical equipment such as auxiliary HVAC equipment may require more maintenance (e.g. replacing air filters, pressure transducers, valves).

Battery cells/stacks will need replacement throughout the effective useful life of the battery plant. All manufacturers currently offer standard product warranties spanning no more than 2 years with an option for extension for a certain period of time, or on an annual basis. Xtreme's dry cells have longer standard warranty than the rest at 5 years, although balance of plant is warranted for 2 years.

Component change-out or system repair under warranty is generally carried out by the manufacturer or in some cases, a qualified field service representative. The forced outage rate of all battery systems generally ranges from 0.3% to 3%. Although Prudent and Xtreme currently do not have in-house, contracted, maintenance service capabilities, they do offer comprehensive training services to ensure system owners and operations teams gains an thorough of system performance.

Operating costs can be further defined as follows:

Fixed O&M: Fixed operations and maintenance costs take into account plant operating and maintenance staff as well as costs associated with facility operations such as building and site maintenance, insurances, and property taxes. Also included are general housekeeping, routine inspections of equipment performance and general maintenance of systems. For battery systems with auxiliary cooling equipment (i.e. chiller plants), additional maintenance costs over other battery types will be incurred. General O&M costs will also include spare parts, and component or equipment change-out (i.e. inverter fan filters once they get dusty). For all battery systems, fixed O&M cost will also include the cost of remote monitoring (i.e. cost of telecommunications carrier, secured web hosting / monitoring).

Variable O&M: Variable cost includes the cost of corrective maintenance and other costs that are proportional to unit output. This will likely be, but not limited to, the diagnosing, investigation and testing of components, and the subsequent costs for corrective action.

All cost and maintenance data available from the manufacturers are summarized in the Technology Matrix in Appendix A.

3.3 Compressed Air Energy Storage

3.3.1 CAES Technology Description

Compressed Air Energy Storage consists of a series of motor driven compressors capable of filling a storage cavern with air during off peak, low load hours. At high load, on peak hours the stored compressed air is delivered to a series of combustion turbines which are fired with natural gas for power generation. Utilizing pre-compressed air removes the need for a compressor on the combustion turbine, allowing the turbine to operate at high efficiency during peak load periods.

Compressed air energy storage is the least implemented and developed of the stored energy technologies. Only two plants are currently in operation, including Alabama Electric Cooperative's (AEC) McIntosh plant (rated at 110 MW) which began operation in 1991. The McIntosh plant was mostly funded by AEC, but the project was partially subsidized by EPRI and other organizations. Dresser Rand supplied the compressors and recuperators and is the only known supplier to offer a compressor for the application with a reliable track record. The other plant in operation, the Huntorf facility, is located in Huntorf, Germany which utilizes an Alstom turbine. The equipment utilized in CAES plants, which includes compressors and gas turbines, is well proven technology used in other mature systems and applications. Thus, the technology is considered commercially available, but the complete CAES system lacks the maturity of some of the other energy storage options as a result of the very limited number of installations in operation.

Two primary types of CAES plants have been implemented or are being reviewed for commercial operation: (a) diabatic and (b) adiabatic. In diabatic CAES, the heat resulting from compressing the air is wasted in the process. The air must be reheated prior to expansion. Adiabatic CAES stores the heat of compressions in a solid (concrete, stone) or a liquid (oil, molten salt) form that is reused when the air is expanded. Due to the conservation of heat, adiabatic storage is expected to achieve efficiencies of 70%. Both the McIntosh and Huntorf are diabatic CAES plants. One adiabatic plant is currently under development in Germany.

Other CAES plants have been proposed but, as of yet, have not moved forward beyond conceptual design. These proposed projects include the Western Energy Hub Project, the Norton Energy Storage (NES) project, the PG&E Kern County CAES plant, and the ADELE CAES plant in Stassfut, Germany.

The Western Energy Hub project, promoted by Magnum Energy, LLC (Magnum), is probably the most advanced CAES project under development in the U.S. The salt dome geology has been well characterized, as well as land acquisition and local and state permitting underway.

The first phase of the Magnum project is for natural gas liquids (propane and butane) storage which broke ground in April 2013. This initial phase is expected in service in 2014, and will involve leaching out two caverns for propane and butane storage.

The second phase of the project under development is construction of four additional solution-mined underground storage caverns capable of storing 54 billion cubic feet of natural gas. On March 17, 2011, the Federal Energy Regulatory Commission (FERC) issued an order granting Magnum a certificate of public convenience and necessity under section 7(c) of the Natural Gas Act (NGA) to construct and operate a natural gas storage facility and header pipeline. On February 22, 2011 the Bureau of Land Management (BLM) issued a Decision Record granting Magnum a Right of Way Grant for the header pipeline. Magnum will construct and operate a 61.5 mile header pipeline from its storage facility near Delta to Goshen, Utah. Magnum has also been granted all the necessary permits for construction and operation of the gas storage facility from the State of Utah.

The final phase of the Western Energy Hub project is CAES, in conjunction with a combined-cycle power generation project. The CAES will utilize additional solution-mined caverns to store compressed air. Off-peak renewable generation will be used to inject air into the caverns which will be released during periods of peak power demand. The compressed air will be delivered to a combustion turbine, eliminating the need for a compressor on the combustion turbine, allowing the turbine to operate at high output and efficiency during peak load periods. Magnum plans a total of 1,200 MW of capacity spread across four 300 MW modules, with two days of compressed air at full load. Magnum anticipates an in-service date of around 2017-2018.

The NES Project has been purchased by First Energy. The proposed project was to have an initial capacity of 270 MW, with a potential expanded capacity of 2700 MW project. The project site is located above a 600-acre underground cavern that was formerly operated as a limestone mine in Norton, Ohio. The geological conditions of the site have been assessed by Hydrodynamics Group and Sandia National Laboratories, and the integrity of the mine has been confirmed as a stable vessel for compressed air storage. In December 2012, First Energy suspended construction on the project due to unfavorable economic conditions including low cost of power prices and insufficient demand. As of September 2013, the Ohio Power Siting Board invalidated the certificate at this site.

PG&E has been awarded a $25M grant from the Department of Energy (DOE) to research and develop a CAES plant. The California Public Utility Commission (CPUC) has matched the grant and supplied an additional $25M; the California Energy Commission has supplied an additional $1M of support. The proposed project is a 300 MW plant in Kern County, CA. The first phase is reservoir feasibility study that is scheduled to be completed in Q4 2015. If the project proceeds, the plant is estimated to be operational in 2020. It has not been stated whether the proposed plant will be diabatic or adiabatic and is likely subject to the outcome of the feasibility study.

The ADELE project is an adiabatic CAES plant is Stassfort, Germany. The project is planned to have a storage capacity of 360 MWh, with a total output of 90 MW and projected efficiency of 70%. The project is part of the Federal Government's Energy Storage Initiative and is funded by the German Federal Ministry of Economics and Technology. The initial development phase is funded with $17M (12M Euro) and was expected to be completed by 2013. The total project was expected to have duration of 3.5 years and a cost of $56M (40M Euro). The initial project development is now slated for completion in 2016; the reason for the delay has not been disclosed and the project is still progressing.

3.3.1.1 Technology Risks

CAES has performed very well at the AEC McIntosh plant and therefore little risk is perceived from a technical standpoint provided the proper equipment suppliers are utilized and design factors are considered. Dresser Rand provided the majority of the equipment for the AEC McIntosh plant. The construction of the Huntorf facility in Germany began construction in 1976, a time when gas turbines were not commercially implemented so the Huntorf turbine is a modified steam turbine. Alstom does currently offer a gas turbine for compressed air applications, but none are currently in operation. As such, there is limited potential to competitively bid the major equipment without exposing risk for utilizing first-of-a-kind equipment from an unproven supplier. Another significant risk involves the ability to identify an energy storage geological formation with integrity and accessibility.

Adiabatic designs are under development and introduce new risks into the design of a CAES plant. There are additional heat-storage devices and components in the system that will increase the design complexity of the system. The compressed air is expected to have temperatures in excess of 1,100F, which will require alloyed and/or ceramic materials. There is still uncertainty regarding materials of construction for the compressors and heat storage that would optimize the design. GE Oil & Gas is currently developing an air compressor and air-turbine for use in the ADELE project. A partnership between German companies Zublin and Ooms-Ittner-Hof are developing the heat storage capabilities.

3.3.2 Performance Characteristics

During discharge of the compressed air, the AEC McIntosh plant achieves a fuel heat rate of roughly 4,550 Btu/kWh (HHV). Dresser Rand has made improvements to their CAES equipment offering since the commissioning of the McIntosh plant. These improvements could result in a heat rate of 4,300 Btu/kWh (HHV) but have not been proven on a commercial scale application that is in operation. The primary function of the McIntosh plant is for peak shaving.

The ADELE plant will have similar operating characteristics to McIntosh and Huntorf. The compressors are being designed for compression of up to 1,450 psia; however, the planned storage pressure is 1,015 psia. The total storage capacity is expected to be 360 MWh with an electrical output of 90MW; equivalent to 4 hours of energy storage at full utilization. The big improvement in the adiabatic plant is the round-trip efficiency. The ADELE plant is projected to have a total efficiency in excess of 70%; compared to AEC McIntosh (54%) and Huntorf (42%). The efficiency gains are a result of capturing the heat in the adiabatic process.

3.3.2.1 Site Elevation

Site elevation does impact the performance characteristics of a diabatic CAES plant. In simple cycle combustion turbine plants, the turbine output decreases with increased elevation as a result of the lower air density. Since gas turbines are standardized designs, the compressor and turbine sections are not modified or designed for specific site applications. The compressor size and compression ratio is therefore fixed and the flow rate of air through the compressor decreases as ambient air pressure decreases (i.e. elevation increases). The Compression ratio is the ratio between the discharged air pressure and the inlet air pressure to the compressor. At higher elevations, the compressed air on the turbine side enters the inlet of the gas turbine at a lower inlet pressure as a result of the fixed compression ratio. In turn, less fuel is combusted due to lower air flow rates. Thus, power generation decreases by as much as 20 percent when comparing a combustion turbine at sea level and one at 6,000 feet in elevation.

The same fundamentals apply to CAES technology, except that there is more flexibility in the compressor design which can be decoupled from the gas turbine if desired. This allows a compressor to be designed to achieve a higher compression ratio for higher elevation applications, although the power required to drive the compressor will also increase. On the gas turbine side, the power output can actually increase slightly at higher elevations as a result of a lower turbine exhaust pressure, assuming the inlet pressure is the same as at lower elevations.

The CAES performance is identified in the Technology Summary Matrix at 6,000 feet elevation assuming a plant located in the PacifiCorp service area.

3.3.2.2 Reliability/Availability

Varying sources over varying time periods report that the AEC McIntosh plant offers availability from 86 to 95 percent. At this facility, every air compressor is mounted to a single shaft that is coupled to a combined motor/generator unit via a clutch. Likewise, every turbine is also mounted to a single shaft that is coupled to a combined motor/generator unit via a clutch. Depending on the operational mode, compression or power generation, the motor/generator unit is either coupled to the air compressors or turbines but not both. AEC not only recommends separating the motor for compression and generator for electrical production, but also recommends separating each air compressor and turbine to alleviate maintenance complexities and to increase reliability.

During the design of a CAES plant, careful consideration regarding materials of construction must be undertaken such that materials do not fail or need replacement in an unexpected time frame due to corrosion and abrasive erosion. For example, if a salt cavern is utilized, the turbine manufacturers' specifications regarding the quantity of salts in the incoming air must be considered. Additionally, the Huntorf design offers dual storage caverns which have enabled the plant to achieve approximately 90 percent plant availability. The Huntorf plant experienced corrosion problems with the storage cavern wells; thus, having two storage caverns enabled operation of the plant while one storage cavern was inoperable due to a well head repair.

Due to the high temperatures (>1,100F) of adiabatic plant designs, specialized materials of construction could result in extended lead times for the fabrication of equipment. This would also result in increased cost of the plant to keep critical spares on-site.

3.3.2.3 Start Times

Compressed air energy storage requires initial electrical energy input for air compression and utilizes natural gas for combustion in the turbine. The McIntosh plant offers fast startup times of approximately 9 minutes for an emergency startup and 12 minutes under normal conditions. As a comparison, simple cycle peaking plants consisting of gas turbines also typically require 10 minutes for normal startup.

The Huntorf CAES plant has been designed as a fast-start and stand-by plant; it can be started and run at full-load in 6 minutes.

3.3.2.4 Emission Profiles/Rates

It is expected that CAES will have emissions similar to that of a simple cycle combustion turbine, except reduced by approximately 60 to 70 percent due to reduced natural gas consumption on a per kWh basis.

The diabatic plants, such as AEC McIntosh and Huntorf, require additional natural gas firing for the combustion turbine and for reheating the compressed air. Adiabatic plants, such as ADELE, will not require supplemental firing of natural gas for heating the air, and will have an overall lower plant emissions.

3.3.2.5 Air Quality Control System Design

Dry low mono-nitrogen oxides (NOx) combustion technology can be utilized for control of NOx emissions on the combustion turbine for CAES. If NOx emissions are pushed lower such that dry low NOx combustion technology is insufficient, CAES technology permits use of a selective catalytic reduction (SCR) module, but in this case it would likely be integrated into the recuperator design, permitting close control of the catalyst temperature.

3.3.3 Geological Considerations

There are three types of geological formations generally considered for storing compressed air: salt domes, aquifers, and rock caverns. These formations can then be classified as either constant volume or constant pressure caverns. Constant pressure caverns utilize surface water reservoirs to maintain a constant cavern pressure as the compressed air displaces the water when it is injected into the cavern.

Constant volume caverns have a fixed volume and therefore the air pressure in the cavern decreases as compressed air is released from the cavern. Figure 22 depicts the aforementioned geological formations generally considered for compressed air energy storage.

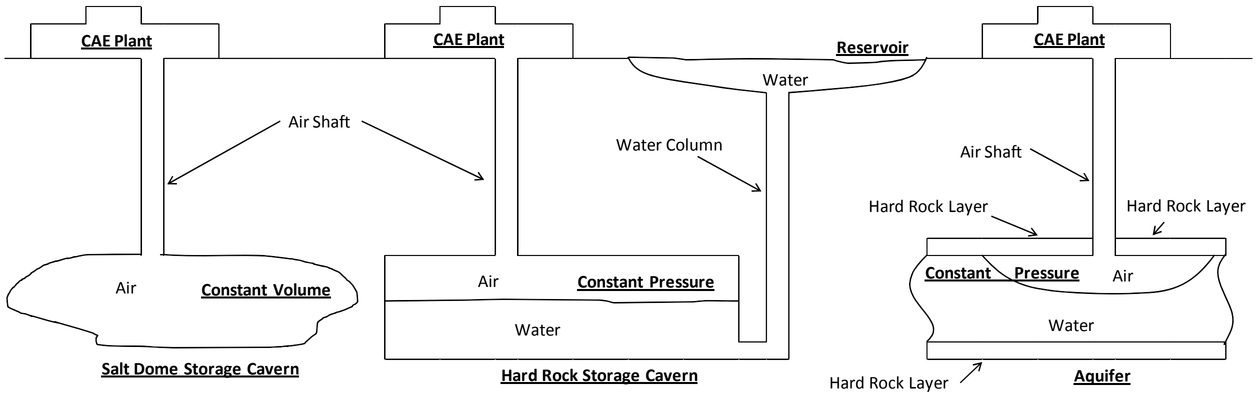


Figure 22 - CAES Geological Formations

Figure 23 depicts an overall map of the continental United States with areas that contain potential geological formations favorable for CAES.

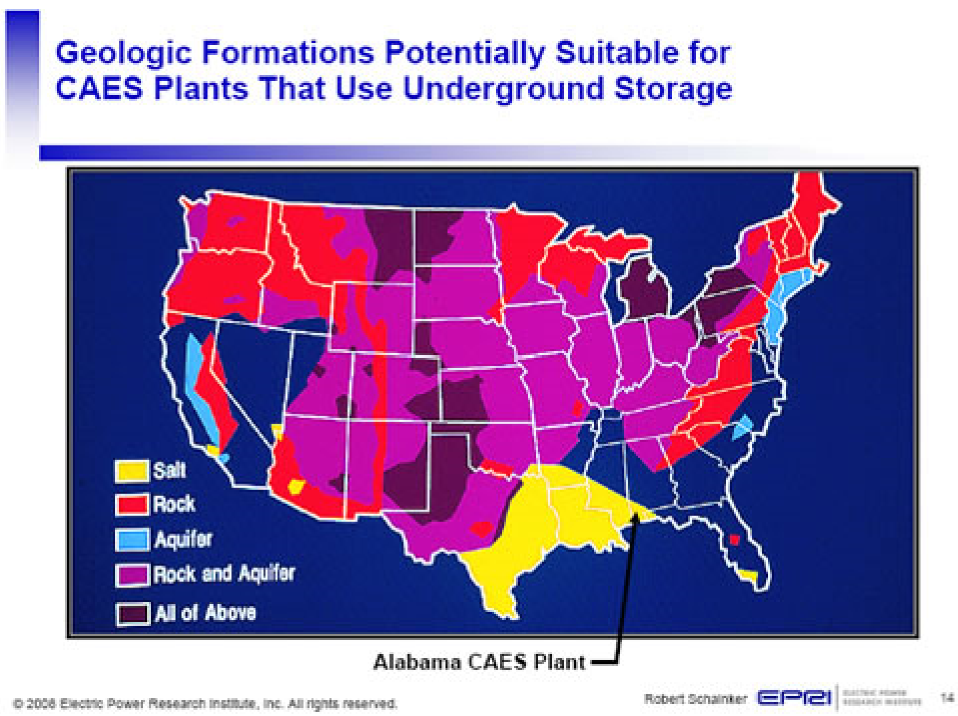


Figure 23 - Potential Geological Formations Favorable for CAES

3.3.4 Capital, Operating, and Maintenance Cost Data

The project schedule for a CAES plant is highly dependent on the manufacturer's lead times for equipment. For the most part, a project should be able to be implemented in a time frame similar to that of a combined cycle combustion turbine plant, if a recuperator is to be implemented, provided the compressed air storage geological formation is available. If a project forgoes a recuperator, the project schedule can be reduced by four to six months. If a salt cavern must be drilled and solution mined before implementation, this time frame becomes dependent upon the process used to permit and prepare the cavern. Solution mining the cavern may take up to 18 to 24 months, but can be done in conjunction with construction of the CAES plant.

Based on information gathered from similar projects in development, expected project duration is summarized in Table 6.

Table 6 - CAES Typical Project Schedule

Task	Duration
Test well	10 mo.
Preliminary design	3 mo.
Permitting	12 mo.
Final design	6 mo.
Construction	24 mo.
Sum of Tasks	55 mo.

CAES options can vary considerably depending upon the specific project. The power island for a CAES option is typically small and similar in size to that of a combined cycle plant. Construction of the underground storage reservoir is a significant contributor to the cost of CAES. Aquifers and depleted gas reservoirs are the least expensive storage formations since mining is not necessary. Salt caverns are the most expensive storage formations since solution mining is necessary before storage. Storage formations vary in depth but most formations that can currently be utilized range between 2,500 ft to 6,000 ft below the earth's surface. Storage formations vary naturally in size but storage caverns can be appropriately mined to achieve a specific storage capacity.

3.3.4.1 Capital Costs

The McIntosh project was commissioned in 1991 and at that time cost $65 million. Since the McIntosh plant offers 110 MW of net power, the plant cost was $590/kW.

The Iowa Stored Energy Park (ISEP) was originally estimated at approximately $400 million for a plant size of 270 MW. A detailed Sandia report on the lessons learned from the ISEP CAES plant is available in Appendix D.

Projected cost information has not been made available for the PG&E Kern County and ADELE CAES plants.

Due to the limited number of CAES projects completed and vague task descriptions often associated with project costs as well as external funding that was provided for McIntosh, HDR estimates that CAES project capital costs would be in the range of $1,600/kW to $2,200/kW for a 300 to 500 MW diabatic CAES plant, including ten hours of solution-mined storage capacity. The technology for an adiabatic plant has not been made public and a capital cost cannot be accurately projected at this time; the total capital cost will be greater than a diabatic plant. HDR assumes project capital costs to include project direct costs associated with equipment procurement, installation labor, and commodity procurement as well as construction management, project management, engineering, and other project and owner indirect costs. This estimate does not include storage cavern cost. Values are presented in 2014 dollars.

3.3.4.2 Operating Costs

Fixed O&M: Fixed operations and maintenance costs take into account plant operating and maintenance staff as well as costs associated with facility operations such as building and site maintenance, insurances, and property taxes. Also included are the fixed portion of major parts and maintenance costs, spare parts and outsourced labor to perform major maintenance on the installed equipment. The estimated fixed O&M costs for the ISEP CAES plant would be $18.78/kW in 2014 USD. Fixed O&M costs are expected to be similar for a diabatic CAES facility. An adiabatic plant would have greater fixed O&M costs due to increased complexity in the system design.

Variable O&M: The non-fuel related variable O&M costs for the ISEP CAES plant is estimated to be $2.28/MWh in 2014 USD. Variable O&M costs are expected to be similar for a diabatic CAES facility. Additional variable O&M for fuel and electric costs should be considered when evaluating a diabatic plant. Fuel and electric costs should be considered based on existing gas and power purchase agreements or local market pricing.

3.4 Flywheels

3.4.1 Flywheel Technology Description

Flywheels are electromechanical energy storage devices that operate on the principle of converting energy between kinetic and electrical states. A massive rotating cylinder, usually spinning at very high speeds, connected to a motor stores usable energy in the form of kinetic energy. The energy conversion from kinetic to electric and vice versa is achieved through a variable frequency motor or drive. The motor accelerates the flywheel to higher velocities to store energy, and subsequently slows the flywheel down while drawing electrical energy. Flywheels also typically operate in a low vacuum environment to reduce inefficiencies. Superconductive magnetic bearings may also be used to further reduce inefficiencies.

Generally, flywheels are used for short durations to supply backup power in a power outage event, or for regulating voltage and frequency.

3.4.2 Manufacturers

A quick market survey of the energy storage industry reveals that there is only one flywheel technology manufacturer that has achieved utility market commercialization: Beacon Power Corporation with their Generation 4 Flywheels.

Newer technology flywheel systems utilize a carbon fiber, composite flywheel that spins between 8,000 and 16,000 revolutions per minute (RPM) in an extremely low friction environment, near vacuum, using hybrid magnetic bearings. Flywheels store energy through its mass and velocity.

Flywheels are recognized for potentially long service life, fast power response and short recharge times. They also tend to have relatively high turnaround efficiency on the order of 85%. This energy storage technology is classified as commercial in regards to utility applications.

Beacon offers its flywheel technology and balance of system plants as the Smart Energy 25 product. In 2011, the company entered bankruptcy protection. In 2012, Beacon's assets, including the 20 MW

Stephentown NY storage plant (Figure 24), were bought by a private equity firm, Rockland Capital. Beacon offers turn-key solutions in the US and Europe, and also provides in-house operating and maintenance services.

Figure 24 - Flywheel Plant Stephentown, New York

3.4.3 Performance Characteristics

A few performance characteristics of flywheels include: low lifetime maintenance, operation can typically be of high number of cycles, 20-year effective useful life and since kinetic energy is used as the storage medium, there are no exotic or hazardous chemicals present.

Roundtrip AC-to-AC efficiency of the system is in the order of 85% with primary parasitic loads being the Power Conversion System (PCS) and internal cooling system, among the mechanical and friction losses of the system. Beacon estimates the energy losses through a flywheel plant to be in the order of 7% or less of energy throughput of the plant. Primary losses are intrinsic, and include friction (between rotor and environment) and energy conversion losses (generator losses including windings, copper, induction).

Energy footprint for flywheels is generally large and comparable to that of pumped hydropower. Plant life is expected to be 125,000 cycles (at 100% DOD) over a period of 25 years with no change in energy storage capacity resulting in a high amount of energy throughput throughout its effective useful life.

Flywheel's largest limitations are its large energy footprint and its relatively short energy storage duration of 15 minutes or less per system. System response times are less than 4 seconds and ramp up/down rates can be 5 MW per second. This makes it an ideal candidate to serve in the frequency regulation services to the grid operator while maintaining reliability. According to Beacon, one technology risk associated with flywheel systems lie in its power electronics modules which have statistically failed once every 150,000 hours of operations. There is also risk associated with catastrophic flywheel failure. Two flywheels failed at Stephentown soon after installation.

3.4.4 Manufacturer Pros and Cons

Beacon is considered in the industry as a pioneer in developing utility scale flywheel energy storage systems. To date, the company has five projects in the U.S. with a nameplate capacity of 26 MW. A significant portion of Beacon's services are focused on regulation services. Another Beacon flywheel energy storage project (20 MW) is currently under construction in Hazle Township, PA. Additionally, Beacon is studying the implication of integrating a 200-MW flywheel energy storage system at a wind farm in Ireland.

3.4.5 Capital, Operating and Maintenance Cost Data

Capital and operating cost data points from Beacon Power Corporation remains proprietary and cannot be disclosed unless a Non-Disclosure Agreement (NDA) has been signed and executed. However, data points from publicly-available documents suggest that the 20 MW Beacon flywheel plant is estimated to cost $50 million. This yields $2,400 per installed kW.

Throughout its service life, it is anticipated that the flywheel system will require standard and routine maintenance including general housekeeping and preventive maintenance on its electrical equipment. The flywheel plant will require telecommunications infrastructure (e.g. radio, telephone or local area network (LAN) to allow for remote monitoring.

3.5 Liquid Air Energy Storage (LAES)

3.5.1 LAES Technology Description

LAES uses off-peak electricity to cool air from the atmosphere to minus 195 °C, the point at which air liquefies. The liquid air, which takes up one-thousandth of the volume of the gas, can be kept for a long time in a large vacuum flask at atmospheric pressure. At times of high demand for electricity, the liquid air is pumped at high pressure into a heat exchanger, which acts as a boiler. Either ambient air or low grade waste heat is used to heat the liquid and turn it back into a gas. The massive increase in volume and pressure from this is used to drive a turbine to generate electricity.

3.5.2 LAES Performance

In isolation the process is only 25% efficient, but this can be increased (to around 50%) when used with a low-grade cold store, such as a large gravel bed, to capture the cold generated by evaporating the cryogen. The cold is re-used during the next refrigeration cycle. Efficiency is further increased when used in conjunction with a power plant or other source of low-grade heat that would otherwise be lost to the atmosphere.

A 300 kW, 2.5MWh storage capacity pilot cryogenic energy system developed by researchers at the University of Leeds and Highview Power Storage, that uses liquid air (with the CO2 and water removed as they would turn solid at the storage temperature) as the energy store, and low-grade waste heat to boost the thermal re-expansion of the air, has been operating at a biomass power station in Slough, UK, since 2010. The efficiency is less than 15% for this pilot plant.

3.6 Supercapacitors

3.6.1 Supercapacitor Technology Description

Supercapacitors bridge the gap between conventional capacitors and rechargeable batteries. They have energy densities that are approximately 10% of conventional batteries, while their power density is generally 10 to 100 times greater. This results in much shorter charge/discharge cycles than batteries. Additionally, they will tolerate many more charge and discharge cycles than batteries.

Supercapacitors have advantages in applications where a large amount of power is needed for a relatively short time, where a very high number of charge/discharge cycles or a longer lifetime is required. Typical applications range from milliamp currents or milliwatts of power for up to a few minutes to several amps current or several hundred kilowatts power for much shorter periods. Supercapacitors do not support AC applications.

3.6.2 Supercapacitor Performance

Supercapacitors support a broad spectrum of applications, including:

- Stabilizing power supply in hand-held devices with fluctuating loads.
- Providing backup or emergency shutdown power to low-power equipment such as RAM, SRAM, micro-controllers and PC Cards.
- Power for cars, buses, trains, cranes and elevators, including energy recovery from braking, short-term energy storage and burst-mode power delivery.
- Providing uninterruptible power supplies where supercapacitors have replaced much larger banks of electrolytic capacitors.
- Providing backup power for actuators in wind turbine pitch systems, so that blade pitch can be adjusted even if the main supply fails.
- Stabilizing within milliseconds grid voltage and frequency, balancing supply and demand of power and managing real or reactive power.

3.7 Superconducting Magnet Energy Storage (SMES)

3.7.1 SMES Technology Description

Superconducting Magnetic Energy Storage (SMES) systems store energy in the magnetic field created by the flow of direct current in a superconducting coil which has been cryogenically cooled to a temperature below its superconducting critical temperature.

A typical SMES system includes three parts: superconducting coil, power conditioning system and cryogenically cooled refrigerator. Once the superconducting coil is charged, the current will not decay and the magnetic energy can be stored indefinitely.

The stored energy can be released back to the network by discharging the coil. The power conditioning system uses an inverter/rectifier to transform alternating current (AC) power to direct current or convert DC back to AC power. The inverter/rectifier accounts for about 2–3% energy loss in each direction.

3.7.2 SMES Performance

SMES loses the least amount of electricity in the energy storage process compared to other methods of storing energy. SMES systems are highly efficient; the round-trip efficiency is greater than 95%.

Due to the energy requirements of refrigeration and the high cost of superconducting wire, SMES is currently used for short duration energy storage. Therefore, SMES is most commonly devoted to improving power quality. The most important advantage of SMES is that the time delay during charge and discharge is quite short. Power is available almost instantaneously and very high power output can be provided for a brief period of time.

There are several small SMES units available for commercial use and several larger test bed projects. Several 1 MWh units are used for power quality control in installations around the world, especially to provide power quality at manufacturing plants requiring ultra-clean power, such as microchip fabrication facilities.

These facilities have also been used to provide grid stability in distribution systems. In northern Wisconsin, a string of distributed SMES units were deployed to enhance stability of a transmission loop. The transmission line is subject to large, sudden load changes due to the operation of a paper mill, with the potential for uncontrolled fluctuations and voltage collapse.

4 COMPARISON OF STORAGE TECHNOLOGIES

HDR has performed an initial comparison of the energy storage technologies discussed in this document. The full comparison can be seen in the energy storage matrix in Appendix A. Table 7 below lists some of the key criteria that were compared when considering these technologies.

Table 7 - Energy Storage Comparison Summary

	Pumped Storage Hydro (Three sites)	Batteries	Compressed Air Energy Storage
Range of power capacity (MW) for a specific site	600 – 1,500	1-32	100+
Range of energy capacity (MWh)	5,280 – 16,500	Variable depending on DOD	800+
Range of capital cost ($ per kW)	$1,700-$2,500	$800-$4,000	$2,000-$2,300
Year of first installation	1929	1995 (sodium sulfur)	1978

The following sections provide comments on the overall commercial development of the technology, the applications suited to each technology, space requirements for each technology, performance characteristics, project timelines, and capital, operating and maintenance costs.

4.1 Technology Development

Figure 25 below by the California Energy Storage Association (CESA) illustrates the installed capacity of various energy storage technologies worldwide. Pumped storage is by far the most mature and widely used energy storage technology used not only in the US, but worldwide. In the U.S., pumped storage accounts for over 20,000 MW of capacity. By comparison, there is only one existing CAES facility in the U.S., with a capacity of 110 MW. Sodium-sulfur (Na-S) batteries have been used in Japan with the largest installation supplying approximately 34 MW of capacity for 6-7 hours of storage; this technology is gaining popularity in the U.S. Sixteen MW of lithium-ion (Li-ion) batteries have also recently been installed in Chile, and a 2-MW pilot project has been executed in the U.S. CAES systems, batteries, super capacitors, flywheels, and pumped storage were compared in a number of reports by Sandia National Laboratories (Sandia), Pacific Northwest National Laboratories (PNNL), and by the California Energy Storage Association (CESA).

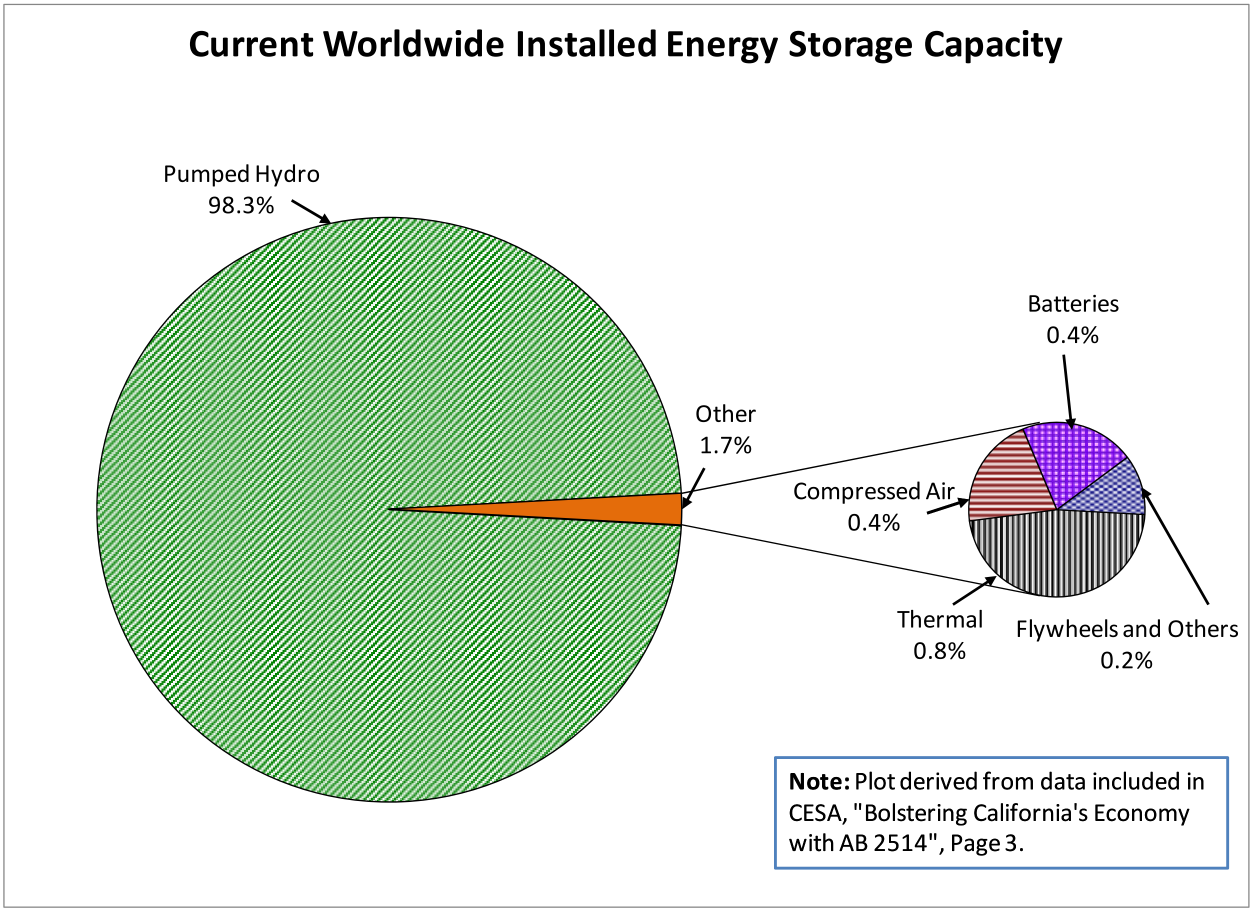


Figure 25 - Current Worldwide Installed Energy Storage Facility Capacity (Source: CESA)

4.2 Applications

Pumped storage and CAES are considered to be the only functional technologies suitable for bulk energy storage as stand-alone applications. Bulk energy storage can be considered multi-hour, multi-day or multi-week storage events. Batteries and flywheels are most functional as a paired system with variable generation resources or for distributed energy storage on a smaller kW and kWh basis. Each of the technologies is capable of providing ancillary services such as frequency regulation and other power quality applications with bulk storage technologies also able to provide system load following and ramping capabilities.

4.3 Space Requirements

Space requirements for energy storage systems vary depending upon capacity and power, and it is often difficult to perform an apples-to-apples comparison of the space requirements for the four technologies discussed above. Pumped storage and CAES are capable of much higher capacities and total energy storage and therefore their project footprint is substantially higher. For example, Table 8 below indicates the surface space requirements for comparable 20,000 MWh facilities: a 1,000-MW, 20-hour pumped storage plant (including upper and lower reservoirs), a Li-ion battery field, and a Na-S battery field. The space required for a pumped storage facility, including reservoirs, is somewhat less in acreage than a Na-S battery field, and far less than that of a Li-ion installation. The artist's rendering in Figure 26 illustrates the number and size of the Li-ion batteries necessary to store 20,000 MWh of energy. The resulting 1,100 acres would be equivalent to approximately 833 football fields. For scale, a typical pumped storage powerhouse is indicated in the foreground.

Table 8 - Space Required for 20,000 MWh of Energy Storage

Project Type	Approximate Footprint (Acres)
Sodium Sulfur Batteries	270
Li-ion Battery Field	1,100
Pumped Storage Reservoirs	220

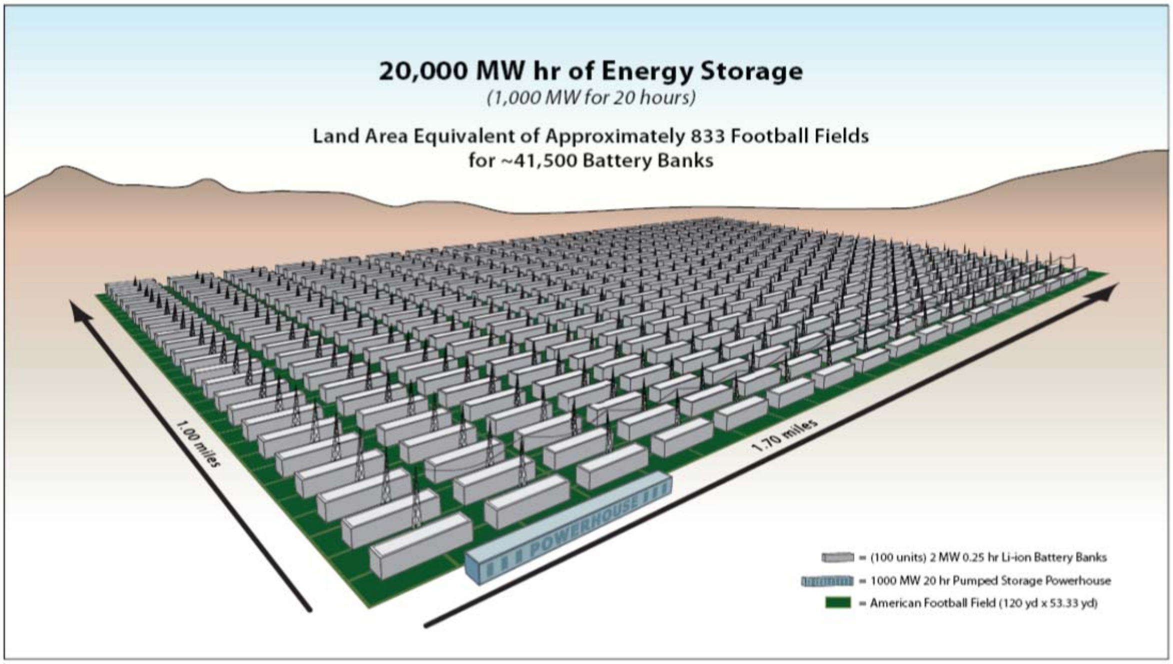


Figure 26 - Li-ion Battery Field and a Hydroelectric P/S Plant for 20,000 MWh of Storage (Source: HDR)

4.4 Performance Characteristics

Project capacity and duration are the most important characteristics for bulk energy storage. For reference, Figures 27 and 28 illustrate the current capability of energy storage technologies. Included in these figures are pumped storage, CAES, various battery technologies flywheels as well as capacitors. Figure 27 is derived from Figure 28 and utilizes the same data, though plotted on a linear scale versus a log-log scale to better reflect the real-time MW and MWh capability of the different technologies. Figure 27 allows for a truer comparison of technologies with smaller capacities and discharge times to larger, longer duration energy storage systems. Figure 28 allows for a closer view of the smaller energy storage technologies.

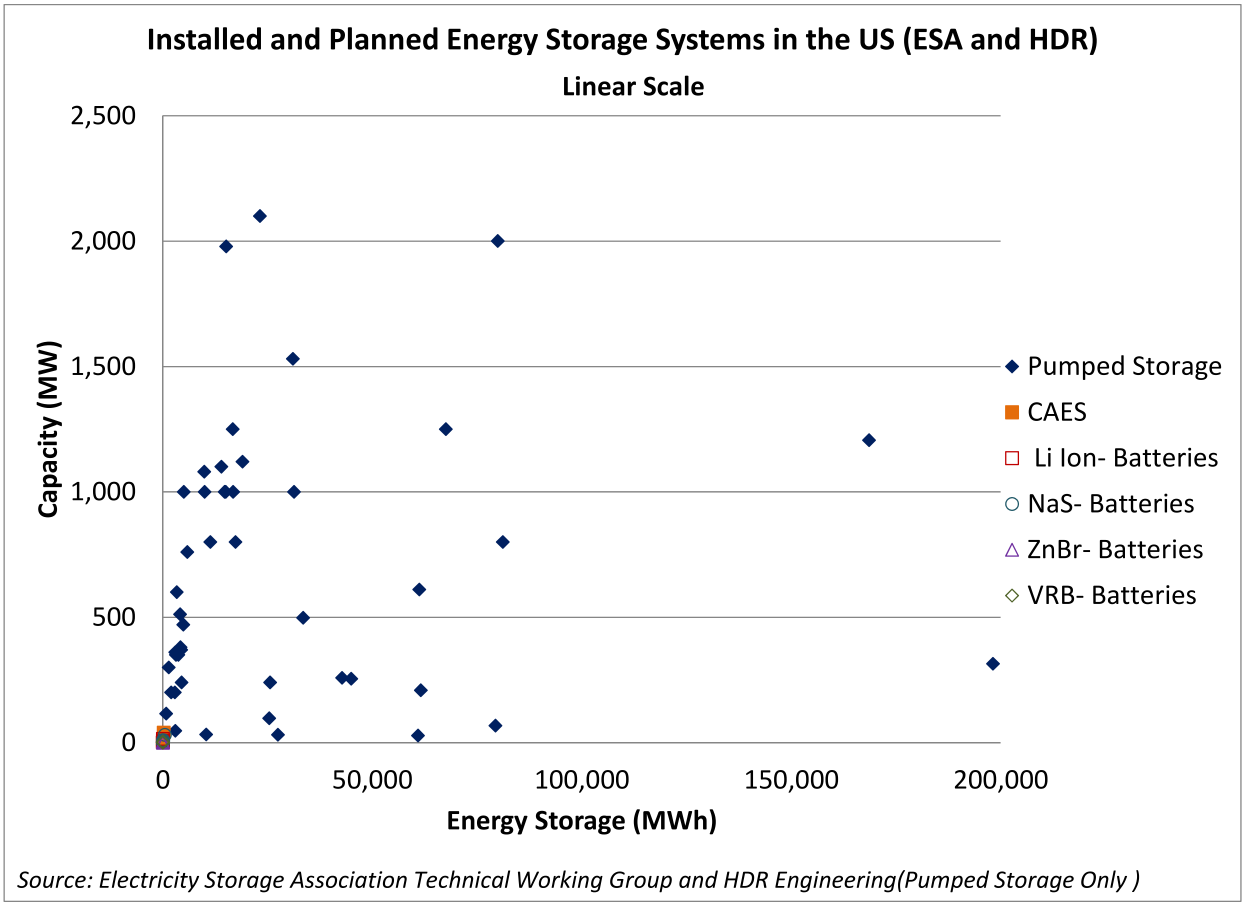


Figure 27 - Current Energy Storage Technology Capabilities in Real Time (Source: HDR)

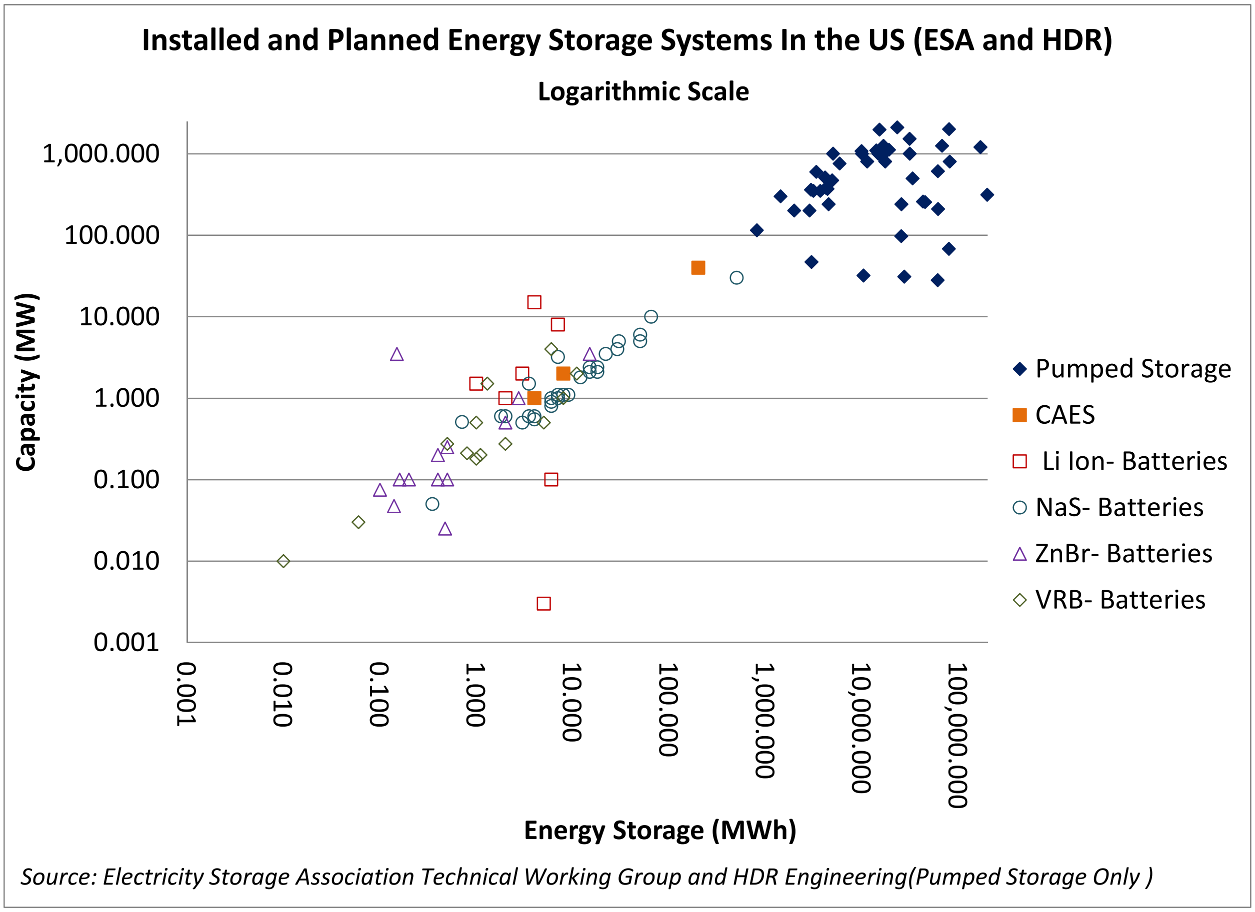


Figure 28 - Current Energy Storage Technology Capabilities (Log-Log Scale) (Source: Electricity Storage Association)

4.5 Project Timeline

Project timelines vary widely for the various options. Pumped storage lead times require a FERC licensing process which takes on average 5 years. An additional five years is typically required for construction. Greenfield closed loop systems are expected to be shorter to license. There are also efforts within the industry to reduce licensing times and develop more streamlined processes. An example pumped storage development schedule is attached to this document in Appendix B. The timelines for CAES are on the order of 2 years. For both pumped storage and CAES it is assumed that a project location has been identified, and for CAES, the geology of the cavern has been verified. Batteries and flywheels have no licensing requirements and fewer restrictions on land use, so their development times are significantly shorter, on the order of 1 year.

4.6 Cost

There are a number of challenges associated with comparing the different types of energy storage technology. While a conscientious effort was made to discuss the technologies in terms of similarly sized capacities and durations, this comparison is somewhat difficult as the maximum hours of available storage and maximum capacity vary widely from 1 or 2 MW for a lithium-ion battery to over 1,000 MW for a pumped storage project. As noted earlier, many of these storage systems are still undergoing significant product development, and the maximum storage, capacity, lifetime, capital costs, and lifecycle costs of these technologies have yet to be determined. Also for pumped storage and CAES, site specific conditions can significantly impact the cost and spatial needs for any given project. These challenges emphasize the idea that a portfolio of many different storage technologies may be needed. Table 9 and Figure 29 were developed by HDR based on the information presented in the matrix in Attachment A. While this information is helpful in understanding the capital and O&M costs on a $ per kW basis, for some technologies, especially batteries, capital costs are better represented with both capacity (kW) and storage (kWh) elements. The capital cost per kW is shown in Table 9 below.

Table 9 - Summary of Cost and Capacity Data (2014 $US)

	Pumped Storage	**A123 Li-Ion**	**NGK NAS**	**Prudent VRB**	**Xtreme Dry Cell**	**Premium ZnBr**	**Ecoult Adv. Pb-Acid**	**CAES**
System Cost ($/kW and/or $/kWh)	$1,700- $2,500 per kW	$800 - $1,000 per kW (High Power) $800 - $1,200 (High Energy) per kWh	$4,000 per kW	$675 per kWh	$1,900 - 2,100 per kW	$1,500 - $2,200 per kWh	~$1,700 per kW, highly dependent on application	$2,000- $2,300 per kW
Rated System (MW)	1000	1 (High Power) 89 (High Energy)	1	1	1	0.5	1	100+
Rated Capacity (hrs)	8 - 10	0.25 (High Power) 4(High Energy)	7.2 max (standard discharge is 6)	1	0.67 to 2	1	40 ms to 3 hours	8

Capital cost is one initial indicator of project economics, but long-term annual O&M costs may provide a more comprehensive representation of financial feasibility. Figure 29 compares annual costs per kW of various technologies. This figure was updated from the 2011 IRP to escalate costs to 2014 USD by a factor of 6%. Because of the significant difference in capacity of the technologies, the figure is shown in a logarithmic scale. A linear version of the plot is shown in the upper left corner of the figure. Pumped storage O&M costs vary from site to site as discussed above, but economy of scale keeps the O&M cost per kW low. The pumped storage costs represented in Figure 29 are for a 1,000 MW project. CAES's O&M costs are estimated at 4% of the overall installed cost. The operating and maintenance costs associated with batteries are high, but vary depending upon the technologies. As battery technology develops further, and grid scale installations continue, a better understanding of the costs associated with operation and maintenance will be achieved.

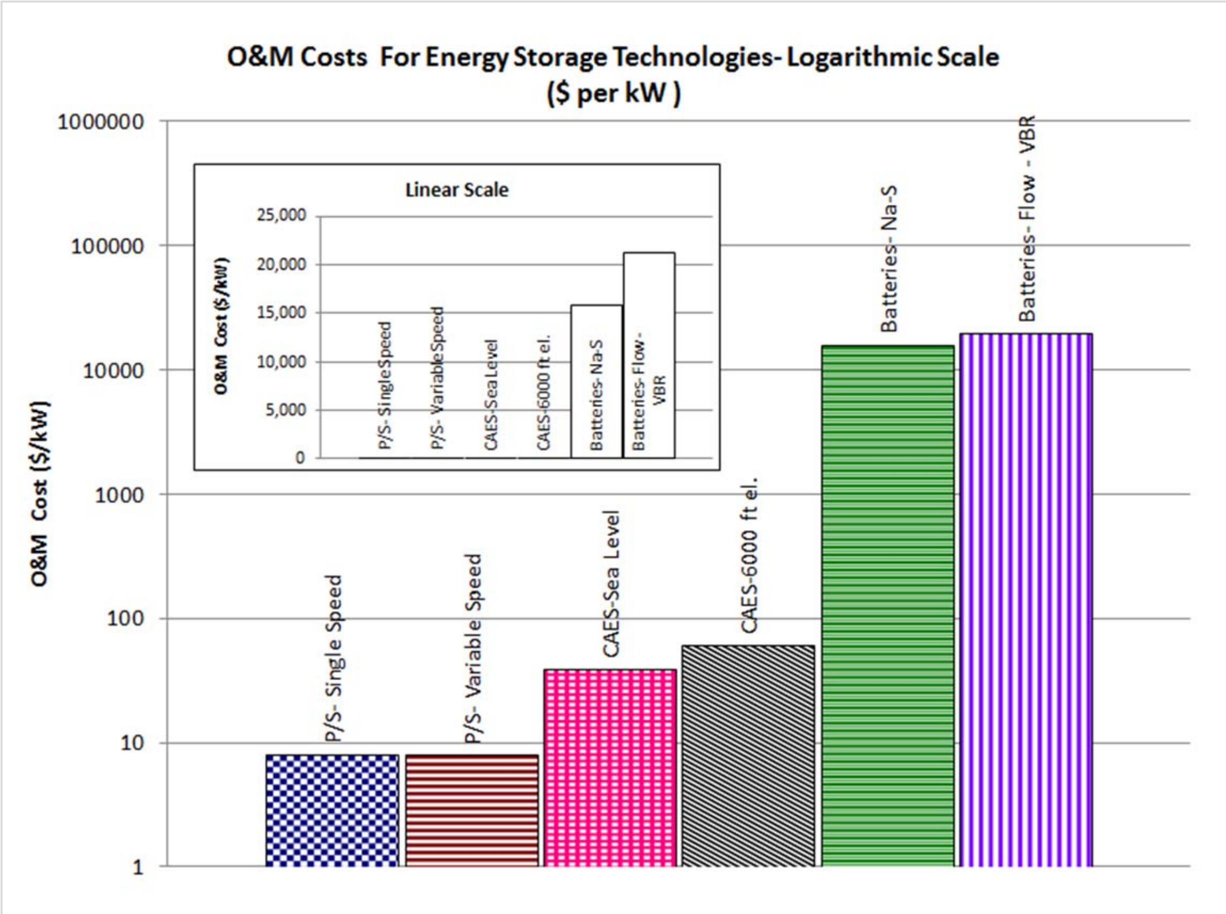


Figure 29 - Operation and Maintenance Costs for Energy Storage Technologies

5 CONCLUSIONS

A number of technologies would be required to smooth variable energy resources, including bulk storage, distributed storage, and transmission system improvements. While there is much debate about the application of new energy storage technologies, for high capacity applications greater than 50 MW, pumped storage represents the least-cost grid-scale storage technology. Pumped Storage is a proven and attractive option in terms of space required, total life cycle costs, and proven MW and MWh capacity. Although CAES has the potential to provide relatively similar bulk storage capabilities, its limited heritage, low efficiency and requirement for geologic-specific siting makes it difficult to implement. For applications less than 50 MW with the goal towards improving the performance of individual, variable energy sources, or a group of such sources, battery and flywheel systems become a feasible alternative. Additionally, battery and flywheel systems have been successfully employed with lower capacities and shorter durations, which make them well suited to short-term storage for general grid stabilization and power quality needs on the order of minutes to a few hours. A variety of complementing technologies will be required to fully address the effects of variable renewable energy, including bulk storage, distributed storage, consolidated balancing areas, and improvements to the interconnecting transmission system.

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APPENDICES

APPENDIX A – ENERGY STORAGE MATRIX

Energy Storage Study - Technology Summary Matrix
Client: PacifiCorp Energy
By: HDR Engineering
July 9, 2014

Summary

	Item	Pumped Storage Hydro					Batteries						Compressed Air Energy Storage
		General	Single Speed	Variable Speed	Closed Loop (1)	Open Loop (2)	Lithium Ion	Sodium Sulfur	Flow - Vanadium Redox	Dry Cell	Advanced Lead-Acid	Flow - Zinc Bromine	6000 ft Elevation Operation
1	Range of power capacity (MW) for a specific site	9 - 2800	9 - 2800	85 - 600 (internationally)	28 - 2700	9 - 2000	1 - 32	1 - 12	0.250 - 10	1.5 - 19.5	1 - 18	0.5 - 20	100 MW +
2	Range of energy capacity (MWh)	87-370,000	87-370,000	same capacity as single speed (NA in US)	247-190,000	87-370,000	Variable depending on depth of discharge (DOD)						800 MWh +
3	Range of capital cost ($ per kW $ per kWh or as applicable)	$1,700-$2,500 per kW[4]					$800 to $1,000 per kW for High Power system ($800 to $1,200 per kWh for High Energy system)[5]	$4,000 per kW[6]	Unknown capital per kW $675 per kWh[7]	$1,900 - 2,100 per kW[7]	Approximately $1,700 per kW, highly dependent on application[8]	$1500 - $2200 per kWh at assumed 6:1 energy to power ratio[9]	$2,000 - $2,300 per kW including 8 hr salt cavern
4	Year of first installation	1929	1929	1990 (Japan)	1963	1929	2009	1995	2004	2009	unknown, 2010-2011	unknown- 2000's	1978
5	Commercial status for grid applications (developmental, commercial, mature)	mature	mature	commercial	mature	mature	commercial	mature	commercial	developmental	commercial	commercial	Commercial
6	Typical project lead times (years)	5 licensing 5 construction	5 licensing 5 construction	5 licensing 5 construction	< 5 licensing 5 construction	> 5 licensing 5 construction	1 yr	1 yr	1 yr	1 yr	1 yr	1 yr	24 to 28 months
7	Project footprint/energy density (ft^2 per MWh)	Varies depending upon head and reservoir size, for example, Bath County has 700 acres for 2700 MW					TBD	TBD	TBD	TBD	TBD	TBD	20 acres for 135 MW Block
8	Potential fatal flaws to commercial viability	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing	Possible failure with power electronics module. Aggressive discharge rates may overheat batteries.	Sealing deteriorates after 15 years	Plastic containers	Improper terminations possible	No catastrophic failure mode	Polyethylene plastic substrates	Satisfactory Geology

1. Closed loop system- A pumped storage system in which the upper and lower reservoirs are connected by a relatively short water conveyance system and the dams are not on a main-stem river.
2. Open loop system- A pumped storage system in which one or more of the dams are on a main-stem river.
3. Schedule for CAES assumes that the cavern geology project has already been identified and confirmed.
4. Values adjusted in accordance with 2014 assessment of Swan Lake, JD Pool, and Black Canyon projects.
5. Data per discussion with A123 Systems in March, 2014.
6. Data per discussion with NGK in March, 2014.
7. Value escalated at 2.3% per year from prior 2012 identified data.
8. Information added in 2014 based upon data provided by Ecoult Energy in March, 2014.
9. Information updated in 2014 based upon a review of installed project data.

Energy Storage Study - Technology Summary Matrix

Client: PacifiCorp Energy
By: HDR Engineering
7/9/2014

Pumped Storage

	Item	General Pumped Hydro Projects				
		General	Single Speed	Variable Speed	Closed Loop(1)	Open Loop(2)
General Criteria						
1	Commercial status (developmental, commercial, mature)	mature	mature	commercial	mature	mature
2	Number of plants to date (United States)	40	40	0 (10 worldwide)	18	22
3	Year of first operation (United States)	1929	1929	1990 (Japan)	1963	1929
4	Typical project lead times (years)	5 licensing 5 construction	5 licensing 5 construction	5 licensing 5 construction	< 5 licensing 5 construction	> 5 licensing 5 construction
5	Footprint or energy density (MWh/ft^2)	Varies depending upon head and reservoir size, for example, Bath County has 700 acres for 2700 MW				
6	Applicability for long-term operation- multiple hour operation (e.g., peak shaving, sustained outages)	Load shifting and peak shaving (8 hours of daytime operation w/ 12 hours of pumping), with sufficiently sized reservoirs, weekly and seasonal storage available				
7	Applicability for short-term operation- subhourly operation (e.g., power quality applications)	load following, frequency regulation, spinning reserve, for both single and variable speed. variable speed provides faster response times and finer adjustments				
8	Potential environmental/regulatory factors	vary widely from site to site. may include land use, recreation and fisheries issues	vary widely from site to site. may include land use, recreation and fisheries issues	vary widely from site to site. may include land use, recreation and fisheries issues	generally fewer impacts and shorter licensing period than open loop	generally more impacts and longer licensing period than closed loop
9	Electrical transmission considerations	proximity to transmission line can affect project economics				
10	Required size of interconnection (kV)	>230 to 500 kV preferred				
11	Vehicular access and local infrastructure considerations	projects may be in remote locations. roads, additional construction material transportation cost, and electrical transmission may be included in total project cost.				
12	Geological or topographic factors	short length of conveyance and high head create better project economics	short length of conveyance and high head create better project economics	short length of conveyance and high head create better project economics	makeup water for the reservoirs must be considered (but generally easy to overcome)	may have more fisheries and environmental considerations than a closed loop system.
13	Technology risks	tunneling, sedimentation, seismology	generating technology is proven	variable speed not implemented in US, but has been proven internationally	tunneling, seismology, makeup water for reservoirs	tunneling, sedimentation, seismology
14	Potential fatal flaws to commercial viability	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing	environmental fatal flaws, seismology, project financing
15	Staffing requirements (# full time staff members for 1000 MW facility)	15 to 25 depending on asset portfolio in region				
Performance Characteristics						
1	Range of power capacity of plant (MW)	9 - 2800	9 - 2800	85 - 600 (internationally)	28 - 2700	9 - 2000
2	Range of discharge time (hrs)	5 - 100+	5 - 100+	same capacity as single speed (NA in US)	5 - 100+	9 - 100+
3	Range of energy capacity (MWhr)	87-370,000	87-370,000	same capacity as single speed (NA in US)	247-190,000	87-370,000
4	Annual forced outage rate (% of time)	0-3%				
5	Expected life of generating equipment (years)	20+				
6	Expected life of project (years)	50+				
7	Expected life of project (number of cycles)	>10 cycles/day/year for 50 years				
8	Parasitic load (for a 1000 MW plant) (MWhr/year)	5 MW				
9	Turn around efficiency (AC-AC efficiency) (%)	75 - 80%	75 - 80%	80 - 82%	75 - 80%	75 - 80%
Basis for Cost Estimates (costs are expressed in 2014 US dollars)						
1	Range of capital cost ($ per kW)	$1,700-$2,500 per kW[4]				
2	Range of operations and maintenance cost ($ per kW-yr)	$6.2-$43.3[5] ($12.7 - $15.7 based upon Swan Lake, JD Pool, and Black Canyon estimates[4])				
3	Biannual Outage Costs (for a 1,000 MW project)	$262,000[5]				
4	Major Maintence Costs (for a 1,000 MW project)	$6,280,000[5]				
5	Replacement frequency (years)	20				

1. Closed loop system- A pumped storage system in which the upper and lower reservoirs are connected by a relatively short water conveyance system and the dams are not on a main-stem river.
2. Open loop system- A pumped storage system in which one or more of the dams are on a main-stem river.
3. O&M Cost/MW based on largest and smallest pumped storage plants in US
4. Values adjusted in accordance with 2014 assessment of Swan Lake, JD Pool, and Black Canyon projects.
5. Values escalated at 2.3% per year from 2012 values provided in 2011 study.

Energy Storage Study - Technology Summary Matrix

Client: PacifiCorp Energy

By: HDR Engineering

7/9/2014

Item		Potential Projects within PacifiCorp Region		
		Swan Lake North	Black Canyon	JD Pool
General Criteria				
1	Location	OR	WY	WA
2	FERC licensing status	filing progress reports	filing progress reports	filing progress reports
3	Project type (closed/open loop)	closed	closed	closed
4	Upper reservoir Elevation (msl)	5,499	7,360	2,710
5	Lower reservoir Elevation (msl)	4,156	6,359	705
6	Approx. static head (ft)	1,188-1,318	1,001	1,900-2,100
7	Estimated conduit length (ft)	6,266	7,000	8,000
8	Conduit length (L)/static head (H)	4.5	7.0	4.3
9	Upper reservoir usable volume (acre-ft)	5,837	6,300	11,000
10	Lower reservoir usable volume (acre-ft)	6,000	1,016,717	13,000
11	Existing upper or lower pool?	no	yes- lower	no
12	Source of water	off-system groundwater, agreement in place for fill and makeup	Existing Seminoe Reservoir - water rights to be purchased	Off river withdrawal from existing pumps. Water agreement is by DOE
13	Potential environmental/regulatory factors	BLM lands, archeological resources	BLM lands	awaiting studies
14	Upper reservoir empoundments	6560 ft long. 11 ft high, compacted rockfull with asphalt concreete face	8,720 ft long, 45 ft high earthen ring or CFRD	8,610 ft long, 270 ft high earthen dam with clay core
15	Lower reservoir empoundments	5,245 ft long 100 ft high compacted rockfull with asphalt concreete face	existing, 530 ft long, 295 ft high concrete arch	5,870 ft long, 295 ft high earthen dam with clay core
16	Vehicular access and local infrastructure considerations	access roads not discussed	no new roads required	access roads not discussed
17	Geological or topographic factors	unknown	Major intersecting fault lines under Seminoe Dam	unknown
18	Distance to electrical transmission interconnection (mi)	30	1	8
19	Required size of interconnection (kV)	230	230	230
Performance Characteristics				
1	Energy storage (MWh)	5,280	5,550	16,500
2	Assumed hours of storage (hrs)	8.8	9.2	11
3	Resulting installed capacity (MW)	600	600	1,500

NOTE: Project specific Data has been provided by Gridflex, EDF and Klikitat PUD. Where supplemental information was not provided, information from preliminary permit applications was used.

Energy Storage Study - Technology Summary Matrix
Client: PacifiCorp Energy
By: HDR Engineering
July 9, 2014

Batteries

	Item	Batteries					
		Lithium Ion	Sodium Sulfur	Flow - Vanadium Redox	Dry Cell	Flow - Zinc Bromine	Advanced Lead-Acid
	General Criteria						
1	Manufacturer / technology[1]	A123 Systems, Inc. / Smart Grid Stabilization System	NGK Insulators, Ltd / PS and PQ modules	Prudent Energy / VRB-ESS MW-class	Xtreme Power, Inc. / DPR15-100C	Premium Power Corporation / TransFlow 2000 (other turnkey system under development is ZincFlow Stationary 2- and 3.4-MW blocks)	Ecoult Energy Storage Solution/ East Penn.
2	Turnkey system?	Yes	Yes	Yes	Yes	Yes	Yes
3	Power Conversion System (PCS) manufacturer	ABB, Dynapower, Parker Hannifin, Satcon	ABB, S&C	ABB, Converteam (now GE), Dynapower, Satcon	Dynapower, Parker Hannifin	Sanmina-SCI	UltraBattery Energy Resource (UBer)
4	Commercial status (developmental, commercial, mature)	commercial	mature	commercial	developmental	commercial	commercial
5	Number of installations to date	Since 2009, seven projects in the US with 69 MW / 47.5 MWh. Largest projects include 20 MW / 5 MWh in Johnson City, NY and 8 MW / 32 MWh in Tehachapi, CA. Currently developing a 32 MW / 8MWh system in Oro Mountain, WV.	First project 0.500 MW for TEPCO Kawasaki substation in 1995. Now, over 120 international projects with 190 MW and 1,300 MWh -- largest project 12 MW / 86.4 MWh Honda facility Japan in 2008. As of 2010, six projects in the US with 14.75 MW / 73.2 MWh -- largest project 4 MW / 24 MWh in Presidio, TX (2010). Five projects totaling 7.9 MW / 23.2 MWh programmed for 2011 throughout the US.	First US project with PacifiCorp in Castle Valley, UT with 0.250 MW / 2 MWh in 2004. In 2009, 0.600 MW / 3.6 MWh system installed at Gills Onion plant, CA. Two other projects in development in CA, with combined nameplate capacity of 2.2 MW. In March 2011, 0.500 MW / 1 MWh renewable integration test facility installed in Zhangbei, China.	0.5 MW / 0.1 MWh test facility in Antartica for microgrid peak shaving completed in 2006. 1.5 MW / 1 MWh test facility in Maui, HI for renewable integration completed in 2009.	6.9 MW / 17.2 MWh installed to date in the US. Five recent ARRA projects, two in CA and three in MA, installed / under development rated at 0.5 MW / 3 MWh each.	3 MW scale demonstrations to date with a fourth commissioned, notable projects include 3 MW frequency regulation of PJM grid in Pennsylvania and a 3 MW micro-grid application that allows an island of 1,500 people to utilize 100% renewable energy
6	Year of first installation	2009	1995	2004	2009	unknown- 2000's	unknown, 2010-2011
7	Typical project lead times (years)	1 yr	1 yr	1 yr	1 yr	1 yr	1yr
8	Footprint (ft^2 per MWh)	TBD	TBD	TBD	TBD	TBD	TBD
9	Applicability for long-term operation- Multiple Hour Operation (e.g., peak shaving, sustained outages)	Renewables integration	Peak shaving, renewables integration, generator support	Peak shaving, renewables integration	Renewables integration	Peak shaving, renewable integration	Renewables integration
10	Applicability for short-term operation- Subhourly operation (e.g., power quality applications)	Power quality, substation support	Power quality, UPS	Power quality, UPS	Peak shaving, power quality	Power quality, UPS	Power quality, UPS
11	Potential environmental/regulatory factors	Electrolytes may vent, ignite and produce sparks at high temperatures (>150C) or when damaged	Performance is temperature dependent. Potentially, electrolytes are hazmat-classified and flammable.	Performance is temperature dependent. Potentially, electrolytes are hazmat-classified and flammable.	Non-hazmat and recyclable.	Non-hazmat, 100% disposable or recyclable.	Non-hazmat, recyclable
12	Electrical transmission considerations	None identified	None identified	None identified	None identified	None identified	None identified
13	Vehicular access and local infrastructure considerations	Requires vehicle access. Requires auxiliary ventilation and mechanical cooling systems (i.e. air conditioning systems). Requires radio or phone communication infrastructure	Requires vehicle access. Requires auxiliary 7.2 kW block heaters (208V) required to keep cells at 300C when not in operation. Requires radio or phone communication infrastructure.	Requires building structure to house equipment. Requires vehicle access. Requiers radio or phone communication infrastrucutre.	Requires vehicle access. Requires auxiliary ventilation. Requires radio or phone communication infrastructure.	Requires vehicle access. Requires auxiliary ventilation and mechanical cooling systems (i.e. air conditioning systems). Requires radio or phone communication infrastructure.	Requires vehicle access. Requires radio or phone communication infrastructure.
18	Technology risks - failure modes	Possible failure with power electronics module. Aggressive discharge rates may overheat batteries.	Sealing deteriorates after 15 years	Plastic containers	Improper terminations possible	Polyethylene plastic substrates	No catastrophic failure modes.
19	Staffing requirements (# full time staff members)	Monitored remotely. Occassional maintenance and site visits.	Monitored remotely. Occassional maintenance and site visits.	Monitored remotely. Occassional maintenance and site visits.	Monitored remotely. Occassional maintenance and site visits.	Monitored remotely. Occassional maintenance and site visits.	Monitored remotely. Occassional maintenance and site visits.
	Performance Characteristics						
1	Range of power capacity (MW)	1 - 32	1 - 12	0.250 - 10	1.5 - 19.5	0.5 - 20	1 - 18
2	Base unit energy (MWh)	0.023 MWh	1 cell is 0.000142 MWh	1 tank is 0.250 MWh	1 cell is 0.001 MWh	1 trailer is 2.8 MWh	20' shipping container is 0.25 - 0.75 MWh depending on application
3	Base module rating (MW)	0.12	0.05	0.25	0.001	1 trailer is 0.500 MW	0.25
4	Range of discharge time (hrs)	20 milisec - 15 min. (1 hr for High Energy System)	10 sec - 7.2 hr. Typical ramp rate 30 min.	40 milisec - 8 hr.	unknown	1 hr - 5.5 hr. Ramp rate is 7 milisec.	unknown, Ecoult focuses on high power/energy ratio
5	Range of energy capacity (MWh)	Variable depending on depth of discharge (DOD)					
6	Charge-to-discharge ratio	unknown	1.4:1	1.5:1	1:1	1:1	unkown
7	Annual forced outage rate (% of time)	3%	0.3%	2%	2%	0.01	2%
8	At 100% depth-of-discharge (DOD)	100,000 cycles before capacity falls under 75%	2,500 cycles	Indefinite[2]	1,000 cycles	Indefinite[2]	Approximately 9,000
9	At 80% DOD	unknown	5,000 cycles		150,000 cycles		unkown
10	At 2.5% DOD	1,000,000 cycles before capacity falls under 75%	unknown		unknown		unkown
11	Parasitic load	Depending on plant operation, typically 7% of energy throughput	Storage Management System (SMS) = 0.050 MW per 1 MW installed. Heater = 0.144 MW per MW (heating mode), 0.56 MW per MW (temperature maintenance mode)	General parasitic loads include PCS, VFD-controlled pumps (one each at terminal) cycling between 0.005 MW and 0.0025 MW (standby)	0.010 MW per 1 MW nameplate	Full load cooling system power draw is between 0.019 - 0.020 MW per trailer.	Dependent on application
12	Turn around efficiency (AC-AC efficiency) (%)	91%	70 - 75%	65 - 75%	>90%	60%	>90%
	Basis for Cost Estimates (costs are expressed in 2014 US dollars)						
1	Range of capital cost ($ per kW $ per kWh or as applicable)	$800 to $1,000 per kW for High Power system ($800 to $1,200 per kWh for High Energy system)[3]	$4,000 per kW[4]	Unknown capital per kW $675 per kWh[7]	$1,900 - 2,100 per kW[7]	$1500 - $2200 per kWh at assumed 6:1 energy to power ratio[5]	Approximately $1,700 per kW, highly dependent on application[6]
2	Range of operations and maintenance cost ($ per MW-yr)	Generally 4% of capital costs recurring annually	$15,700 per year[7]	unknown	unknown	$20,950 per year[7]	Generally 1-2% of capital costs, dependent on site location and application[6]
3	Warranty (yrs)	18 months from shipment or 12 months from commissioning	2 yrs	2 yrs	Cells 5 yrs. Balance of plant 2 yrs.	1 yr	lifetime management contracts offered dependent on application
4	Extended warranty (yrs)	Project-specific, generally requiring load modeling	3 yrs extension at $50,000 per MW	Project-specific, generally extendable 5 - 10 yrs at $22,000 per MW per year.	Project-specific, requires review	Project-specific, available up to 30 yrs.	lifetime management contracts offered dependent on application
5	Available in-house, contracted, maintenance service?	Yes	Yes	None	None	Yes	Yes
6	Replacement frequency (years)	Depending on plant operation, typically 7 - 10 yrs	15 yrs	Cell stacks typically 10 - 15 yrs. Balance of plant typically 25 yrs.	Powercells typically 3 times over a period of 20 yrs.	30 yrs	dependent on application, typically about 5 years

Notes:

1 HDR neither recommends nor guarantees the products or services of manufacturers listed herein. References made to aforementioned manufacturers and their products and services are strictly for analysis purposes only.

2 Theoretical limit -- at the time of writing, no data points were made available to HDR showing empirical performance of installed systems with significant number of years in service.

3 Data per discussion with A123 Systems in March, 2014.

4 Data per discussion with NGK in March, 2014.

5 Information updated in 2014 based upon a review of installed project data.

6 Information added in 2014 based upon data provided by Ecoult Energy in March, 2014.

7 Values escalated at 2.3% per year from prior 2012 identified data.

Energy Storage Study - Technology Summary Matrix

Client: PacifiCorp Energy

By: HDR Engineering

July 9, 2014

Compressed Air Energy Storage

	Item	Compressed Air Energy Storage- 6000 ft Elevation Operation
	General Criteria	
1	Commercial status (developmental, commercial, mature)	Commercial
2	Number of plants to date	2 currently operational
3	Year of first operation	1978
4	Typical project lead times (months)	24 to 28 months
5	Footprint or energy density (ft^2 per MW)	20 acres for 135 MW Block
6	Potential project locations within PacifiCorp service territory	Western Energy Hub - Delta, Utah
7	Applicability for long-term operation- multiple hour operation (e.g., peak shaving, sustained outages)	Peak shaving and Intermediate Service (8 hours of daytime operation w/ 8 hours of compression at night typical)
8	Applicability for short-term operation- subhourly operation (e.g., power quality applications)	Similar characterstics to a simple cycle gas turbine, provided compressed air is available.
9	Potential environmental/regulatory factors	Plant emissons similar to simple cycle gas turbine application. Compressors require cooling water supply (mechanical draft cooling tower required).
10	Electrical transmission considerations	Same as a simple cycle gas turbine.
11	Vehicular access and local infrastructure considerations	Same as a simple cycle gas turbine. Natural gas pipeline required.
12	Geological or topographic factors	Solution mined salt cavern, aquifer, or mined hard rock cavity (limestone mines) required.
13	Required size of interconnection (kV)	230 kV or higher
14	Technology risks	Limited suppliers available, integrity of cavern used for storage of compressed air.
15	Potential fatal flaws to commercial viability	Satisfactory Geology
16	Staffing requirements (# full time staff members for 100 MW Facility)	2 hourly, 6 salaried (15 FTE's estimated for 2x135-MW ISEP)
	Performance Characteristics	
1	Range of power capacity (MW)	100 MW +
2	Range of discharge time (hrs)	8 hours typical
3	Range of energy capacity (MWh)	800 MWh +
4	Average Annual Availability (% of time)	93%
5	Typical Plant Capacity Factor	23.7%
6	Expected life of equipment (years)	30
7	Gross Plant Output (MW), Average Ambient Day	559.4
8	Aux Power (MW), Average Ambient Day	2.80
		0.5%
9	Net Plant Output (MW), Average Ambient Day	556.6
10	Net Plant Heat Rate (btu/kWhr), Average Ambient Day	4436
11	% of Energy Recovered From Compression	83.4%
13	Net Plant On Peak Efficiency (Gas Turbine Efficiency)	76.92%
14	Complete Plant Turn around efficiency (AC-AC efficiency) (%)	64.11%
	Basis for Cost Estimates (costs are expressed in 2014 US dollars)	
1	EPC Cost ($/kW)	$1,200 - $1,400 per kW
2	Total Project Cost including Caverns ($/kW)	$2,000 - $2,300 per kW
4	Cost to Solution Mine Salt Caverns	$68 MM
5	Estimated fixed operations and maintenance cost ($ per kW)	$18.78
7	Estimated variable O&M cost (excluding fuel & electric costs) ($ per MWH)	$2.28

Notes

1 Plant performance is new and clean.

2 Plant performance and costs at 6000 ft assumes identical power generation equipment and cavern storage capacity and but larger compressors than that used at sea level.

3 Schedule assumes that the cavern geology project has already been identified and confirmed.

APPENDIX B – PUMPED STORAGE DATA

PacifiCorp
Energy Storage Study Update
Pumped Storage Developer Data Request
March 2014

- **CONTACT INFORMATION**

1	Legal corporate name	Klickitat County PUD
2	City, state, and zip code	Goldendale WA. 98620
3	Type of project business (corporation, LLC, partnership, other)	PUD
4	Primary contact	
A	Name	Randy Knowles
B	Title	Board Member
C	Phone number	509 493 2052 cell 509 637 3132
	E-mail address	mrno@gorge.net

- **PROJECT INFORMATION**

1	Project name	John Day Pool	
2	Project location	Klickit County WA.	
3	Project description		
		Document attached? No	
4	Layout drawings and figures	Document attached? No	
5	Energy storage	MWh	
6	Assumed hours of storage	11 hrs	
7	Resulting installed capacity	1500 MW	
8	Have system integration studies been performed in PacifiCorp's service area for how your project would participate in that market?		
	No	Document attached? No	
9	Gross head	2400 ft	
10	Maximum head	2400 ft	
12	Minimum head	2200 ft	
13	Maximum upper reservoir elevation	msl	
14	Minimum upper reservoir elevation	msl	
15	Maximum power reservoir elevation	msl	
16	Minimum lower reservoir elevation	msl	

17	Upper reservoir usable storage volume	11,000 Acre-ft	
18	Lower reservoir usable storage volume	13,000 Acre-ft	

19	Dam		
A	Existing upper or lower pool?		no
B	Upper reservoir empoundment		yes
	Dam type	Non-dim	
	Dam length	ft	awaits engineering / for specific useable data
	Dam height	ft	awaits engineering
C	Lower reservoir empoundment		
	Dam type	Non-dim	
	Dam length	ft	awaits engineering
	Dam height	ft	awaits engineering

20	Water conveyance description						
A	Intake type (horizontal/vertical)	awaits engineering					
B	Head race tunnel	Number		Length		Diameter	
C	Penstocks	Number		Length		Diameter	
D	Draft tubes	Number		Length		Diameter	
E	Tailrace tunnel	Number		Length		Diameter	
F	Has a hydraulic transient study been completed?	No	Document attached? Yes No				
G	Is surge protection required?	Yes					

21	Powerhouse		
A	Powerhouse description	awaits engineeing/ for specific useable data	
B	Powerhouse dimensions	ft	
C	Above ground?	Yes No	
D	Separate transformer cavern	Yes No	

22	Prime mover description		
A	Number of units	Non-dim	
B	Unit type	Reversible pump-turbine generator-motor	
		Conventional pump	
		Conventional Pelton	
		Conventional Francis	
		Other (ex. hydraulic short circuit)	
C	Variable speed units?	Yes	
D	Unit operating range (pump)	MW	

E	Unit operating range (generating)	MW	
F	Rated flow (generate only)	cfs	
G	Rated head (generate only)	cfs	
H	Rated head	ft	
I	Unit centerline setting (with respect to minimum tailwater)	ft	
J	Runner/impeller diameter	ft	
K	Unit cycle efficiency	%	
23	Transmission		
A	Voltage of the existing transmission line	kV	
B	Voltage of the new transmission line	kV	
C	Length of transmission from plant to interconnection point	ft	Head of DC intertie 8 miles distant. Possible conn based upon studies
D	Owner if existing transmission line	Bonneville Power	

- **PROJECT ENGINEERING STATUS**

1	What are your strategies to advance the project under the preliminary permit timeline?	Seeking parterning arrangements		
2	What is the level of project engineering definition? (see Attachment A, AACE Cost Estimate Classifications)			
3	Level of cost estimates performed to date (see Attachment A, AACE Cost Estimate Classifications)			
4	Engineering studies completed to date, provide copies of studies	Concept yes		
		Pre-feasibility		
		Feasibility		
		Detailed	% complete	
		Document attached? No		
5	What level of geotechnical exploration has been conducted at site?	preliminary for lower impoundment		
6	What level of transmission/interconnection studies have been conducted to date?	preliminary		
7	What level of unit configuration and optimization studies have been completed to date?	conceptual		
8	Project boundary description and acquisition status (including transmission corridor)			
		Document attached? Yes		
9	Type of land in project boundary. Private single owner	National forest		
		National landscape conservation system		
		Recreation management area		

		Research natural area
		Wild and scenic river
		Wilderness area
		Critical habitat
10	Consultation status	
		Document attached? no

- **PROJECT REGULATORY STATUS**

1	Preliminary permit issued?	Yes No If yes, when and what is Project number? P-13333-001
2	If yes, what licensing process was selected?	ILP TLP ALP To be determined
3	If yes, what regulatory steps have been taken to-date? (e.x., PAD filed, joint meeting held)	
4	If no, has preliminary permit application been filed?	Yes No
5	If yes, when?	
6	Source of water (initial fill and makeup) (including any water rights issues)	Off river withdrawal from existing pumps/ Water is by agreement with DOE allowed for use without further review
7	Have affected resources been identified?	Yes
	Aquatic resources – fish, marcoinvertebrates, mussels, habitat	Closed loop system/ unlikely
	Botanical resources, including wetlands	None exist on site
	Historical/cultural resources (including tribal resources)	awaiting studies
	Wildlife, including avian species, and reptiles and amphibians	awaiting studies
	Rare, threatened, and endangered species	awaiting studies
	Water quality	N/A
	Recreation	N/A
	Aesthetics	
7	Have study plans been developed?	No If yes, please list.
9	Have agencies and other stakeholders had opportunity to review study plans?	No If yes, what, if any, areas of disagreement have emerged?
10	Consultation with resource agencies and stakeholders to date (please list groups)	
11	Any environmental, regulatory, and technical studies or research completed? (please list)	
		Document attached? No

- **PROJECT COST AND REVENUE ESTIMATES**

1	Cost		
A	Direct Capital cost	$	
B	Engineering	$	
C	Construction management	$	
D	Licensing	$	
E	Contingency	$	
F	Financing	$	
G	Total project cost estimate	$	
H	Annual O&M cost ($/MWH)	$/MWh	
I	Draw schedule (total cost by year or spend plan)		
J	Material takeoffs and cost estimate	Document attached? Yes No	
2	Revenue		
A	Have you conducted a power market study?	yes	
B	Have you conducted a renewable integration study	yes	
C	Expected annual revenue	$	
D	Have you conducted benefit cost analysis?	yes	

- **PROJECT SCHEDULE**

1	Project development and construction schedules	Provide an overall project development and construction schedule indicating timelines for development, permitting, engineering, procurement, and construction.
		Document attached? No
2	Projected commercial operation date per unit	

- **DEVELOPER INFORMATION**

1	Financial statements	Provide annual reports. If not a public entity, provide audited financial statements for the past three years including balance sheet, income statement, cash flow statement, and accompanying related notes. A separate submittal must be completed for each member of a partnership.	
		Document attached? No	
2	Company net worth	Provide Tangible Net Worth as of the last audited fiscal year end. Tangible net worth shall be defined as the total assets less the sum of intangible assets, goodwill and total liabilities.	
		Document attached? No	
3	Bankruptcy status	Has the company or your predecessor company declared bankruptcy in the past 5 years? If answer is yes, describe the situation and how it affects the company's ability to meet its credit obligations.	
		No	Document attached? Yes No

4	Company solvency	Are there any pending bankruptcies or other similar state or federal proceedings, outstanding judgments, or pending claims or lawsuits that could affect the solvency of the company? If answer is yes, describe the situation and how it affects the company's ability to meet its credit obligations.	
		No	Document attached? No
5	Power industry resume and assets	Identify any and all interests in power generation facilities with an identification of technologies, unit sizes, and project name.	
	Project Name	Ownership Percentage	Project Size (MW)
	Mcnary Hydro	50%	10 MW
	HW Hill LFG to energy	100%	37 installed MW
	White creek wind	13%	204 MW

- **PROJECT FINANCING AND OWNERSHIP DESCRIPTION**

1	Project financing approach		To be determind
2	Project ownership structure		To be determined
3	Existing power purchase and offtaker agreements		
4	Debt/equity split (if applicable)	(% / %)	
5	Other subsidies/incentives		
	Type		
	Value	$	
	Status		
	Type		
	Value	$	
	Status		
	Type		
	Value	$	
	Status		
6	Contracting methodology		

Attachments:

- AACE Class 1 through 5 Cost Estimate Classifications

PacifiCorp
Energy Storage Study Update
Pumped Storage Developer Data Request
March 2014

A. CONTACT INFORMATION

1	Legal corporate name	EDF Renewable Energy Inc.
2	City, state, and zip code	San Diego, CA, 92128
3	Type of project business (corporation, LLC, partnership, other)	Renewable Energy Corporation
4	Primary contact	
A	Name	Joe Eberhardt
B	Title	Director, Hydropower – West Region
C	Phone number	503-889-3838
D	E-mail address	Joe.eberhardt@edf-re.com

B. PROJECT INFORMATION

1	Project name	Swan Lake Pumped Storage Hydropower Project	
2	Project location	Approximately 11 miles NE of Klamath Falls, Oregon	
3	Project description	The Swan Lake North Pumped Storage Hydropower Project will be built in Klamath County, approximately 11 miles northeast of Klamath Falls. This closed-loop system would require two new dams and reservoirs. Approximately 12,747 acre-feet of water will be exchanged between the two reservoirs on daily basis. Using up to four variable-speed, reversible pump-turbine units, the project will have the capacity to deliver 600 megawatts of electricity for up to 9 hours a day. Approximately 30 miles of transmission line will be constructed to connect the project to the existing California-Oregon intertie Paci #2 Line.	
		Document attached? Yes ☐ No ☒	
4	Layout drawings and figures	Document attached? Yes ☒ No ☐ Preliminary Base Case	
5	Energy storage	MWh	5,280 MWh
6	Assumed hours of storage	hrs	8.8
7	Resulting installed capacity	MW	600
8	Have system integration studies been performed in PacifiCorp's service area for how your project would participate in that market?		
	Yes ☒ No ☐	Document attached? Yes ☐ No ☒ Study is currently ongoing	
9	Gross head	ft	1,275
10	Maximum head	ft	1,318
12	Minimum head	ft	1,188
13	Maximum upper reservoir elevation	msl	5,499
14	Minimum upper reservoir elevation	msl	5,424

15	Maximum power reservoir elevation	msl	5490.5
16	Minimum lower reservoir elevation	msl	4,156
17	Upper reservoir usable storage volume	Acre-ft	5837
18	Lower reservoir usable storage volume	Acre-ft	6,000

19	Dam		
A	Existing upper or lower pool?		No
B	Upper reservoir empoundment		
	Dam type	Non-dim	Compacted Rockfill with Asphalt Concrete Face
	Dam length	ft	6,560
	Dam height	ft	111
C	Lower reservoir empoundment		
	Dam type	Non-dim	Compacted Rockfill with Asphalt Concrete Face
	Dam length	ft	5,245
	Dam height	ft	100

20	Water conveyance description						
A	Intake type (horizontal/vertical)	See attached drawings for Information					
B	Head race tunnel	Number		Length		Diameter	
C	Penstocks	Number		Length		Diameter	
D	Draft tubes	Number		Length		Diameter	
E	Tailrace tunnel	Number		Length		Diameter	
F	Has a hydraulic transient study been completed?	Yes ☒ No ☐	Document attached? Yes ☐ No ☒				
G	Is surge protection required?	Yes ☐ No ☒					

21	Powerhouse		
A	Powerhouse description	Power house located at the foot of an escarpment between two scree fields, composed of 4 shafts of 220 feet long and around 60 feet diameter. The power house is one unique man-made cavern including transformers and electronic devices.	
B	Powerhouse dimensions	ft	
C	Above ground?	Yes ☐ No ☒	
D	Separate transformer cavern	Yes ☐ No ☒	

22	Prime mover description		
A	Number of units	Non-dim	4 reversible units of 150MW each – Variable speed equipment
B	Unit type	Reversible pump-turbine generator-motor ☒	
		Conventional pump ☐	
		Conventional Pelton ☐	
		Conventional Francis ☐	
		Other (ex. hydraulic short circuit) ☐	
C	Variable speed units?	Yes ☒ No ☐	
D	Unit operating range (pump)	MW	Minimum input power of 117-136 MW at low speed and rapidly ramping to 150 MW at high speed as necessary to support grid operations.
E	Unit operating range (generating)	MW	Minimum of 75 to a maximum of 135 - 150 MW (depending on the starting head differential),
F	Rated flow (generate only)	cfs	
G	Rated head (generate only)	cfs	
H	Rated head	ft	
I	Unit centerline setting (with respect to minimum tailwater)	ft	
J	Runner/impeller diameter	ft	
K	Unit cycle efficiency	%	

23	Transmission		
A	Voltage of the existing transmission line	kV	500
B	Voltage of the new transmission line	kV	230
C	Length of transmission from plant to interconnection point	ft	30 miles
D	Owner if existing transmission line	PacifiCorp - Malin-Round Mountain line (shared with PG&E which owns the southern line segment)	

C. PROJECT ENGINEERING STATUS

1	What are your strategies to advance the project under the preliminary permit timeline?	Main strategy is to establish an anchor contracted off taker or equity partner, and then continue to de-risk the project development.
2	What is the level of project engineering definition? (see Attachment A, AACE Cost Estimate Classifications)	AACE Cost Estimate Class 4
3	Level of cost estimates performed to date (see Attachment A, AACE Cost Estimate Classifications)	AACE Cost Estimate Class 4

<table>
<tr><td rowspan="5">4</td><td rowspan="5">Engineering studies completed to date, provide copies of studies</td><td colspan="3">Concept ☐</td></tr>
<tr><td colspan="3">Pre-feasibility ☐</td></tr>
<tr><td colspan="3">Feasibility ☐</td></tr>
<tr><td>Detailed ☐</td><td>% complete</td><td></td></tr>
<tr><td colspan="3">Document attached? Yes ☐ No ☐</td></tr>
<tr><td>5</td><td>What level of geotechnical exploration has been conducted at site?</td><td colspan="3">We have performed a feasibility-level geotechnical and geophysical investigation of the project site to determine the ability of the underlying soils and rock to support the proposed dams and structures and to facilitate ongoing permitting. The feasibility-level investigation has been divided into two phases. The first phase of the investigation focuses on the soils of the Swan Lake basin and their ability to support the proposed development. The primary objective of the investigation was to evaluate the susceptibility of the soils to liquefaction under seismic loading.</td></tr>
<tr><td>6</td><td>What level of transmission/interconnection studies have been conducted to date?</td><td colspan="3">TANC – Feasibility Study that investigated 1000 MW interconnection on its 500 kV Captain Jack-Olinda line with preliminary conclusion that only 400 MW could be interconnected w/o requiring additional transmission circuits on the Intertie. Withdrew interconnection request from TANC.

PacifiCorp – Feasibility Study that investigated 600 MW interconnection on its northern line segment on the 500 kV line #2 Malin-Round Mountain line (shared with PG&E who have southern line segment), just south of the Malin substation. Preliminary conclusion was that 600 MW could be interconnected w/o requiring additional transmission circuits on the Intertie. Currently preparing for the Impact Study which will take 365 days to complete and PacifiCorp will include BPA as a study partner. Other Affected Systems will be asked to review the results.</td></tr>
<tr><td>7</td><td>What level of unit configuration and optimization studies have been completed to date?</td><td colspan="3">We have had our parent company EDF, with its broad pumped storage expertise, work on both 1) the most probable layout based on calculation of the transient hydraulic</td></tr>
</table>

		conditions in both high-pressure and low-pressure circuits and 2) the capital cost based on existing construction across the world that EDF is involved with currently, as well as the historical information on the many pumped storage projects that EDF has built. This was then adjusted for the US market. Additional ongoing geo-tech testing is needed to validate assumptions.
8	Project boundary description and acquisition status (including transmission corridor)	Draft License Application publicly available on FERC website
		Document attached? Yes ☐ No ☒
9	Type of land in project boundary	National forest ☒
		National landscape conservation system ☐
		Recreation management area ☐
		Research natural area ☐
		Wild and scenic river ☐
		Wilderness area ☐
		Critical habitat ☐
10	Consultation status	
		Document attached? Yes ☐ No ☐

D. PROJECT REGULATORY STATUS

1	Preliminary permit issued?	Yes ☒ No ☐ If yes, when and what is Project number? 11/16/2012; #13318
2	If yes, what licensing process was selected?	ILP ☐ TLP ☒ ALP ☐
3	If yes, what regulatory steps have been taken to-date? (e.x., PAD filed, joint meeting held)	This preliminary permit succeeds a prior preliminary permit for the project; NOI/ PAD, with election to use TLP, filed in June 2010; granted August 6, 2010; substantial agency consultation held and studies completed; public meetings held; Draft License Application filed December 16, 2011; final License Application drafted but revisions currently pending upon completion of supplemental geotechnical studies and corresponding engineering revisions in the Final License Application.
4	If no, has preliminary permit application been filed?	Yes ☐ No ☐ N/A
5	If yes, when?	N/A
6	Source of water (initial fill and makeup) (including any water rights issues)	Groundwater; agreement in place covering water needed for both initial fill and makeup water. No water rights issues for either fill or ongoing operations.

7	Have affected resources been identified?	Yes
	Aquatic resources – fish, marcoinvertebrates, mussels, habitat	Yes
	Botanical resources, including wetlands	Yes
	Historical/cultural resources (including tribal resources)	Yes
	Wildlife, including avian species, and reptiles and amphibians	Yes
	Rare, threatened, and endangered species	Yes
	Water quality	Yes
	Recreation	Yes
	Aesthetics	Yes
7	Have study plans been developed?	Yes ☒ No ☐ If yes, please list.
9	Have agencies and other stakeholders had opportunity to review study plans?	Yes ☒ No ☐ If yes, what, if any, areas of disagreement have emerged?
10	Consultation with resource agencies and stakeholders to date (please list groups)	Consultation has been documented at every stage with all affected agencies and stakeholders; please see Draft License Application (DLA), filed in December 2011 and available for download.
11	Any environmental, regulatory, and technical studies or research completed? (please list)	All required studies completed; see DLA Exhibit E for study descriptions and results.
		Document attached? Yes ☐ No ☒

E. PROJECT COST AND REVENUE ESTIMATES

1	Cost(000) $2011		
A	Direct Capital cost	$	1,102,000
B	Engineering and management	$	110,000
C	Construction management	$	
D	Licensing, Marketing, Land and Water Rights	$	31,500
E	Contingency	$	159,000
F	Financing	$	TBD; overnight basis stated
G	Total project cost estimate	$	1,402,000, overnight basis
H	Annual O&M cost ($/MWH)	$/kW-yr	Fixed 4.57; variable $4.30/MWh
I	Draw schedule (total cost by year or spend plan)		
J	Material takeoffs and cost estimate	Document attached? Yes ☐ No ☒	
2	Revenue		
A	Have you conducted a power market study?	yes	
B	Have you conducted a renewable integration study	no	
C	Expected annual revenue	$	(proprietary)
D	Have you conducted benefit cost analysis?	yes	

F. PROJECT SCHEDULE, PRELIMINARY

1	Project development and construction schedules	Provide an overall project development and construction schedule indicating timelines for development, permitting, engineering, procurement, and construction. 2014 Q2 geotech supplemental studies 2014 Q3 FLA revisions 2014 Q4 FLA submitted 2016 Q2 FERC EIS available 2016 Q4 FERC license granted, Field investigations commenced to educate Preliminary design and class 3 cost estimate 2017 Q1 Preliminary design and class 3 cost estimate commenced 2017 Q3 Field investigations to educate detailed design 2017 Q4 Detailed design and class 1 cost estimate commenced 2018 Q2 Completion of bid documents; EPC long lead procurement 2018 Q4 Financial close and EPC NTP 2022 Q2 COD
		Document attached? Yes ☐ No ☒
2	Projected commercial operation date per unit	

G. DEVELOPER INFORMATION

1	Financial statements	Provide annual reports. If not a public entity, provide audited financial statements for the past three years including balance sheet, income statement, cash flow statement, and accompanying related notes. A separate submittal must be completed for each member of a partnership. (Financial Statements of immediate parent and ultimate parent company are available online.)	
		Document attached? Yes ☐ No ☒	
2	Company net worth	Provide Tangible Net Worth as of the last audited fiscal year end. Tangible net worth shall be defined as the total assets less the sum of intangible assets, goodwill and total liabilities. (available online)	
		Document attached? Yes ☐ No ☒	
3	Bankruptcy status	Has the company or your predecessor company declared bankruptcy in the past 5 years? If answer is yes, describe the situation and how it affects the company's ability to meet its credit obligations.	
		Yes ☐ No ☒	Document attached? Yes ☐ No ☒

4	Company solvency	Are there any pending bankruptcies or other similar state or federal proceedings, outstanding judgments, or pending claims or lawsuits that could affect the solvency of the company? If answer is yes, describe the situation and how it affects the company's ability to meet its credit obligations.	
		Yes ☐ No ☒	Document attached? Yes ☐ No ☒
5	Power industry resume and assets	Identify any and all interests in power generation facilities with an identification of technologies, unit sizes, and project name.	
	Project Name	Ownership Percentage	Project Size (MW)
	(Numerous, available online; 61 wind;27 solar;3 biogas;2 biomass;37 O&M)		

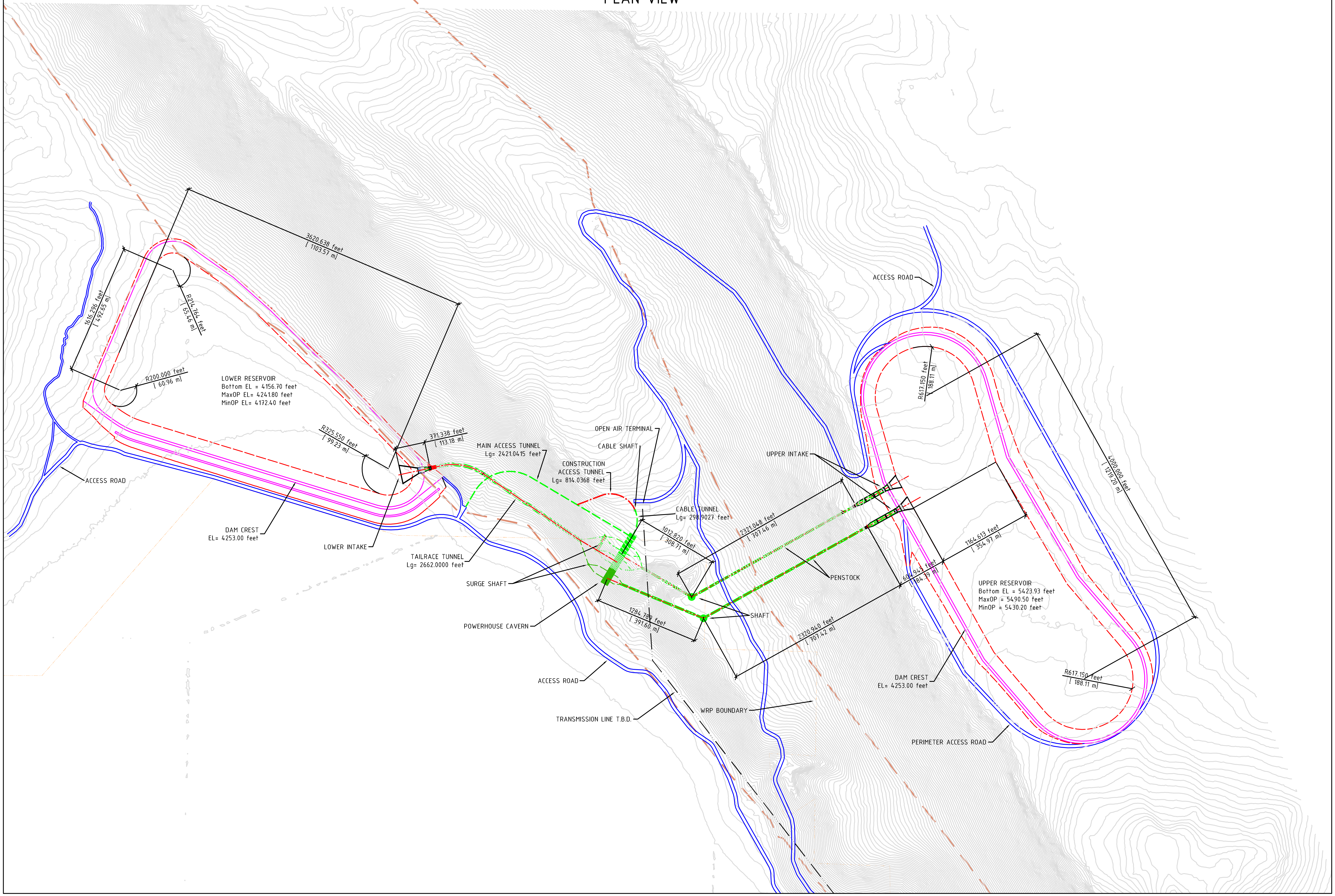
H. PROJECT FINANCING AND OWNERSHIP DESCRIPTION

1	Project financing approach		Major equity contribution – We assume minimum debt.
2	Project ownership structure		We are considering all possible structures at this point from a Design build sell to Joint Venture to outright ownership by an IPP with an offtaker agreement or agreements.
3	Existing power purchase and offtaker agreements		No existing PPA or Offtaker agreement at this point.
4	Debt/equity split (if applicable)	(% / %)	0/100% at this point
5	Other subsidies/incentives	TDB	
	Type		
	Value	$	
	Status		
	Type		
	Value	$	
	Status		
	Type		
	Value	$	
	Status		
6	Contracting methodology		

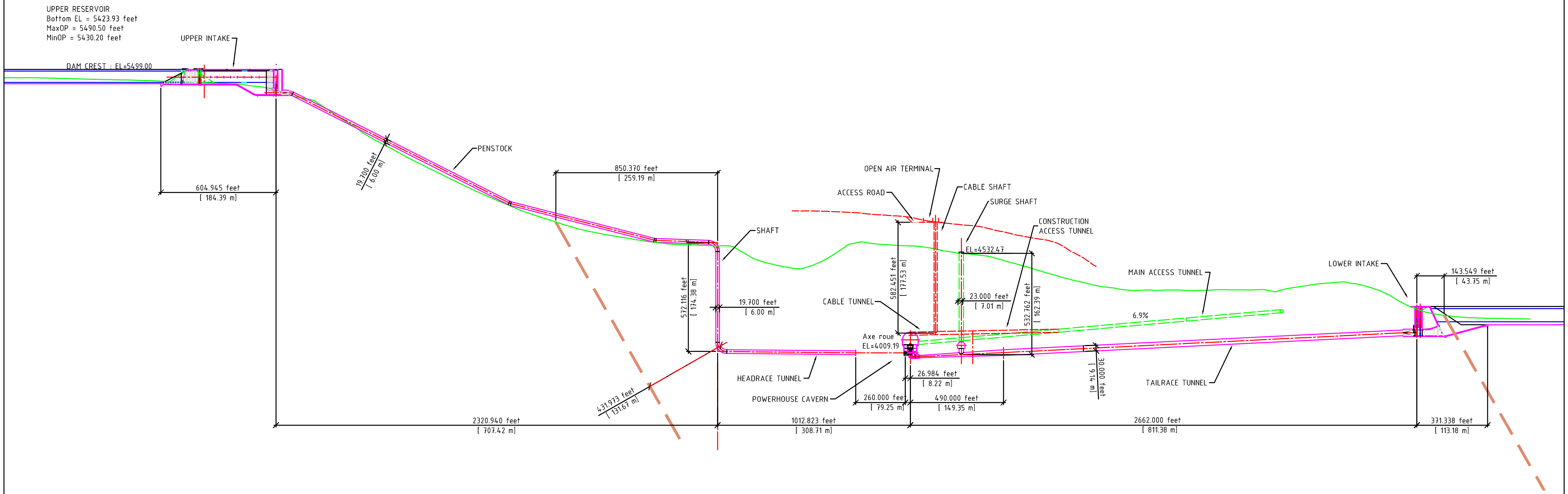
Attachments:

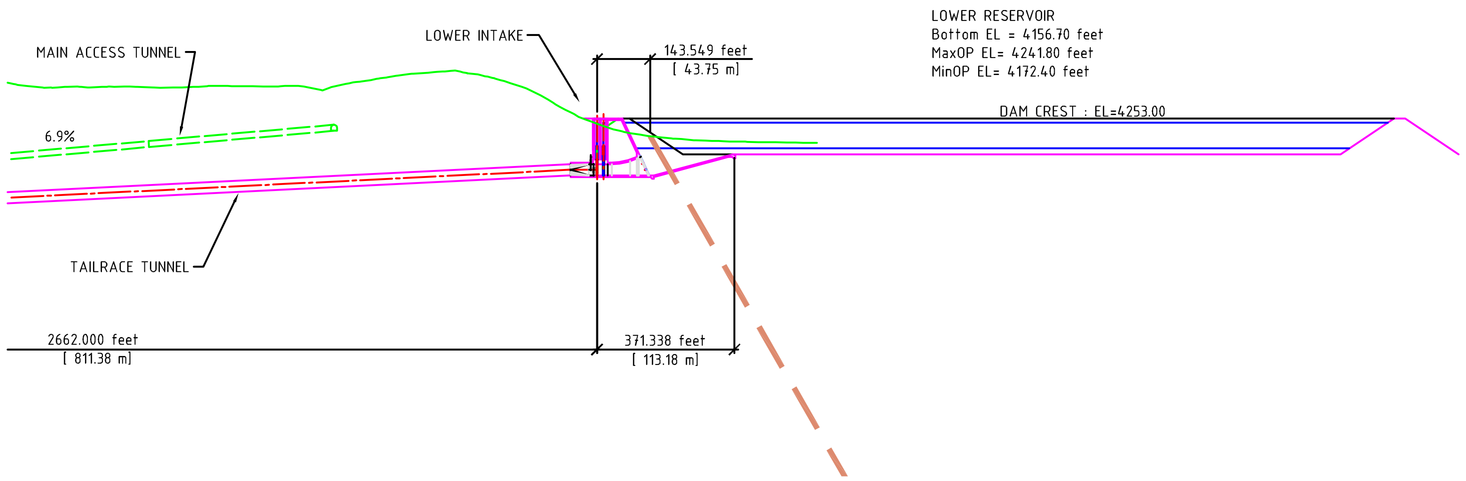
A. AACE Class 1 through 5 Cost Estimate Classifications

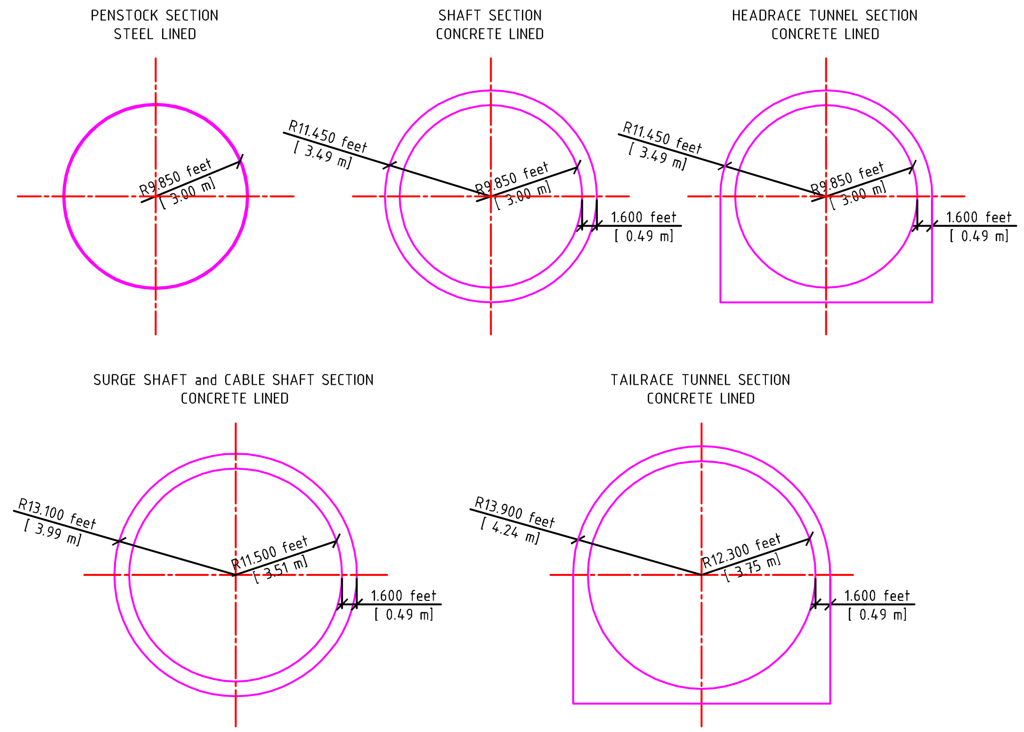
BASE CASE – HYBRID WATER CONVEYANCE
PLAN VIEW



BASE CASE – HYBRID WATER CONVEYANCE PROFILE







PacifiCorp
Energy Storage Study Update
Pumped Storage Developer Data Request
March 2014

A. CONTACT INFORMATION

1	Legal corporate name	Gridflex Energy, LLC / Black Canyon Hydro, LLC
2	City, state, and zip code	Boise, ID 83702
3	Type of project business (corporation, LLC, partnership, other)	LLC
4	Primary contact	
A	Name	Matthew Shapiro
B	Title	Chief Executive Officer
C	Phone number	(208) 246-9925
D	E-mail address	mshapiro@gridflexenergy.com

B. PROJECT INFORMATION

1	Project name	Black Canyon Pumped Storage	
2	Project location	Carbon County, Wyoming	
3	Project description	Pumped storage project with existing reservoir	
		Document attached? Yes ☐Y No ☐	
4	Layout drawings and figures	Document attached? Yes ☐Y No ☐	
5	Energy storage	MWh	5550 (Note: This is for only one of the two potential projects at the same site, involving the "East" upper reservoir + existing Seminoe Reservoir; other alternatives include a second upper reservoir site and separate or dual use of Kortes & Seminoe Reservoirs)
6	Assumed hours of storage	hrs	9.2
7	Resulting installed capacity	MW	600
8	Have system integration studies been performed in PacifiCorp's service area for how your project would participate in that market?		
	Yes ☐ No ☐N	Document attached? Yes ☐ No ☐	
9	Gross head	ft	
10	Maximum head	ft	1,063
12	Minimum head	ft	936
13	Maximum upper reservoir elevation	msl	7,360
14	Minimum upper reservoir elevation	msl	7,295
15	Maximum power reservoir elevation	msl	6,359
16	Minimum lower reservoir elevation	msl	6,297

17	Upper reservoir usable storage volume	Acre-ft	6,300
18	Lower reservoir usable storage volume	Acre-ft	1,016,717

19	Dam		
A	Existing upper or lower pool?		Existing lower
B	Upper reservoir empoundment		
	Dam type	Non-dim	CFRD or Earthen ring dam
	Dam length	ft	8,720
	Dam height	ft	45
C	Lower reservoir empoundment		Seminoe Dam (existing) (note: one alternative involves pumping from Seminoe (higher) and generating into Kortes Reservoir (lower)
	Dam type	Non-dim	Concrete arch
	Dam length	ft	530
	Dam height	ft	295

20	Water conveyance description						
A	Intake type (horizontal/vertical)						
B	Head race tunnel	Number	1	Length	6,600	Diameter	20.4
C	Penstocks	Number		Length	TBD	Diameter	
D	Draft tubes	Number		Length	TBD	Diameter	
E	Tailrace tunnel	Number	1	Length	200	Diameter	24.5
F	Has a hydraulic transient study been completed?	Yes ☐ No ☐N	Document attached? Yes ☐ No ☐				
G	Is surge protection required?	Yes ☐ No ☐ Not likely					

21	Powerhouse		
A	Powerhouse description	Underground (tentative)	
B	Powerhouse dimensions	ft	Tentatively, 70 x 280 x 120 high
C	Above ground?	Yes ☐ No ☐N, but positioning may be possible	
D	Separate transformer cavern	Yes ☐ No ☐	

22	Prime mover description		
A	Number of units	Non-dim	3
B	Unit type	Reversible pump-turbine generator-motor ☐Y	
		Conventional pump ☐	
		Conventional Pelton ☐	
		Conventional Francis ☐	
		Other (ex. hydraulic short circuit) ☐	
C	Variable speed units?	Yes ☐Y No ☐	
D	Unit operating range (pump)	MW	100-200
E	Unit operating range (generating)	MW	50-200
F	Rated flow (generate only)	cfs	5,555 (total all units)

G	Rated head (generate only)	cfs	
H	Rated head	ft	1,063
I	Unit centerline setting (with respect to minimum tailwater)	ft	
J	Runner/impellerdiameter	ft	
K	Unit cycle efficiency	%	82% (estimated)

23	Transmission		
A	Voltage of the existing transmission line	kV	
B	Voltage of the new transmission line	kV	230
C	Length of transmission from plant to interconnection point	ft	.5 mile to existing WAPA substation; 29 miles to Aeolus (Pacificorp)
D	Owner if existing transmission line		

C. PROJECT ENGINEERING STATUS

1	What are your strategies to advance the project under the preliminary permit timeline?	Confidential		
2	What is the level of project engineering definition? (see Attachment A, AACE Cost Estimate Classifications)	5 to 4		
3	Level of cost estimates performed to date (see Attachment A, AACE Cost Estimate Classifications)	5 to 4		
4	Engineering studies completed to date, provide copies of studies	Concept☐		
		Pre-feasibility☐		
		Feasibility ☐		
		Detailed ☐	% complete	
		Document attached? Yes ☐ No ☐		
5	What level of geotechnical exploration has been conducted at site?	None		
6	What level of transmission/interconnection studies have been conducted to date?	None		
7	What level of unit configuration and optimization studies have been completed to date?	None		
8	Project boundary description and acquisition status (including transmission corridor)	Boundary – see prelim permit; acquisition not yet initiated beyond consultation with BLM and Bureau of Reclamation		
		Document attached? Yes ☐ No ☐		
9	Type of land in project boundary	National forest☐		
		National landscape conservation system☐		
		Recreation management area☐		

		Research natural area☐
		Wild and scenic river☐
		Wilderness area☐
		Critical habitat☐
10	Consultation status	Initial consultation with BLM and Bureau of Reclamation
		Document attached? Yes ☐ No ☐

D. PROJECT REGULATORY STATUS

1	Preliminary permit issued?	Yes ☐Y No ☐ If yes, when and what is Project number? P-14087
2	If yes, what licensing process was selected?	ILP ☐ TLP ☐ ALP ☐
3	If yes, what regulatory steps have been taken to-date? (e.x., PAD filed, joint meeting held)	
4	If no, has preliminary permit application been filed?	Yes ☐ No ☐
5	If yes, when?	
6	Source of water (initial fill and makeup) (including any water rights issues)	Seminoe Reservoir, with water to be purchased from existing rights holders
7	Have affected resources been identified?	No issues identified to date
	Aquatic resources – fish, marcoinvertebrates, mussels, habitat	
	Botanical resources, including wetlands	
	Historical/cultural resources (including tribal resources)	
	Wildlife, including avian species, and reptiles and amphibians	
	Rare, threatened, and endangered species	
	Water quality	
	Recreation	
	Aesthetics	
7	Have study plans been developed?	Yes ☐ No ☐N If yes, please list.
9	Have agencies and other stakeholders had opportunity to review study plans?	Yes ☐ No ☐ If yes, what, if any, areas of disagreement have emerged?
10	Consultation with resource agencies and stakeholders to date (please list groups)	BLM and Bureau of Reclamation
11	Any environmental, regulatory, and technical studies or research completed? (please list)	
		Document attached? Yes ☐ No ☐

E. PROJECT COST AND REVENUE ESTIMATES

1	Cost		
A	Direct Capital cost	$	630,075,556
B	Engineering	$	30,000,000
C	Construction management	$	Included in Direct
D	Licensing	$	15,000,000
E	Contingency	$	126,015,111
F	Financing	$	24,992,720
G	Total project cost estimate	$	883,083,387
H	Annual O&M cost ($/MWH)	$/MWh	
I	Draw schedule (total cost by year or spend plan)		
J	Material takeoffs and cost estimate	Document attached? Yes ☐ No ☐N	
2	Revenue		
A	Have you conducted a power market study?	Yes	
B	Have you conducted a renewable integration study	Yes – with WY wind data	
C	Expected annual revenue	$	
D	Have you conducted benefit cost analysis?		

F. PROJECT SCHEDULE

1	Project development and construction schedules	Provide an overall project development and construction schedule indicating timelines for development, permitting, engineering, procurement, and construction.
		Document attached? Yes ☐ No ☐
2	Projected commercial operation date per unit	2020

G. DEVELOPER INFORMATION

1	Financial statements	Provide annual reports. If not a public entity, provide audited financial statements for the past three years including balance sheet, income statement, cash flow statement, and accompanying related notes. A separate submittal must be completed for each member of a partnership.	
		Document attached? Yes ☐ No ☐N	
2	Company net worth	Provide Tangible Net Worth as of the last audited fiscal year end. Tangible net worth shall be defined as the total assets less the sum of intangible assets, goodwill and total liabilities.	
		Document attached? Yes ☐ No ☐N	
3	Bankruptcy status	Has the company or your predecessor company declared bankruptcy in the past 5 years? If answer is yes, describe the situation and how it affects the company's ability to meet its credit obligations.	
		Yes ☐ No ☐N	Document attached? Yes ☐ No ☐

4	Company solvency	Are there any pending bankruptcies or other similar state or federal proceedings, outstanding judgments, or pending claims or lawsuits that could affect the solvency of the company? If answer is yes, describe the situation and how it affects the company's ability to meet its credit obligations.		
		Yes ☐ No ☐N	Document attached? Yes ☐ No ☐	
5	Power industry resume and assets	Identify any and all interests in power generation facilities with an identification of technologies, unit sizes, and project name.		
	Project Name	Ownership Percentage		Project Size (MW)

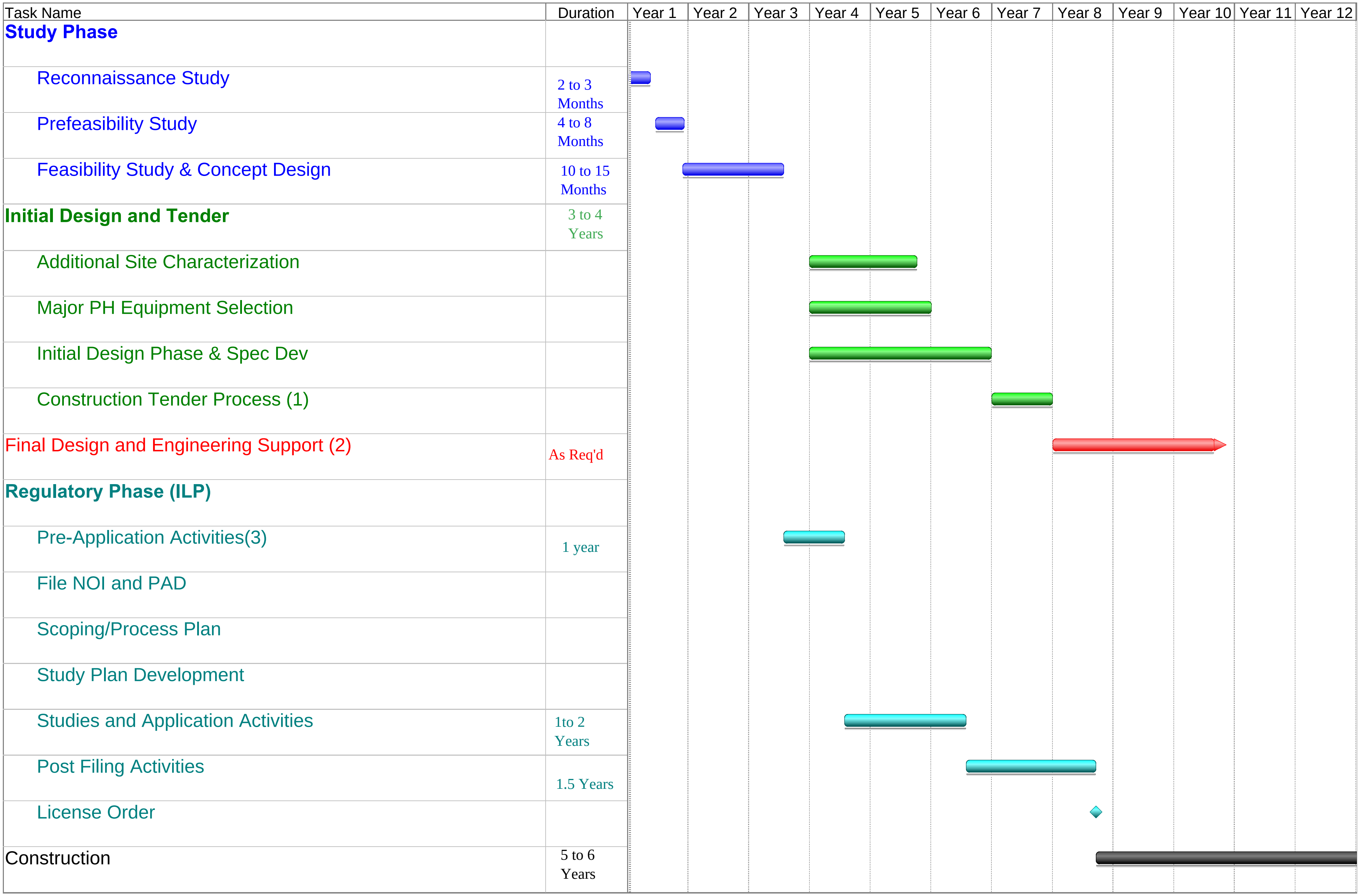
H. PROJECT FINANCING AND OWNERSHIP DESCRIPTION

1	Project financing approach		
2	Project ownership structure		
3	Existing power purchase and offtaker agreements		
4	Debt/equity split (if applicable)	(% / %)	
5	Other subsidies/incentives		
	Type		
	Value	$	
	Status		
	Type		
	Value	$	
	Status		
	Type		
	Value	$	
	Status		
6	Contracting methodology		

Attachments:

A. AACE Class 1 through 5 Cost Estimate Classifications

Pumped Storage Development Schedule



Notes:

(1) Assumes construction bid documents are released in advance of final design.

(2) Assumes engineering continues through tendering process as well as construction

(3) Pre-Application activities could be advanced depending on the owner's appetite for risk prior to completion of feasibility study

Table B-1. AACE Class 1 through 5 Cost Estimate Classifications

Estimate Class	Class 5	Class 4	Class 3	Class 2	Class 1
LEVEL OF PROJECT DEFINITION Expressed as a % of complete definition	0% to 2%	1% to 15%	10% to 40%	30% to 70%	50% to 100%
END USAGE Typical purpose of estimate	Concept Screening	Study or Feasibility	Budget Authorization or Control	Control or Bid/Tender	Check Estimate or Bid/Tender
METHODOLOGY Typical estimating method	Capacity Factored, Parametric Models, Judgment, or Analogy	Equipment Factored or Parametric Models	Semi-Detailed Unit Costs with Assembly Level Line Items	Detailed Unit Cost with Forced Detailed Take-Off	Detailed Unit Cost with Detailed Take-Off
EXPECTED ACCURACY RANGE Typical variation in low and high ranges (a)	L: -20% to -50% H: +30% to +100%	L: -15% to -30% H: +20% to +50%	L: -10% to -20% H: +10% to +30%	L: -5% to -15% H: +5% to +20%	L: -3% to -10% H: +3% to +15%
PREPARATION EFFORT Typical degree of effort relative to least cost index of 1 (b)	1	2 to 4	3 to 10	4 to 20	5 to 100
REFINED CLASS DEFNITION	Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systemic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than 1 hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation.	Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists.	Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists.	Class 2 estimates are generally prepared to form a detailed control baseline against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the “bid” estimate to establish contract value. Typically, engineering is from 30% to 70% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc.	Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor’s bid estimate, or to evaluate/dispute claims. Typically, engineering is from 50% to 100% complete, and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans.
END USAGE DEFINED	Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc.	Class 4 estimates are prepared for a number of purposes, such as but not limited to detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.	Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase “control estimates” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate may be the last estimate required and could well form the only basis for cost/schedule control.	Class 2 estimates are typically prepared as the detailed control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program.	Class 1 estimates are typically prepared to form a current control estimate to be used as the final control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution.
ESTIMATING METHODS USED	Class 5 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques.	Class 4 estimates virtually always use stochastic estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques.	Class 3 estimates usually involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project.	Class 2 estimates always involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.	Class 1 estimates involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities.
EXPECTED ACCURACY RANGE	Typical accuracy ranges for Class 5 estimates are -20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.
EFFORT TO PREPARE (for US$20MM project)	As little as 1 hour or less to perhaps more than 200 hours, depending on the project and the estimating methodology used.	Typically, as little as 20 hours or less to perhaps more than 300 hours, depending on the project and the estimating methodology used.	Typically, as little as 150 hours or less to perhaps more than 1,500 hours, depending on the project and the estimating methodology used.	Typically, as little as 300 hours or less to perhaps more than 3,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.	Class 1 estimates require the most effort to create, and as such are generally developed for only selected areas of the project, or for bidding purposes. A complete Class 1 estimate may involve as little as 600 hours or less, to perhaps more than 6,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.
ANSI Standard Reference Z94.2-1969 name; Alternate Estimate Names, Terms, Expressions, Synonyms	Order of magnitude estimate, ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb.	Budget estimate, screening, top-down, feasibility, authorization, factored, pre-design, pre-study.	Budget estimate, budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, development, basic engineering phase estimate, target estimate.	Definitive estimate, detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate.	Definitive estimate, full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Notes: (a) The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
(b) If the range index value of “1” represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

Source: AACE International Recommended Practice No. 18R-197, February 2, 2005.

APPENDIX C – BATTERY STORAGE DATA

US Battery Projects Summary			
Name of Project:	Rating: MW	Rating: MWh	Status:
NaS (NGK Insulators Ltd.)			
Charleston Energy Storage Project	1.0	6.0	Operational
PG&E Vaca Battery Energy Storage Pilot Project	2.0	14.0	Operational
PG&E Yerba Buena Battery Energy Storage Pilot Project	4.0	28.0	Operational
Milton NaS Battery Energy Storage System	2.0	12.0	Operational
Churubusco NaS Battery Energy Storage System	2.0	12.0	Operational
Bluffton NaS Energy Storage System	2.0	12.0	Operational
Wind-to-Battery MinnWind Project	1.0	7.0	Operational
Long Island Bus BESS	1.0	7.0	Operational
Japan-US Collaborative Smart Grid Project	1.0	6.0	Operational
Presideo Energy Storage Project	4.0	24.0	Operational
PowerCell (Xtreme)			
Lanai Sustainability Research	1.1	0.3	Operational
Kaheawa Wind Power Project II	10.0	7.5	Operational
Kahuku Wind Farm	15.0	3.8	Operational
Kaheawa I Wind Project	1.5	0.4	Operational
Duke Energy Business Services Notrees Wind Storage Demonstration Project	36.0	24.0	Operational
Pillar Mountain Wind Project	3.0	0.8	Contracted
Kaua'i Island Utility Cooperative	1.5	0.4	Operational
CCET Technology Solutions for Wind Integration	1.0	1.0	Construction
UltraBattery (Ecoult)			
PNM Prosperity Energy Storage Project	0.5	2.8	Operational
East Penn Manufacturing Co. Grid-Scale Energy Storage Demonstration	3.0	2.2	Operational
Li-Ion (A123 Systems)			
Southern California Edison Tehachapi Wind Energy Storage Project	8.0	32.0	Operational
Detroit Edison Advanced Implementation of Energy Storage Technologies	1.0	2.0	Operational
Laurel Mountain	32.0	8.0	Operational
Johnson City	8.0	2.0	Operational
Monroe County Community College	0.5	0.3	Operational
University of Hawaii Smart Grid Regional and Energy Storage Demonstration Project	1.0	1.0	Operational
Auwahi Wind Farm	11.0	4.4	Operational
Zn-Br Flow (Premium Power)			
National Grid Distributed Energy Storage Systems Demonstration	0.5	3.0	Contracted
National Grid Distributed Energy Storage Systems Demonstration	0.5	3.0	Contracted
Vanadium Redox Flow (Prudent)			
Prudent Energy VRB-ESS® - Gills Onions, California	0.6	3.6	Operational

Features and Applications of NAS® Battery System

February, 2014

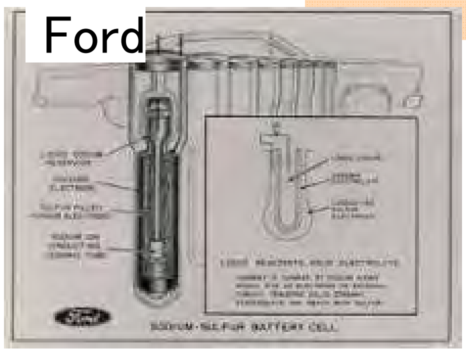
NGK INSULATORS, LTD.

History of NAS Battery Development

- NGK started R&D of NAS Battery from 1984 with TEPCO (Tokyo Electric Power Co.) and commercialized it on 2002.

1967 | 1980 | 1990 | 2000 | 2010

Ford found the principle



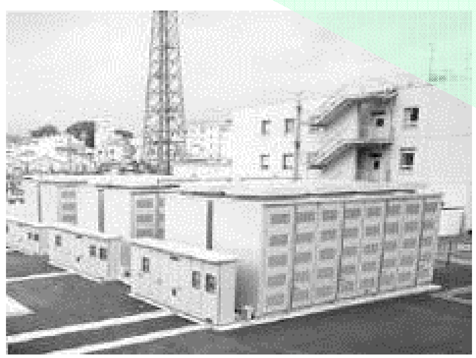
1971－1976
R&D in USA, Europe and Japan

1980－1990
Development for Utility Usage
Moon Light Project（NEDO）

1984 Start Joint R&D — TEPCO – NGK

Element R&D — Technical injection from BBC (now, ABB)

1989 Cell Development

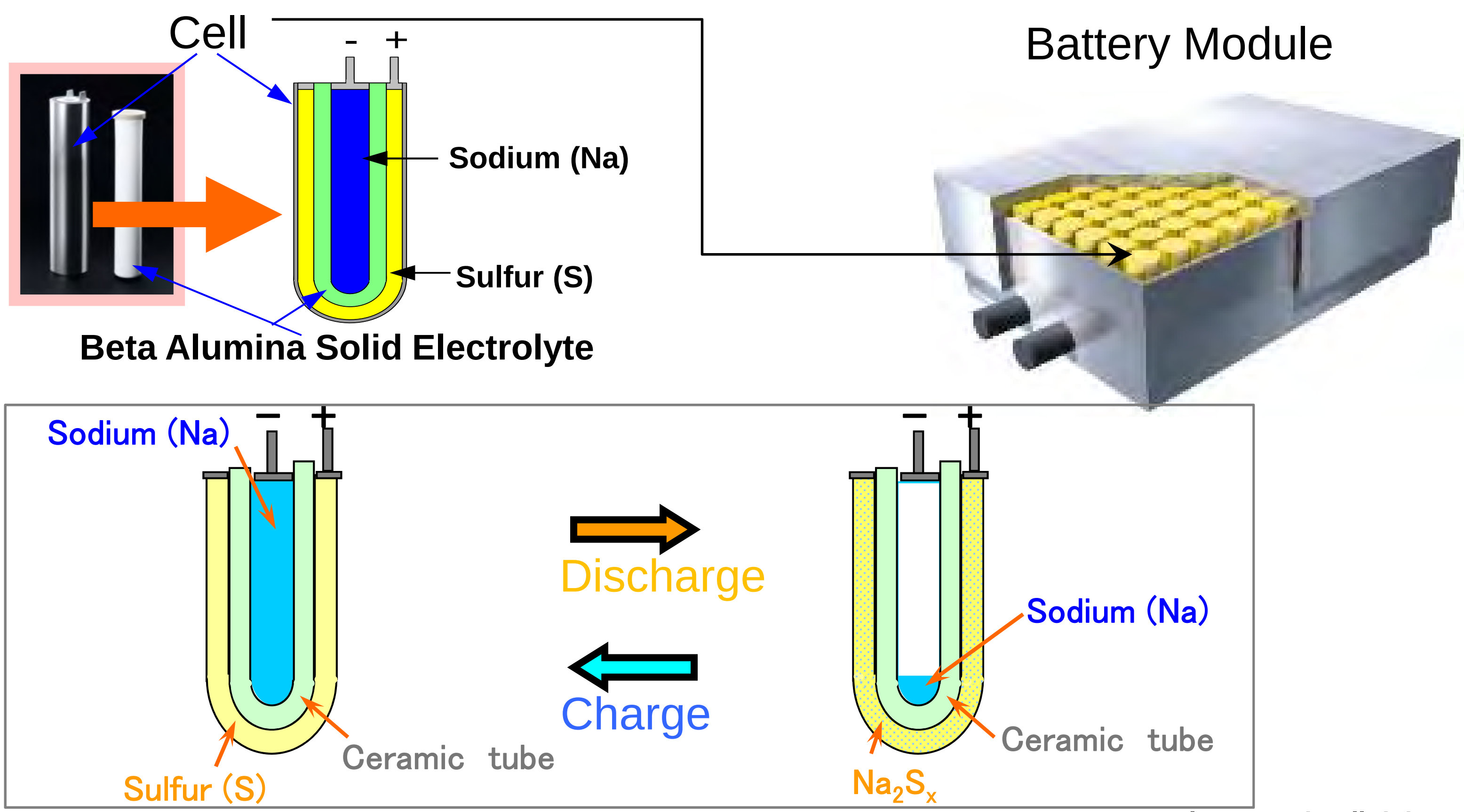


1997 Experiment /Evaluation

2002 Commercialization
World's Only Product

Structure of NAS Battery

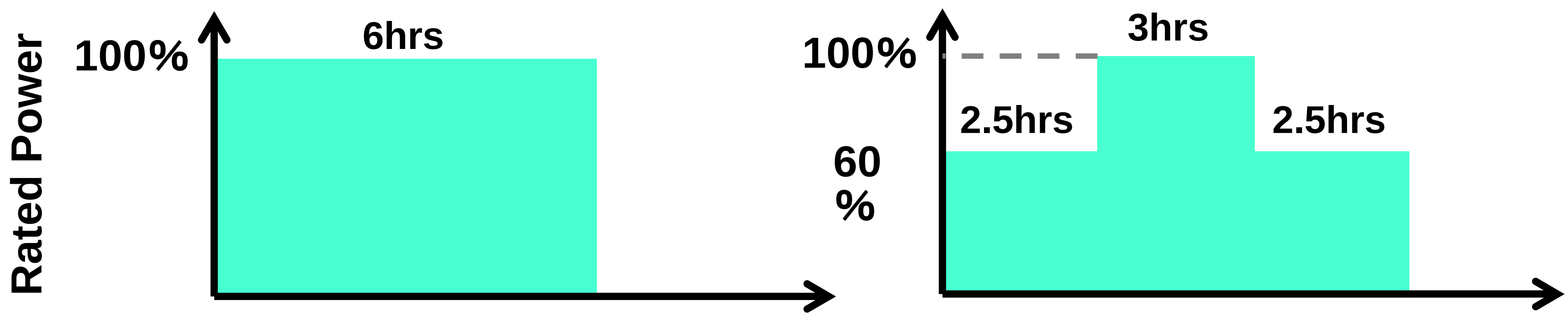
- Beta Alumina Ceramic Tube is key part of NAS Battery.
- NAS Battery is reliable and proven technology through extensive testing.
- Each module is thermally insulated and has an operating temperature range of 300 to 350 degrees C.
- Insensitive to ambient temperature (-20 to +40C).



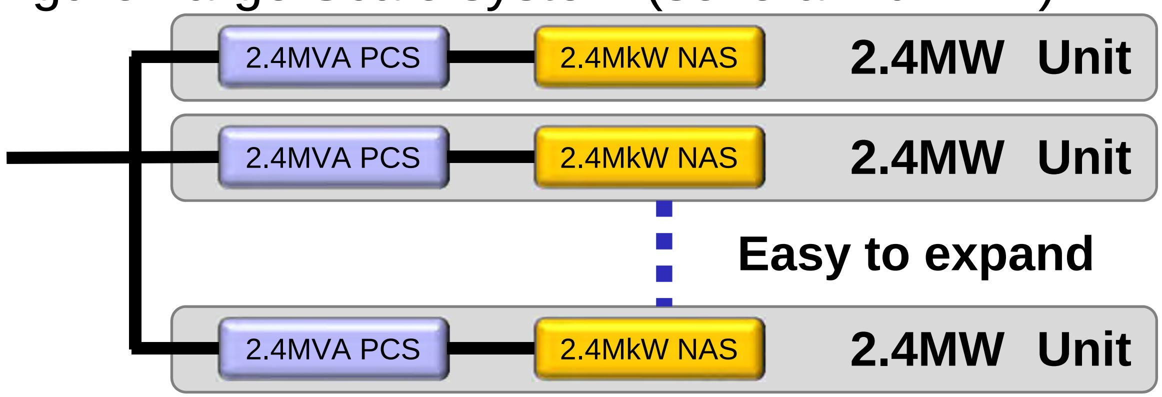
Technical Advantage of NAS Battery

NAS Battery System can ;

- ➢ discharge for Long Hours (6 hours or more). - LARGE CAPACITY



- ➢ configure Large Scale system (several 10 MW) - HIGH POWER

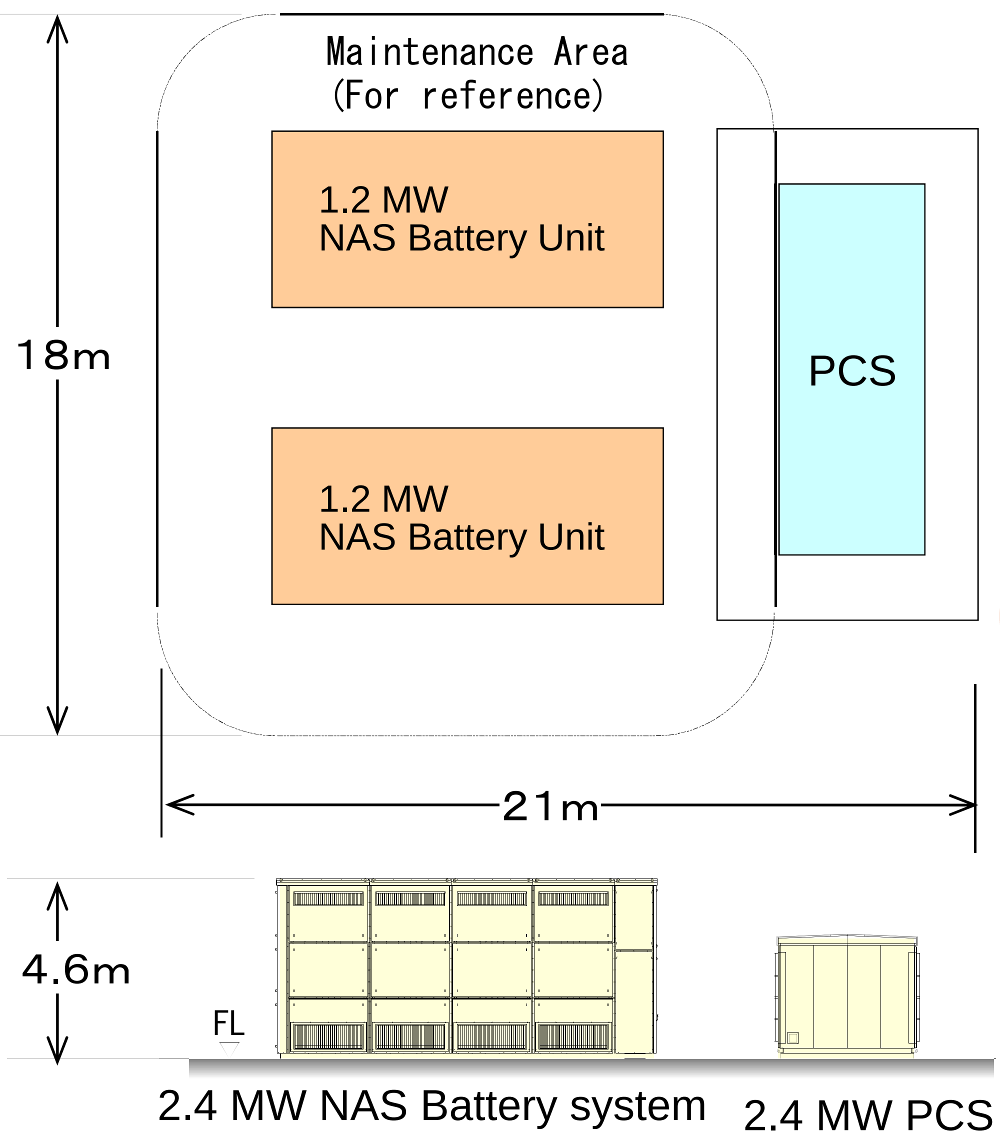


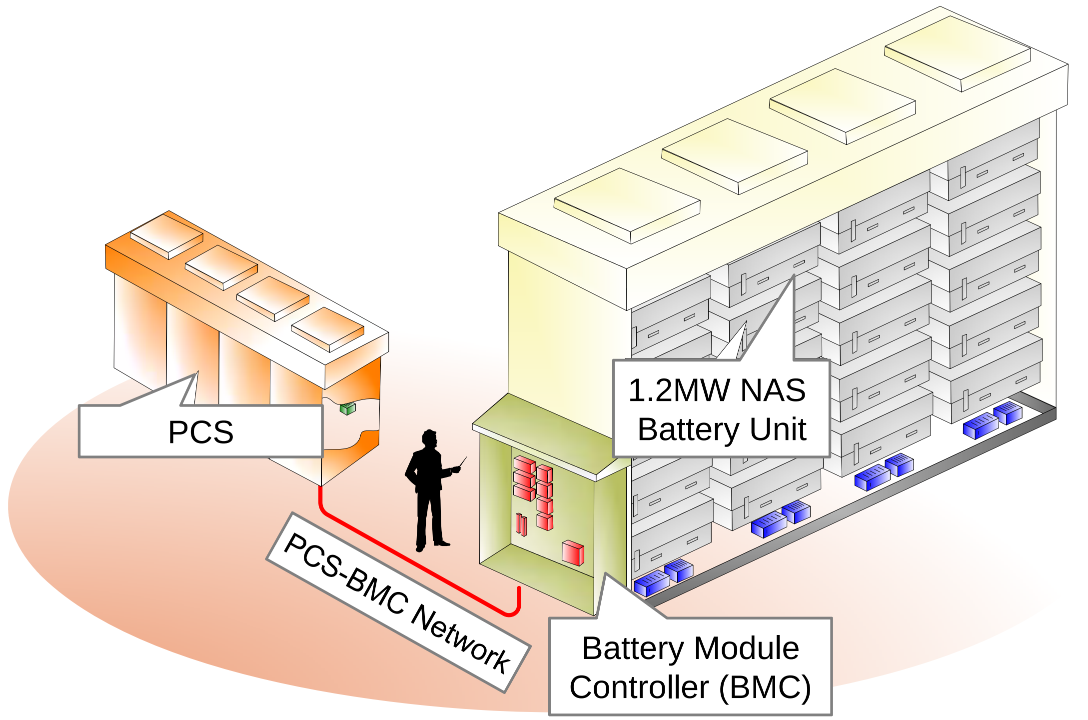
- ➢ realize high energy density due to special thin Ceramic Solid Electrolyte

  - LESS FOOTPRINT

- ➢ expect 4500 cycles (15 year- 300 cycles per year)

NAS Battery System – Layout (Less Footprint)





NAS Battery projects in North America

➢ More than 20 MW of NAS Batteries have been installed in North America .

BC Hydro
Load Leveling (Investment deferral)
Improving reliability (Islanding operation)

Xcel Energy
Wind Integration
Frequency Regulation

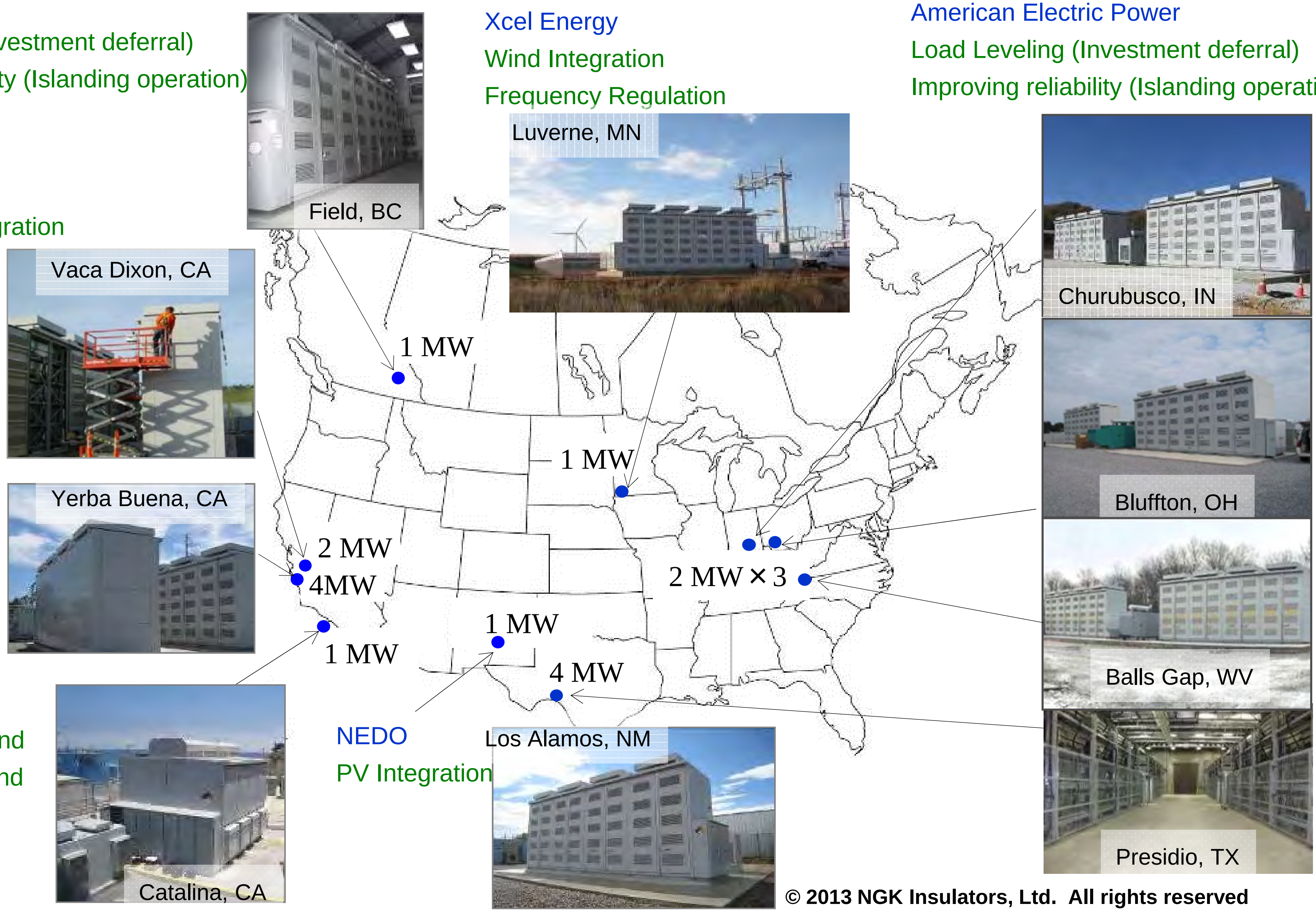
American Electric Power
Load Leveling (Investment deferral)
Improving reliability (Islanding operation)

PG&E
Load Shaping
Renewables Integration
Ancillary Services

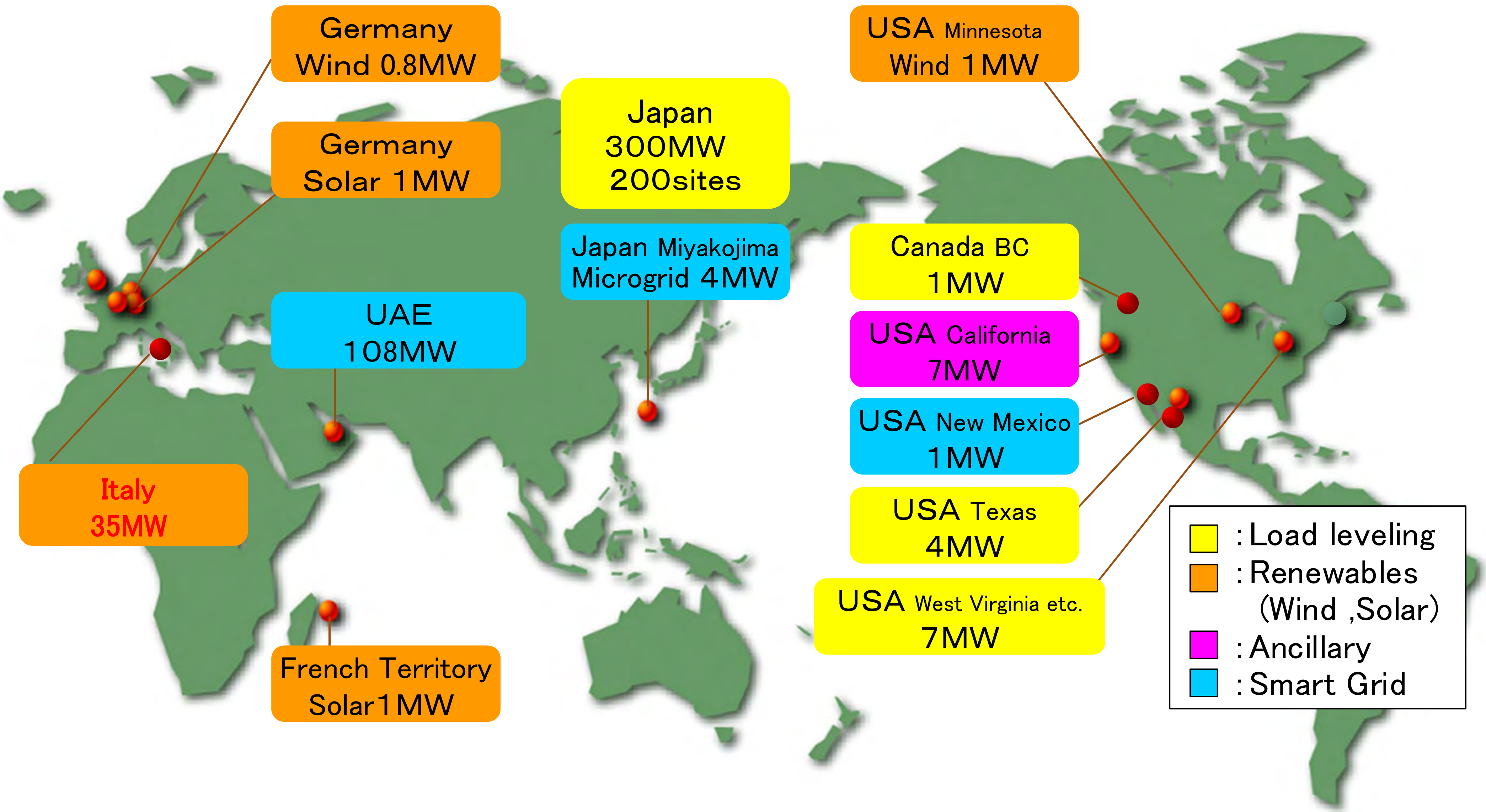
PG&E
Power Quality
Islanding
Load Shaping
Ancillary Services

SCE
Supply and demand adjustment in island

NEDO
PV Integration



NAS Battery Projects all over the world



Dynamic Power Resource™

Core Presentation

July 2011

Version 17

Xtreme Power, Inc.
Company Overview

Developer and manufacturer of Dynamic Power Resources™

- Founded in 2004 in Austin, Texas
- 20+ years of R&D in our technology
- Projects operating, contracted, and in final negotiations: >70 MVA, > 60 MWh
- US-based manufacturing
  - Oklahoma and Texas
  - 200 MWh of capacity
  - Expansion option: > 1 GWh
- Over $70 MM in funding: *SAIL* VP, Bessemer VP, Dow Chemical, Fluor, Dominion Power, BP, POSCO, Skylake Incuvest
- Utility industry leadership on our Board – Pat Wood, Foster Duncan

Xtreme Power

Experienced Leadership
Executive Team

Dr. Carlos Coe, Founder, President & Chief Executive Officer

- More than 30 years of experience in engineering and technology management in the commercial electronics and power generation and storage industries.

Dr. Alan Gotcher, Chief Technology Officer

- More than 25 years of leadership in the material science industry and a successful track record of introducing disruptive battery technologies positioned for rapid adoption.

Darrell Hayslip, Chief Development Officer

- More than 25 years of power industry experience, having held leadership roles in sales & marketing, system operations, policy, and development with EON, Calpine, Dynegy, and Westinghouse.

Ken Hashman, Chief Finance Officer

- 20+ years of experience in high-tech finance and operations management of rapidly growing companies.

Jeff Layton, Vice President, Operations

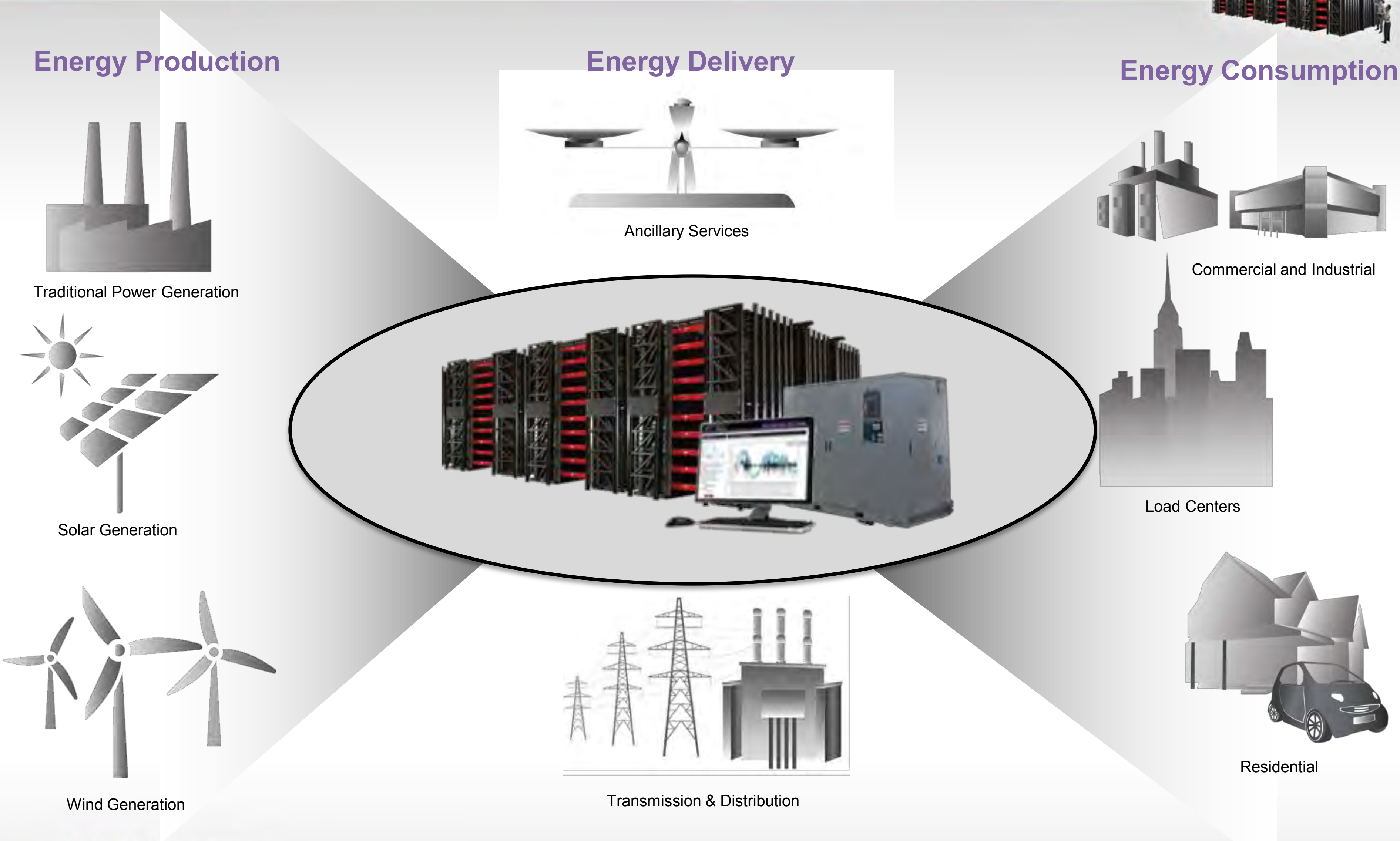
- 20 years of high technology operations and engineering experience.

Kin Gill, Vice President, General Counsel and Secretary

- Over 15 years experience with energy and technology companies, having executed securities, M&A and commercial transactions with an aggregate value in excess of $10 billion.

Xtreme Power

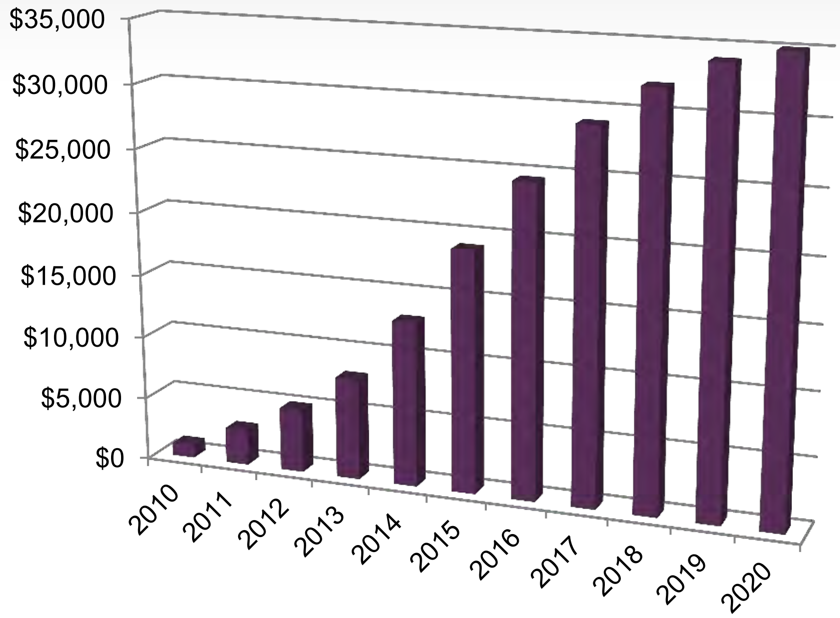
The 21st Century Grid



Xtreme Power

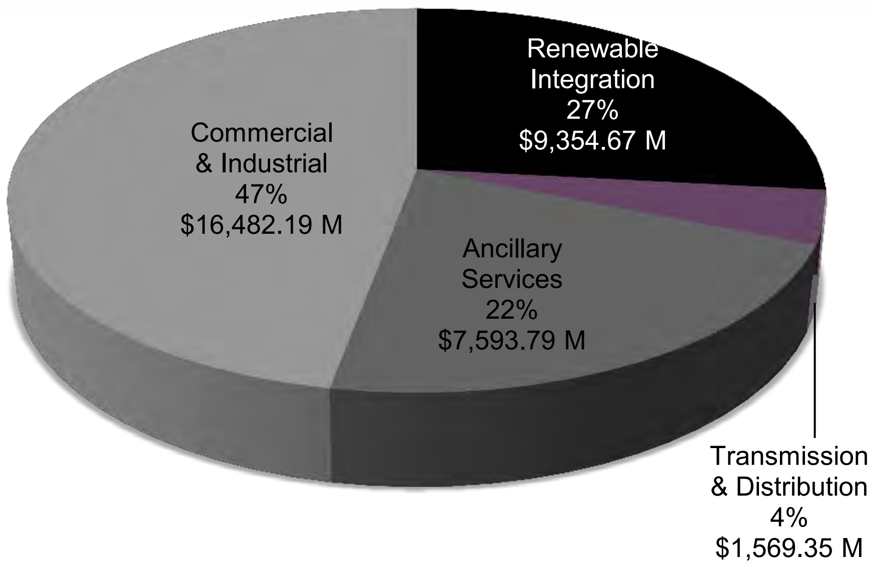
Energy Storage
A Rapidly Emerging Market

Market Size by Year



Source: Pike Research

Market Size by Segment



Source: Pike Research and Sandia National Laboratories

Target Segments

Renewable Integration

- Ramp Control
- Curtailment Mitigation
- Firming/Shaping
- Interconnection Compliance
- Grid Services

Transmission & Distribution Providers

- T&D Deferral
- Voltage Support
- Power Quality
- Grid Reliability Enhancement

Ancillary Service Providers

- Frequency Regulation
- Voltage Regulation
- Responsive Reserves

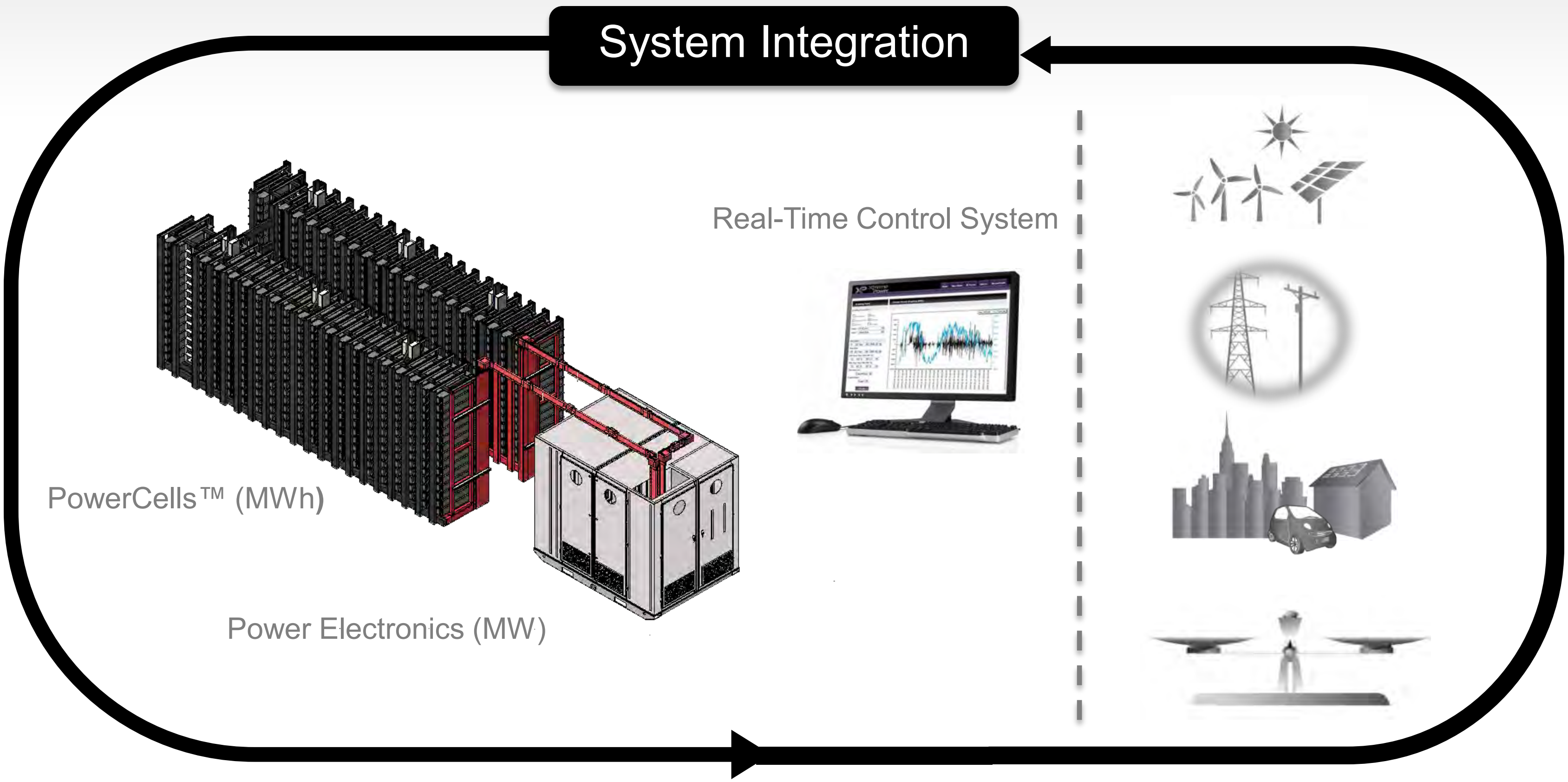
Commercial & Industrial

- Peak Shaving
- Load Leveling
- Power Quality

Xtreme Power

Xtreme Power Technology

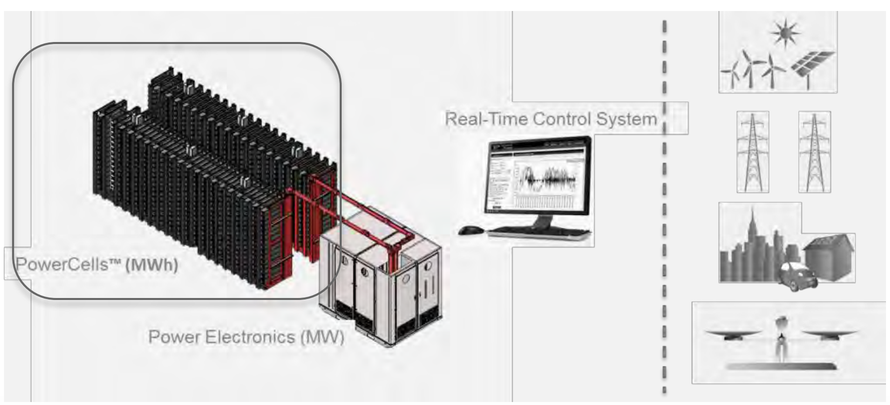
Dynamic Power Resource™

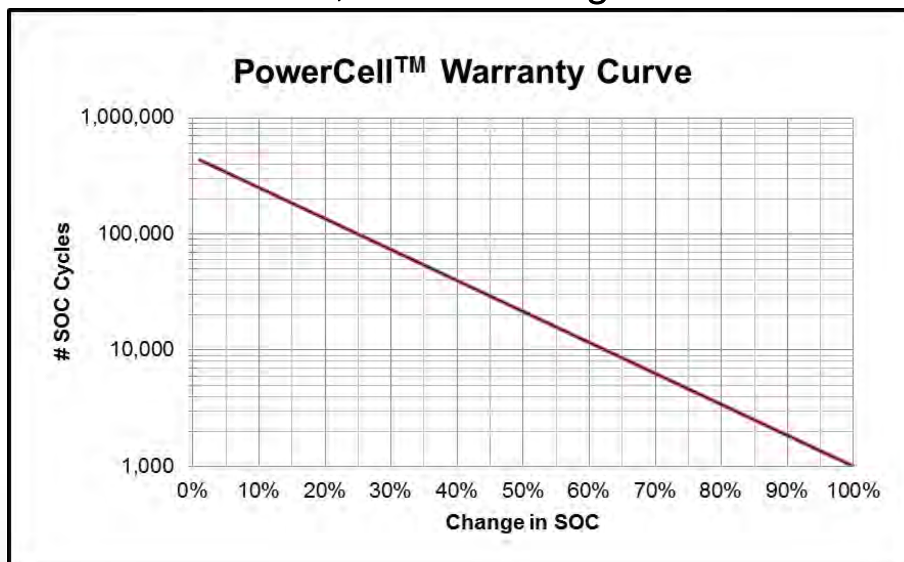


Xtreme Power

Xtreme Power Technology
PowerCells ™

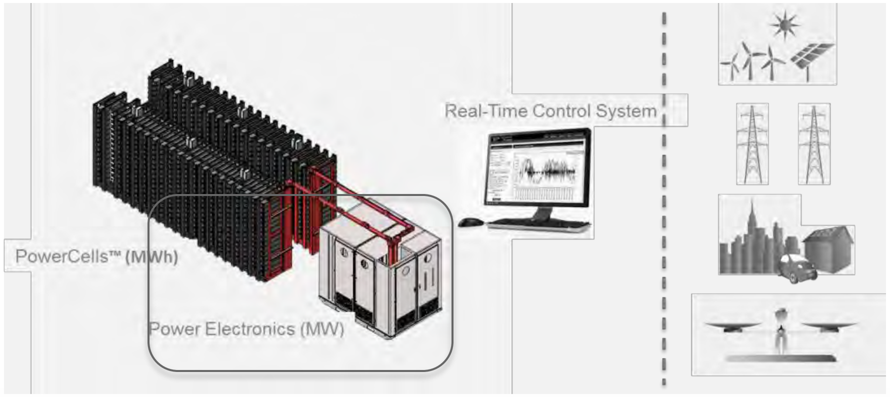
- Solid-state, dry cell battery
- Uniform performance characteristics for scalability
- Low internal resistance
  - Operates at ambient temperature
  - Highly efficient
  - High instant power capacity
- 98% recyclable
- Safe, ease of siting





Xtreme Power

Xtreme Power Technology
Power Electronics

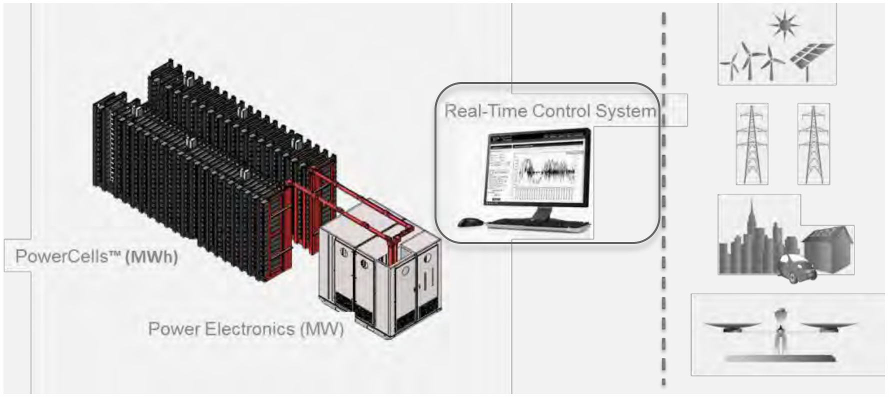


- Bi-directional inverter/charger technology
- Full four quadrant performance, managing real & reactive power requirements
- Solid State
  - Microsecond response
  - Nominal O&M
- Closed-Loop Water Cooled

Xtreme Power Technology

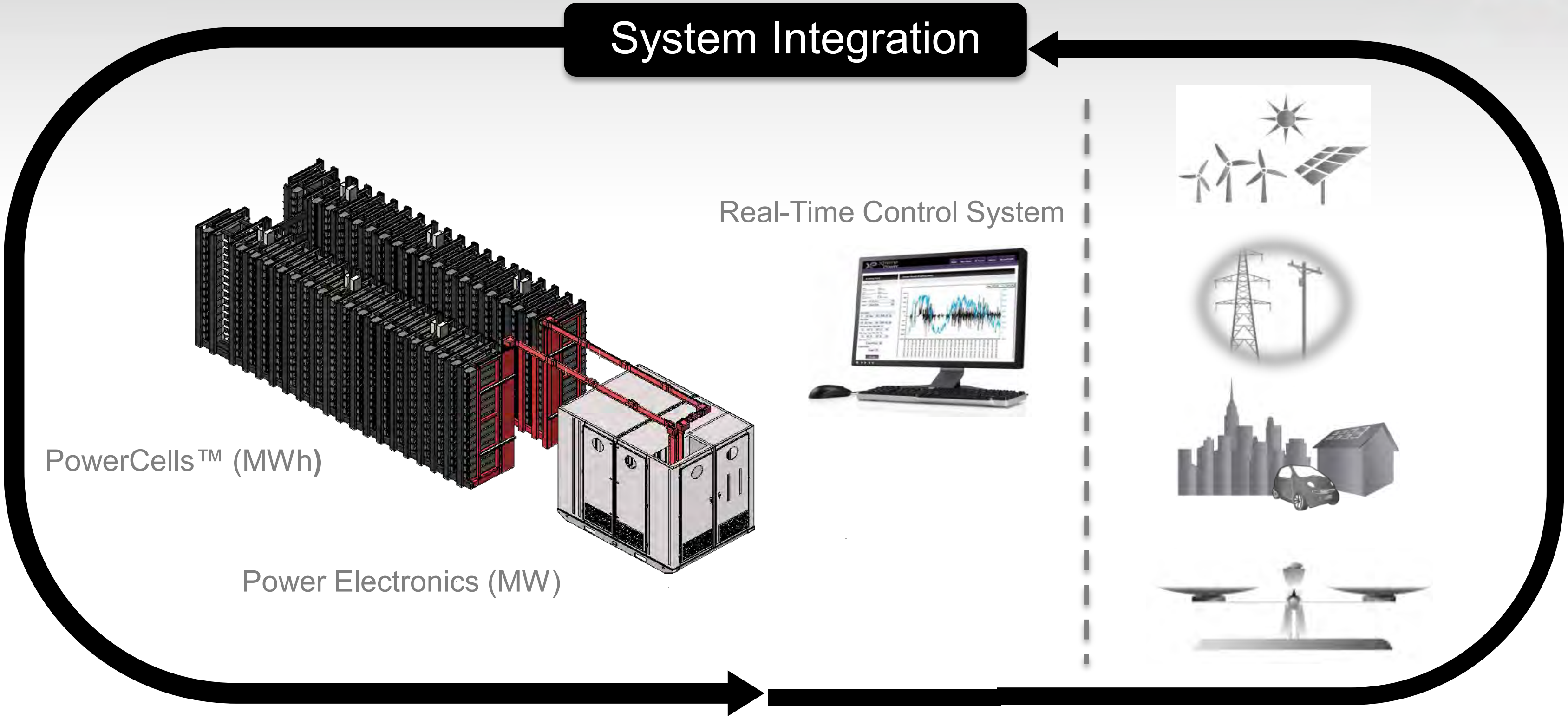
Real-Time Control System

- Custom algorithms for specific applications and services
- Fixed operating modes or dynamic response to changing market conditions
- Configurable program logic
- Redundant safety controls
- Local or remote control modes
- Automated or manual operation
- Meets or exceeds national Cyber Security standards



Xtreme Power

Xtreme Power Technology
System Integration



- Communication with existing/planned assets
- Balance of Plant experience, including turn-key services
- Modular approach allows scaling without compromising reliability

Xtreme Power

Economics to Consider

Total Cost of Ownership

Purchase

- Initial price
- Lead time
- System supplier

Install and Construct

- Shipping
- Permitting
- Site preparation
- Balance of Plant
- Installation
- Commissioning

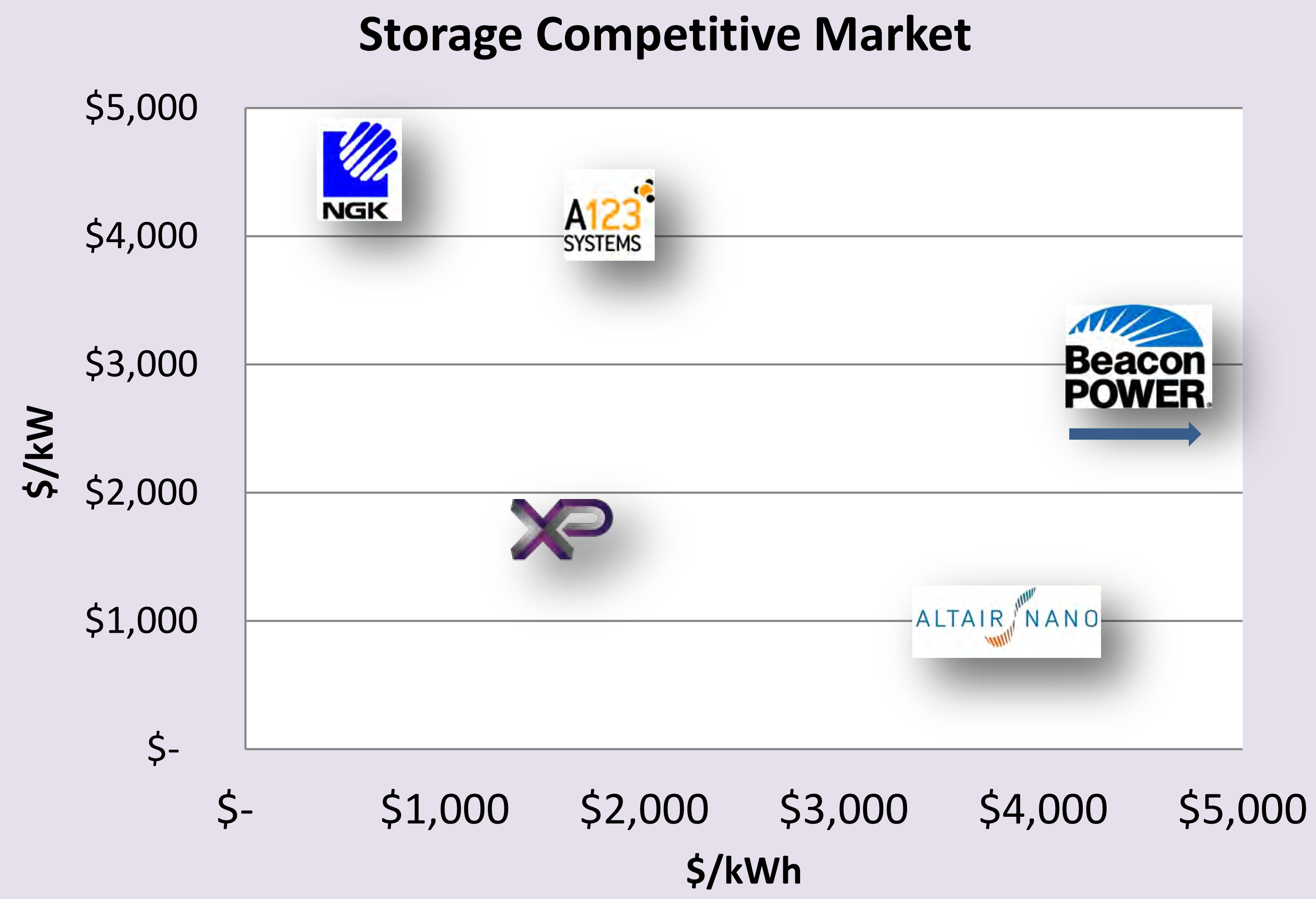
Operate

- Efficiency
- System Performance
- Reliability
- Ease of control modification

Maintain

- System life
- Recyclability
- Spare parts
- Technical services
- Warranty

System Price Comparison

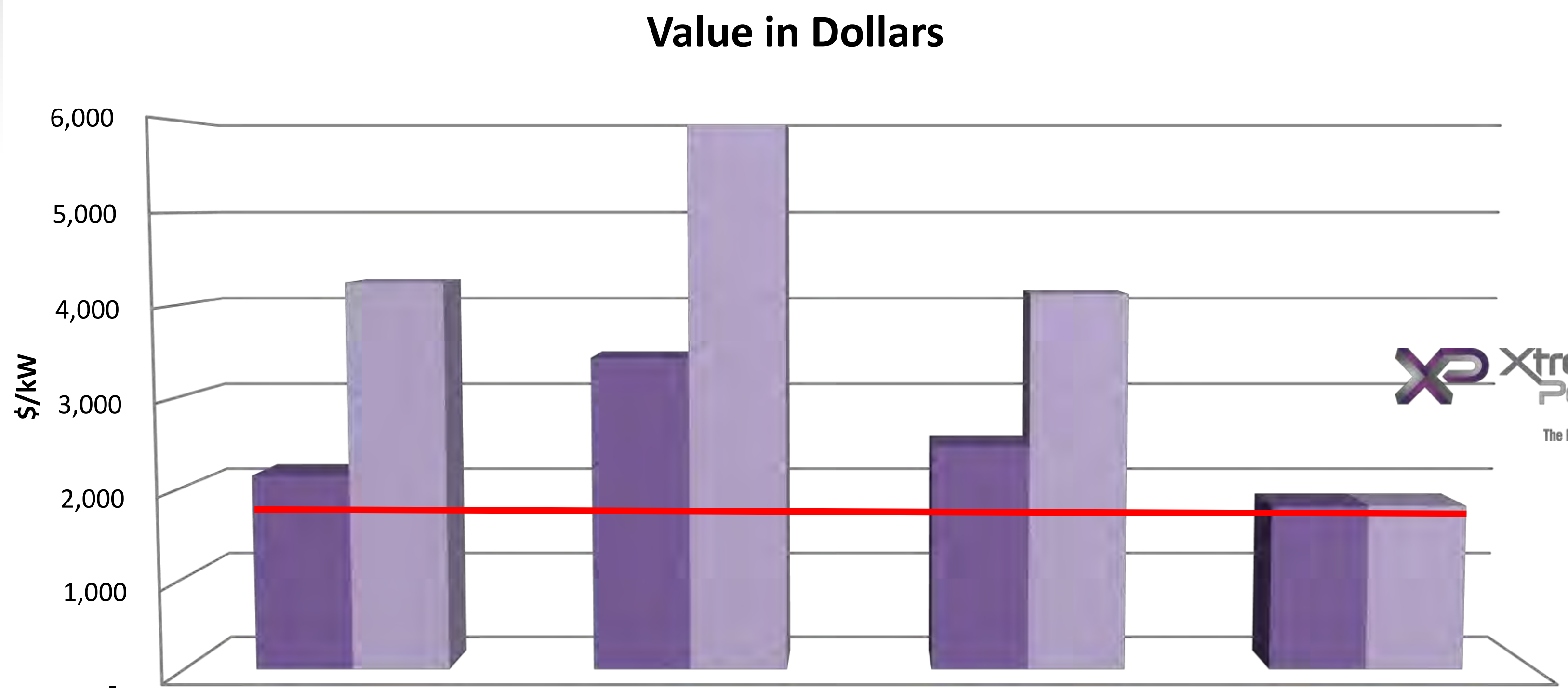


Source: EPRI Energy Storage Project A

Xtreme Power

Value Proposition of Storage

Application-specific Benefits



	Renewable Integration	Transmission & Distribution	Ancillary Service Providers	Commercial & Industrial
Low	2,143	3,430	2,468	1,808
High	4,249	5,948	4,125	1,808

Source: Sandia National Laboratories 2/2010

Typical DPR™ Economics

Equipment

- **1.5 MVA inverter/charger (480 VAC, 3 phase)**
- **1.0 MWh PowerCells**
- **Control System Hardware**
- **11' x 11' x 40 container**
- **Internal Ambient Controls as Needed**

Services/Labor

- System Integration
- Controls Programming
- Factory Acceptance Testing
- Field Installation and Commissioning

TOTAL
$1,600,000

DPR™ 15-100C

Real Projects, Real Solutions

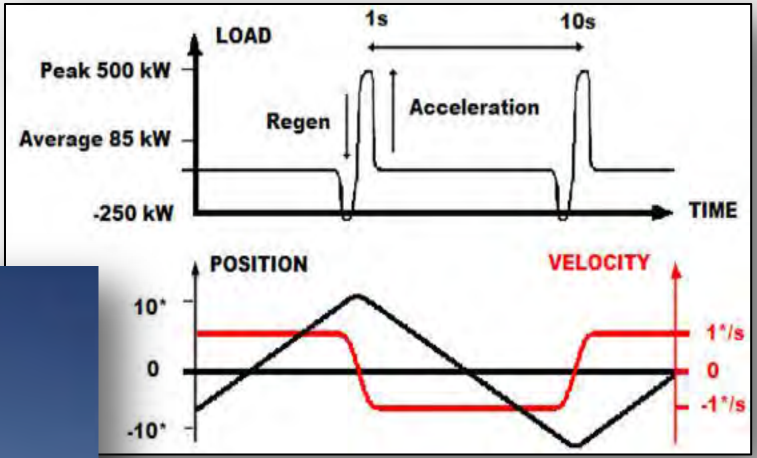
Project	Application	DPR™	COD	Services
South Pole Telescope	Microgrid	0.5 MW / 0.1 MWh	Q4 2006	Peak-Shaving, Load-leveling
Maui	Wind	1.5 MW / 1.0 MWh	Q3 2009	Ramp Control
Kahuku	Wind	15 MW / 10 MWh	Q1 2011	Ramp Control, Smoothing, Voltage Support
Xcel	Solar	1.5 MW / 1.0 MWh	Q3 2011	Ramp Control, Ancillary Services, Firming/Shaping
Lanai	Solar	1.125 MW / 0.5 MWh	Q3 2011	Ramp Control, Ancillary Services
Ford	End-User	0.75 MW / 2.0 MWh	Q3 2011	Peak-Shaving, Load-leveling
KIUC	Solar	1.5 MW / 1.0 MWh	Q3 2011	Responsive Reserves, Ramp Control, Ancillary Services
KWP II	Wind	10 MW / 20 MWh	Q4 2011	Ramp Control, Curtailment Capture, Responsive Reserves
Fosters*	Microgrid	3.0 MW/ 2.0 MWh	Q4 2011	Uninterruptible Power Supply
Duke Notrees	Wind	36 MW / 24 MWh	Q4 2012	Ramp Control, Ancillary Services
Tres Amigas	T&D	~ 100 MW / 200 MWh	Q2 2013	Ancillary Services, Wind Firming and Shaping

* Not announced publicly due to security restrictions.

Xtreme Power

South Pole Telescope
5 Years Experience

Location	South Pole, Antarctica
Application	Microgrid
DPR™	0.5 MW / 0.1 MWh
COD	Q4 2006
Services	Peak-shaving, Load-leveling



In collaboration with several centers of higher education, the University of Chicago chose the Xtreme Power DPR™ to power the 200-ton South Pole Telescope's scan cycles without infringing on the station's life support system. The Telescope requires up to 259,200 cycles/month.

Xtreme Power

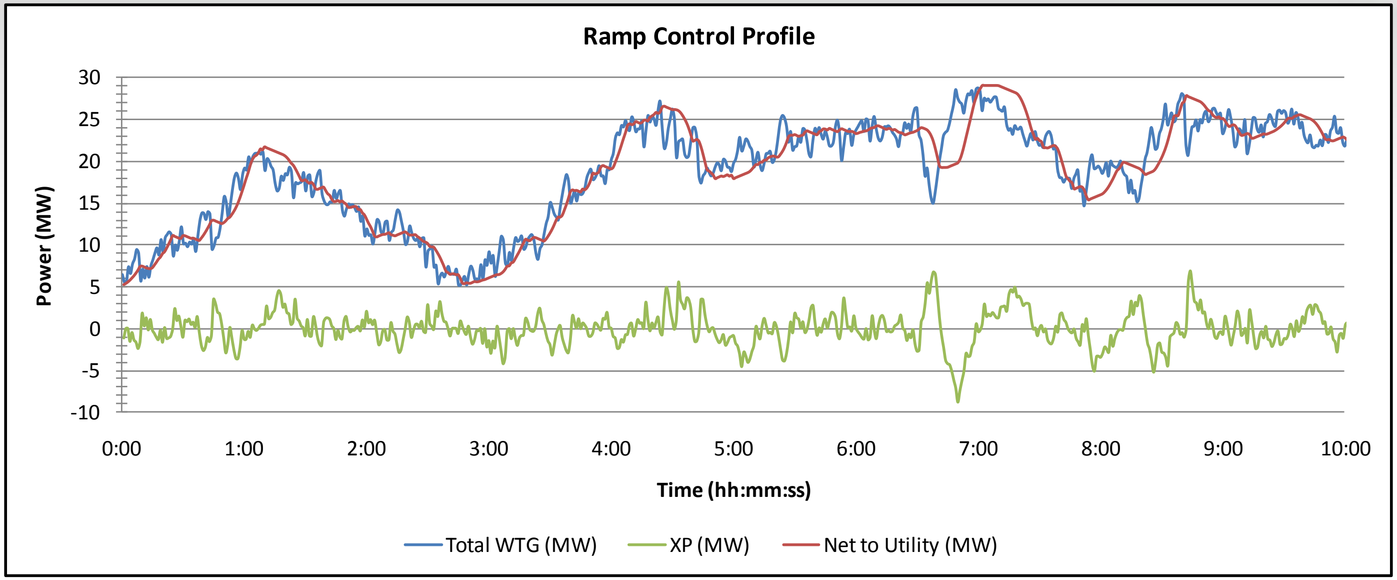
Kaheawa Wind Power
First Commercial Installation with Renewables

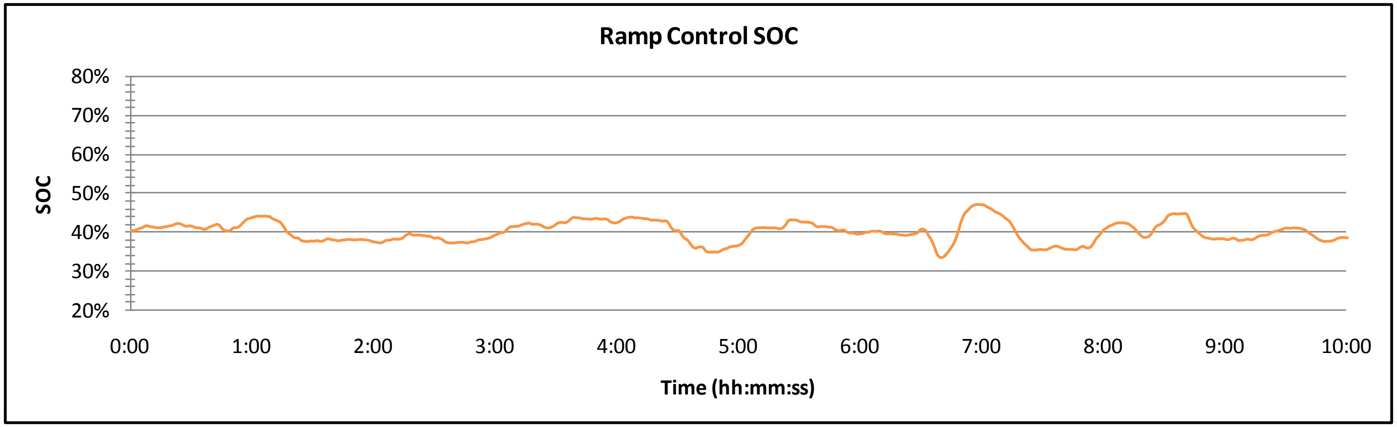
Location	Maui, Hi
Application	Wind
DPR™	1.5 MW / 1.0 MWh
COD	Q3 2009
Services	Ramp Control

The first utility-scale Xtreme Power DPR™ operates on a 30 MW wind farm on a 80-200 MW grid. This DPR™ smoothes output to ±100 kW/min and controls ramps to ±1 MW/min.

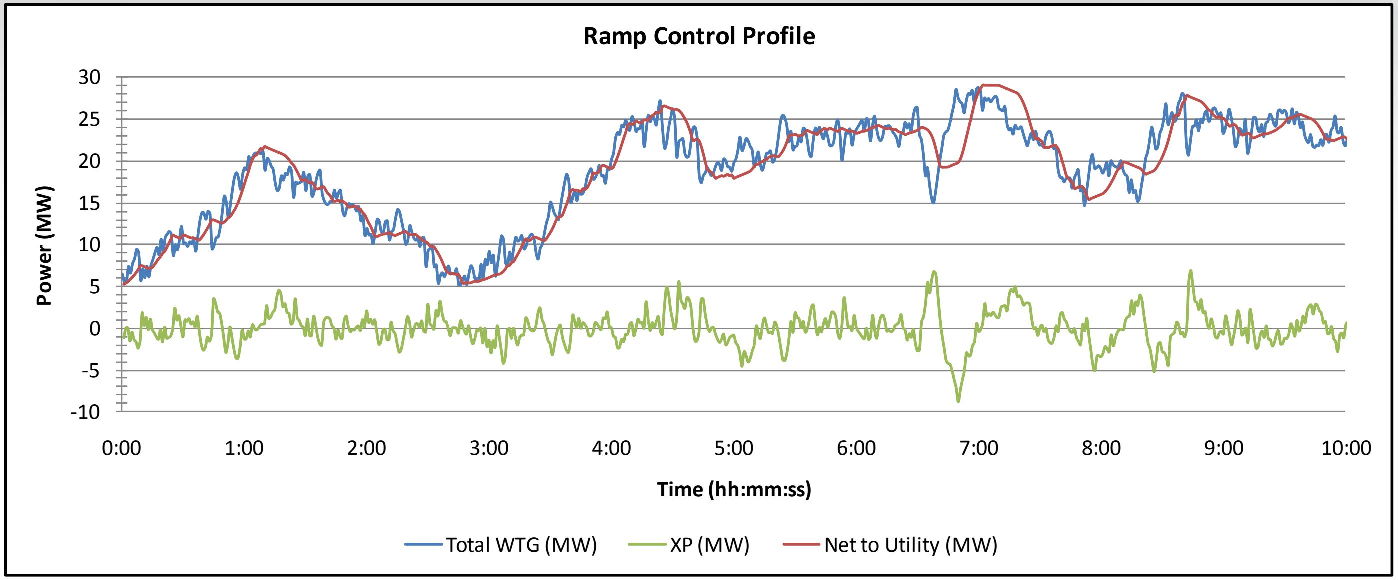
Xtreme Power

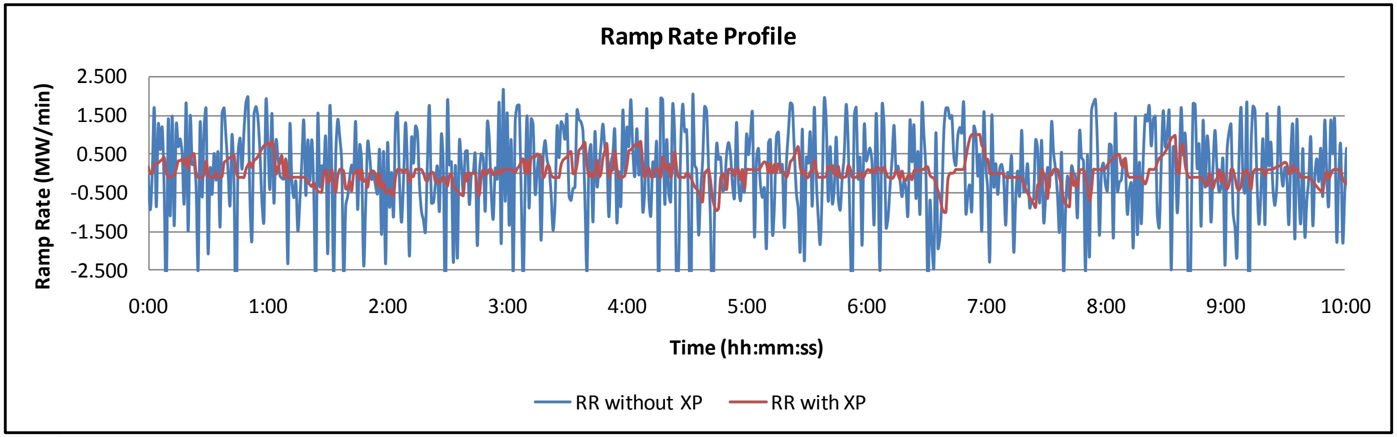
Proof of Performance





Proof of Performance





Xtreme Power

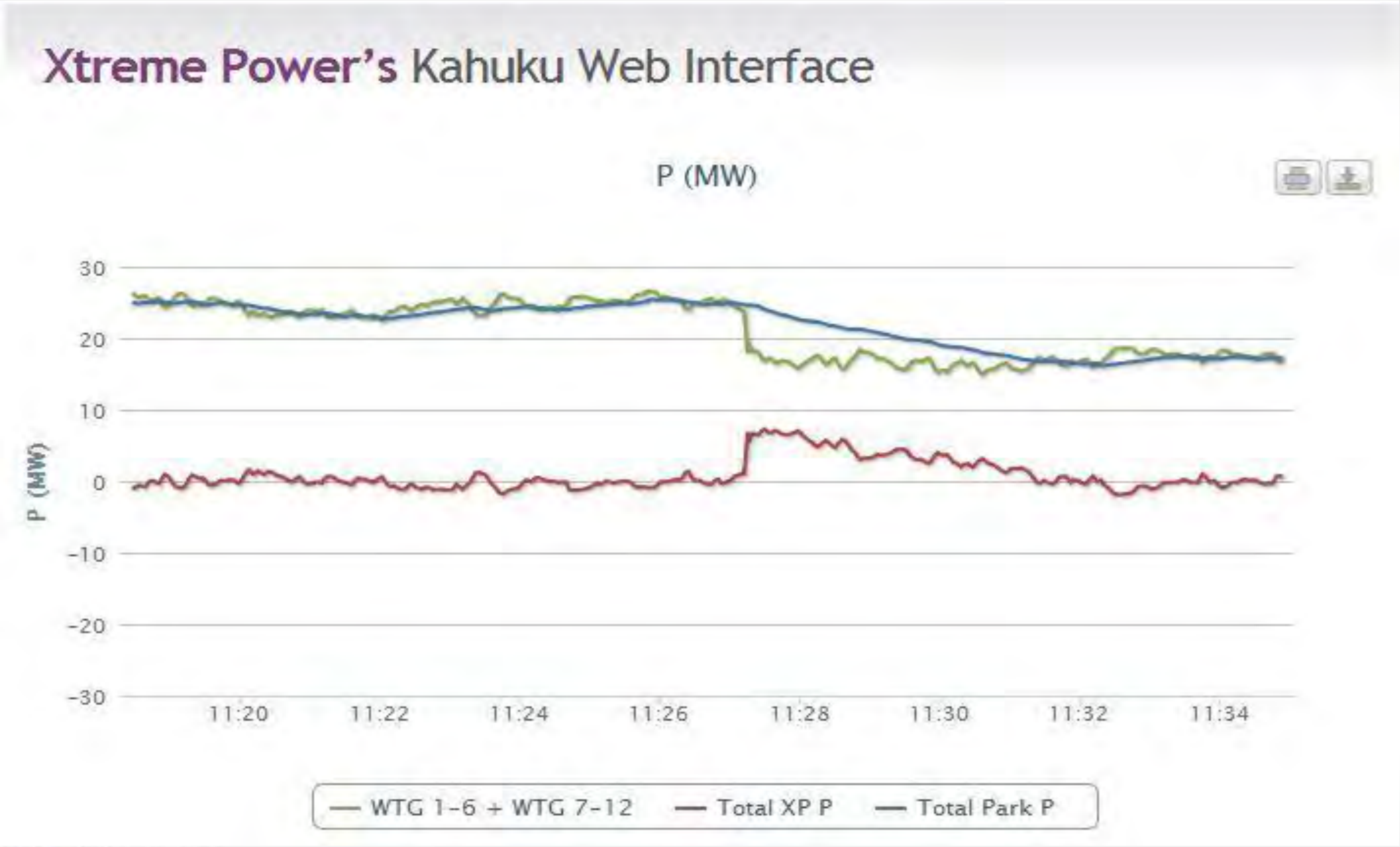
Kahuku Wind Power

Largest US Wind Application in Service

Location	Oahu, HI
Application	Wind
DPR™	15 MW / 10 MWh
COD	Q1 2011
Services	Ramp Control, Smoothing, Voltage Support

The DPR™ is integrated with the operation of First Wind's 30 MW Kahuku wind farm, enabling interconnection at the end of an existing 46 kV radial line and compliance with HECO's stringent PPA ramp control and smoothing requirements.

Kahuku Wind Power
Ramp Control & Smoothing



Xtreme Power

Kaheawa Wind Power II

Reducing Curtailment & Increasing Revenues

Location	Maui, HI
Application	Wind
DPR™	10 MW / 20 MWh
COD	Q4 2011
Services	Ramp Control, Curtailment Capture, Responsive Reserves, Voltage Support, Frequency Response

This DPR™ will operate on a new 21 MW wind farm on the island of Maui, enabling timely connection to the exiting grid. The DPR™ will also allow MECO to source responsive reserves and other critical services from KWPII, making it possible to reduce the operation of existing diesel generators and also reduce air emissions.

Xtreme Power

Xcel and SolarTAC
Mainland Installation for Testing with Solar

Location	Aurora, CO
Application	Solar
DPR™	1.0 MW / 1.0 MWh
COD	Q3 2011
Services	Ramp Control, Ancillary Services, Firming/Shaping

SolarTAC
Technology Acceleration Center

This system is collecting operational data on the integration of energy storage and solar energy systems at the Solar Technology Acceleration Center.

Xtreme Power

Lanai Sustainability Research
Doubling Renewable Output

Location	Lanai, HI
Application	Solar
DPR™	1.125 MW / 0.5 MWh
COD	Q3 2011
Services	Ramp Control, Ancillary Services

Lanai Sustainability Research's 1.2 MW solar farm is currently curtailed to 600 kW, until it can guarantee output that will not vary by more than ±360 kW/min. DPR™ will smooth power and increase its output to full capacity, as well as provide ancillary services.

Xtreme Power

Ford Michigan Assembly Plant

Reducing Costs, Increasing Reliability

Location	Wayne, MI
Application	End-User
DPR™	0.75 MW / 2.0 MWh
COD	Q3 2011
Services	Peak Shaving, Load-leveling

Ford selected the Xtreme Power DPR™ to operate with one of the largest solar power generation systems in Michigan. The DPR™ will help the plant save an estimated $160,000 in energy costs annually by shaving peak demands and leveling load.

Kaua’i Island Utility Cooperative
Taking Advantage of DPR™ Versatility

Location	Kaua’i, HI
Application	Solar
DPR™	1.5 MW / 1.0 MWh
COD	Q3 2011
Services	Responsive Reserves, Ramp Control, Ancillary Services

The KIUC DPR™ will mitigate the variability of a 3 MW solar PV project for the Kaua’i Island Utility Cooperative. This marks Xtreme Power’s first direct sale to a utility, and first project to provide responsive reserves.

Duke Notrees

World's Largest Battery Energy Storage System with Wind

Location	Odessa, TX
Application	Wind
DPR™	36 MW / 24 MWh
COD	Q4 2012
Services	Ramp Control, Ancillary Services

Duke Energy plans to match a $22 million grant from the U.S. Department of Energy to install a DPR™ capable of storing electricity produced by Duke's 153 MW Notrees wind farm. After due diligence, Duke Energy chose Xtreme Power to design, install and operate the largest battery storage system in the world integrated with a wind farm.

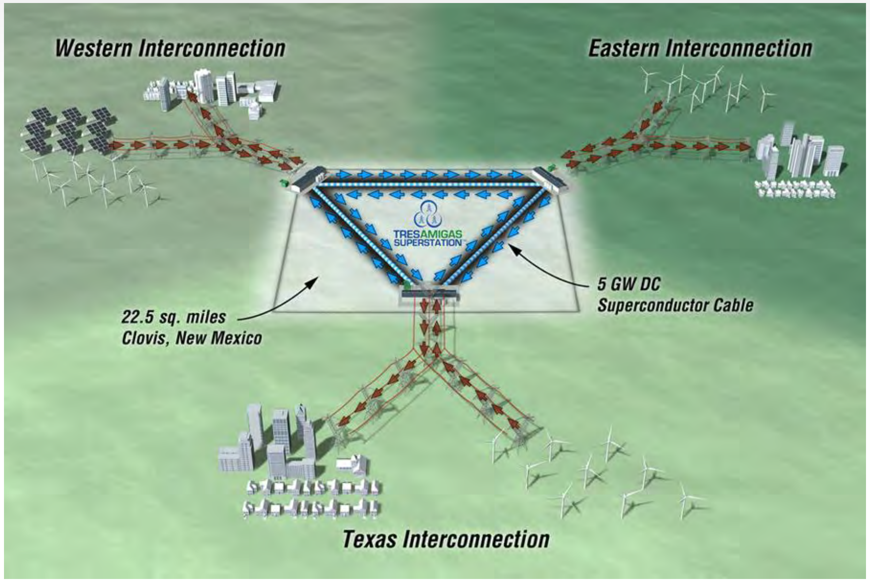
Xtreme Power

Tres Amigas

Providing America's First Common Interconnection

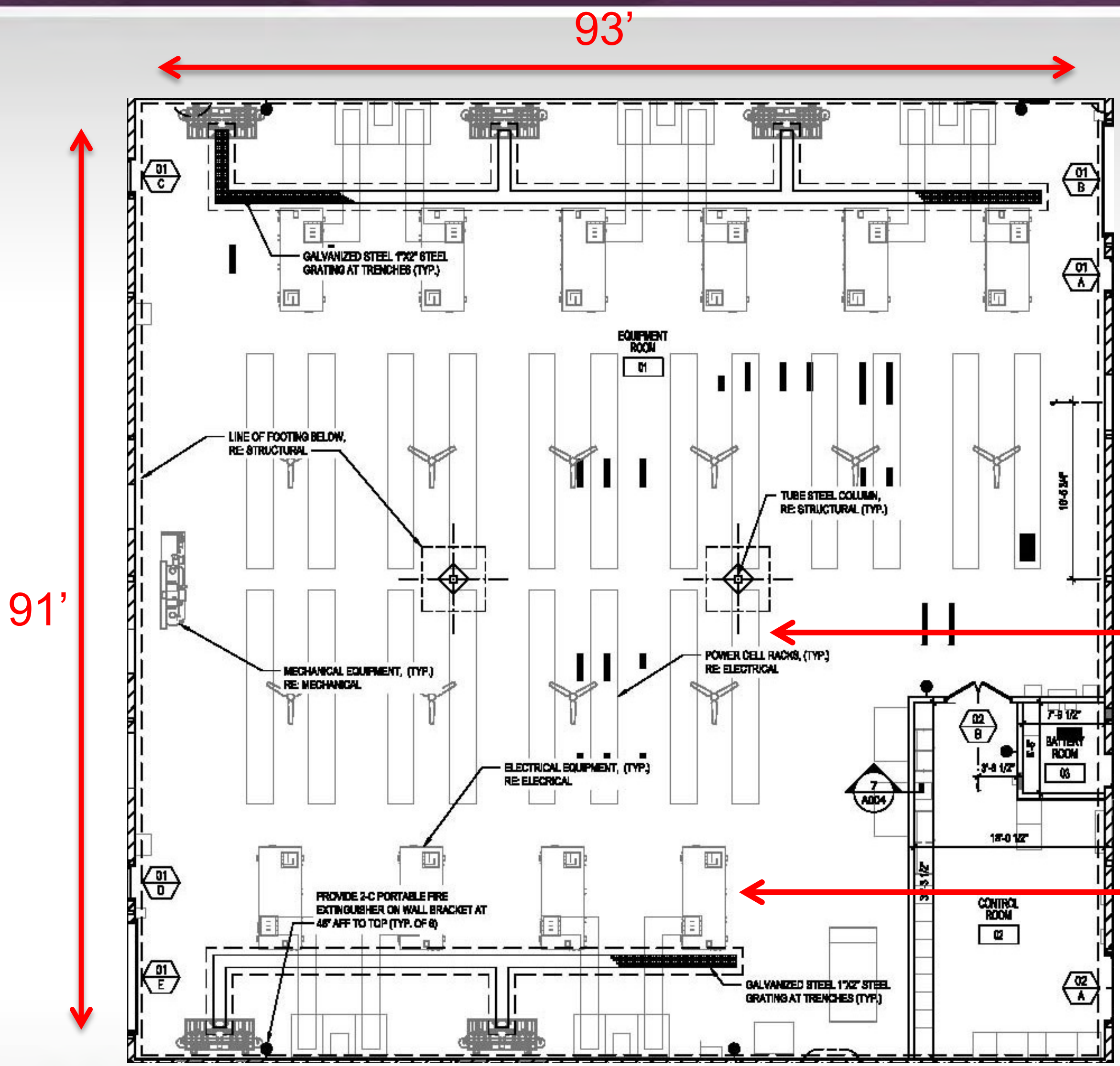
Location	Clovis, NM
Application	T & D
DPR™	~100 MW / ~200 MWh
COD	Q2 2013
Services	Ancillary Services, Wind Firming and Shaping

TRESAMIGAS LLC



By implementing an estimated 100 MW/ 200 MWh DPR™, the Tres Amigas SuperStation will deliver a reliable supply of renewable power amongst America's three power grids, the Eastern, Western (WECC), and Texas (ERCOT) Interconnections.

System Layout



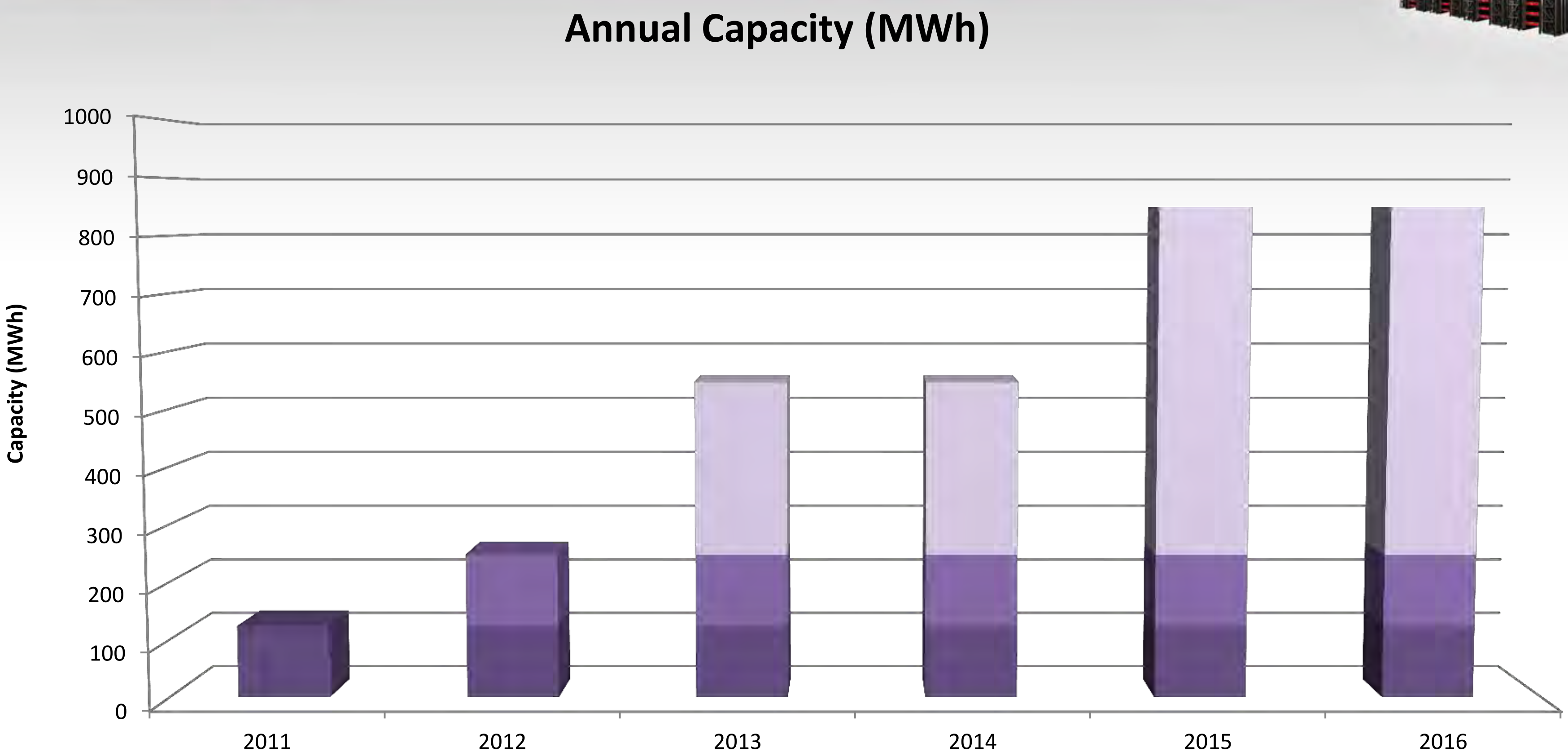
Layout of a

15 MW / 20 MWh DPR (423 sq-ft/MWh)

PowerCell™ Racks

Power Electronics

Production Capacity



	2011	2012	2013	2014	2015	2016
Phase 2 expansion			300	300	600	600
Phase 1 expansion		125	125	125	125	125
Current	125	125	125	125	125	125

The Power to Control.

DPR™ 15-100C

The Power to Control.

Xtreme Power offers a utility-scale Dynamic Power Resource™ (DPR™), ideal for a variety of applications. The DPR™ 15-100C is a standard, containerized unit comprised of 1.5 MVA bi-directional power electronics, 1 MWh of hyper-efficient energy storage technology, and a versatile, programmable control system, all integrated to operate with your specific generation, grid, or load application.

Proven Performance

Proven by rigorous field applications in commercial service, Xtreme Power's DPR™ is capable of so much more than just storing off-peak energy for use on-peak. The DPR™ efficiently provides quality, on-demand power.

- *Micro-second response and power precision within 10 kW*
- *Round-trip efficiency > 90% (AC-DC-AC and DC-AC-DC)*
- *One solution to simultaneously provide varying services*
- *Capable of supplying or absorbing real and reactive power*
- *Performs thousands to millions of cycles over a broad range of uses and depths of discharge*

Safe and Environmentally Friendly

The Xtreme Power PowerCell™ eliminates risks associated with other energy storage technologies, bringing peace of mind and a better bottom line.

- *Non-Hazmat Rated and no special site permitting required*
- *Operates at ambient temperatures*
- *95% of PowerCell™ materials recovered and recycled*

Competitive Cost

Not only does the DPR™ have a competitive initial cost, but the lowest total cost of ownership in the industry.

- *Complete engineered, integrated solution whose initial cost includes storage, power management and controls*
- *No pumps, no tanks, no extensive or expensive O&M*
- *Designed for 20 year life with easy PowerCell™ replacement*

Containerized Unit

Xtreme Power offers its DPR™ 15-100C in a convenient, shippable container. Pictured above, the ISO certified container has been specifically designed to incorporate additional benefits.

- *May be transported to a number of different sites*
- *Exterior roll-up doors allow for easy maintenance without requiring additional square footage*
- *Easy installation and quick set-up*
- *Automatically shuts down if an entrance is tampered with*
- *Easily retrofitted for operation in extreme climates*
- *Durable steel frame, welded in-house*

Specifications

Dynamic Power Resource™

Rated Power .... 1.5 MVA (Bi-directional)
Energy Storage .... 1 MWh
System Container Dimensions .... 40'L x 11'W x 11'H
Total System Weight .... < 100,000 lbs
Power Delivery
Max Instantaneous .... 200% of rated power, for 3 seconds
Max Continuous .... 150% of rated power, for 5 seconds
VAR Capability .... ± 1.5 MVAR
AC Voltage (Input/Output) .... 480 VAC 3-phase*
DC Bus Voltage .... 750 - 1,200 VDC
Output Normal Frequency .... 50 Hz or 60 Hz
Total Parasitic Load .... 10 kW per MW
Round Trip Efficiency .... > 90%
Cooling Requirements .... Ventilation only**
Relative Humidity .... 95% RH non-condensing
Ambient Temperature Range .... -20°F to 110°F without derating
Altitude Range .... Sea Level to 5,000' without derating
Seismic Load Level .... Any seismic zone
Other Environmental Restrictions .... No siting restrictions

*Can be stepped up to any required voltage
**Except for liquid cooled IGBT

Power Electronics

Dimensions .... 82"L x 96"W x 84"H
Weight .... < 9,000 lbs
Operational Input Voltage .... 750 - 1,200 VDC
Rated Input/Output Power .... 2,000 Amps DC
Rated Output Voltage .... 480 VAC 3-phase
Real Power Regulation .... ± 2% of rated power
Reactive Power Regulation .... ± 2% of rated power
Output Current & Voltage Distortion .... Total Harmonic Distortion << 5%
Rated Output Frequency .... 50 Hz or 60 Hz, ± 0.1%
Efficiency .... > 98% at full load
Environment, without derating
Ambient Temperature Range .... -20°F to 110°F
Stored Temperature Range .... -30°F to 150°F
IGBT Cooling System .... Liquid cooled
Compliance .... IEEE 519, IEEE 1547, UL 1741

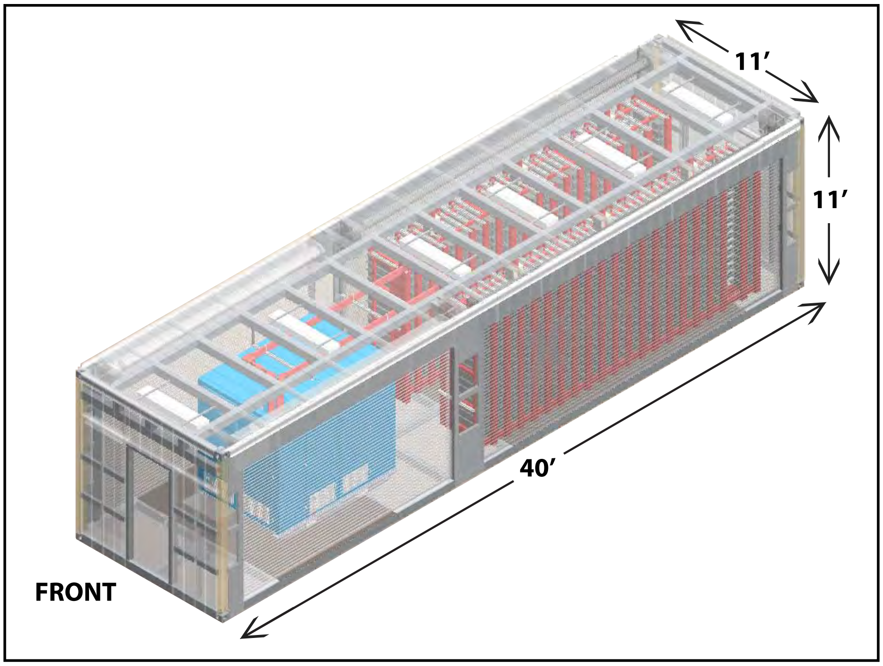
Control System Capabilities

- Multi-tiered Control System (SCADA, PLC, FCB) for Redundant Safety
- Fully Automated Sub Micro-second Response Time
- 24/7 Intelligent Fault Response System with Text Notification
- Real Time Remote Interface
- Comprehensive HMI for Total System Control & Real-Time Monitoring
- Auto & Manual Modes of Operation
- Flexible Programmable Response for Any Application Inputs
- Micro-second Data Acquisition & Historical Performance Data Logging
- Interoperability with External SCADA Devices
- Employs LAN for Component Communication within Control Room
- Remote Access through Secure VPN Connection

PowerCells™

Dimensions .... 30"L x 5"W x 5"H
Weight .... 54 lbs
Cell Voltage .... 12 VDC
Current .... 2,500 Amps for 30 seconds
Energy .... 1 kWh @ 3 hour rate
Instant Power Capacity .... 50 kW
Cycle Efficiency .... 95% - 99%
Cycle Life
@10% Depth of Discharge .... > 250,000 Warranty
@50% Depth of Discharge .... > 20,000 Warranty
Self Discharge Rate .... < 1% per month for 3 months
Ambient Temperature Range .... -20°F to 120°F without derating
Operating Temperature .... Ambient + 3°F
Environmental Impact .... Non-Hazmat Rated, 95% Recyclable Potential

As depicted in the CAD drawing, the power electronics (in blue) sit at the front of the DPR™ container. PowerCells™ are placed in two parallel racks (in red and black), each holding 500 kWh of storage. Controls (not illustrated) are placed on both sides of the front door.



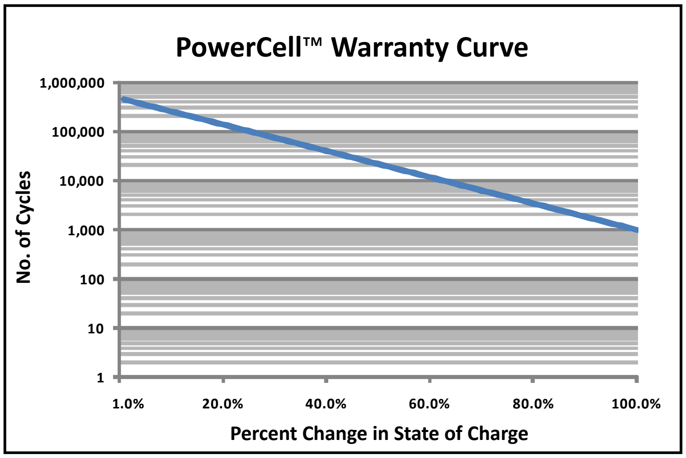
Between PowerCell™ Racks

Inside Power Electronics

Control System Cabinets

Container Exterior

While PowerCell™ life cycle is warranted according to the graph below, previous PowerCells™ have shown > 3,000,000 cycles in the field.



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White Paper

Public-Domain Test Data Showing Key Benefits and Applications of the UltraBattery®

January 2014

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Abbreviations Used in this Paper

Abbreviation	Meaning
AC	Alternating current
AEMO	Australian Energy Market Operator
ALABC	Advanced Lead Acid Battery Consortium
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DC–DC	To describe efficiency from direct current (DC) input to DC output
DoD	Depth of discharge
DOT	U.S. Department of Transportation
EUCAR	European Council for Automotive R&D
FCAS	Frequency control ancillary services
Diesel genset	Diesel generator set
HEV	Hybrid electric vehicle
Hz	Hertz (cycles per second)
IATA	International Air Transport Association
ISS	Idling-stop-start
kW	Kilowatt
Li-ion	Lithium Ion
mpg	Miles per gallon
MW	Megawatt
NEDO	New Energy and Industrial Technology Development Organization
NiMH	Nickel-metal hydride
PNM	Public Service Company of New Mexico
pSoC	Partial state of charge
PV	Photovoltaic
RAPS	Remote-area power supply
SHCHEVP	Simulated Honda Civic HEV profile
SoC	State of charge
SWER	Single-wire earth return
UPS	Uninterruptible power supply
V	Volt
VRLA	Valve-regulated lead-acid

Acknowledgements

This White Paper has been developed by Ecoult in order to identify the unique aspects of its UltraBattery® technology solutions by bringing together the various scientific tests carried out by major independent laboratories and by UltraBattery® manufacturers and system developers around the world.

Ecoult acknowledges and appreciates the significant input of scientist, writer and former CSIRO staffer Geoff James, who researched and wrote the original draft and was the leading external contributor to the paper.

Contents

1 Introduction

The UltraBattery® is a hybrid energy-storage device that combines a supercapacitor (alternatively called an ultracapacitor) and a lead-acid battery in single-unit cells, incorporating the best of both technologies and balancing their chemical and electrical characteristics passively: that is, without the need for extra electronic controls. The hybridization of the two technologies enhances the power and lifespan of the UltraBattery® compared to standard lead-acid batteries.

The result is an excellent multipurpose device, well suited to providing continuous variability management for the grid by operating in a partial state of charge that is also able to provide and absorb charge rapidly during acceleration and braking of a hybrid electric vehicle.

This White Paper has been prepared with a view to increasing awareness and understanding of the potential of this breakthrough technology by summarizing and linking sources of publicly available UltraBattery® test information. The data can be easily accessed and considered against the key benefits of the technology and against the market segments in which these benefits are important.

1.1 The Technical Breakthrough

The fundamental innovation of UltraBattery® technology, developed by Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO), is the introduction of an asymmetric supercapacitor inside a lead-acid battery (both storage methods using a common electrolyte) in a manner that modifies the behavior of the lead-acid battery chemistry to enhance power management and reduce negative plate sulfation (Figure 1).

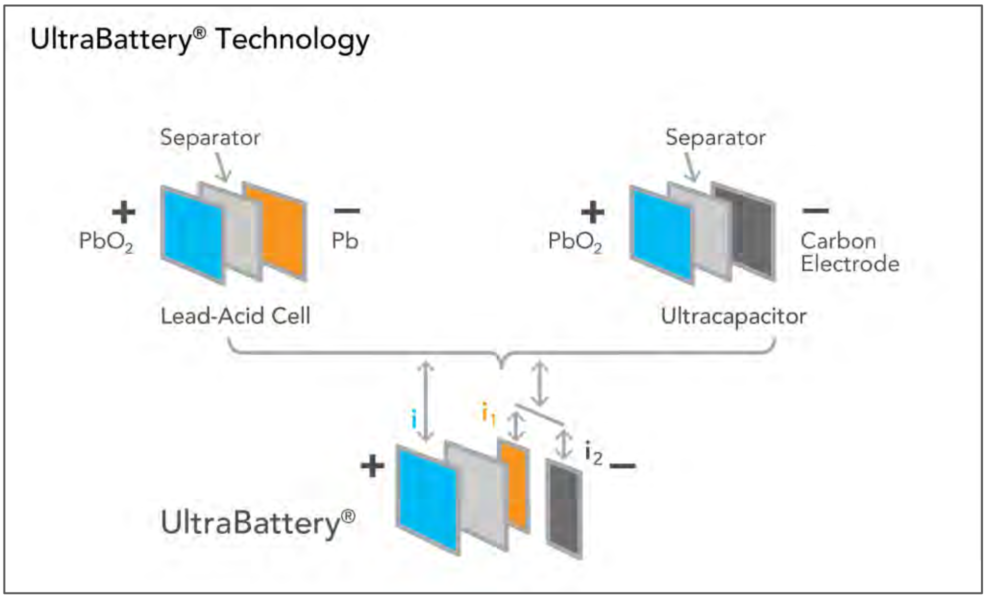

Figure 1: Schematics of standard lead-acid cell (top left), supercapacitor (top right) and their combination in the UltraBattery® cell (bottom)

The reduction of the rate of negative plate sulfation, which is the dominant cause of aging of valve-regulated lead-acid (VRLA) batteries when used in high-rate partial state of charge (pSoC), is achieved in UltraBattery® cells as an outcome of the carbon-based supercapacitor both being in parallel and sharing a common electrolyte with the negative electrode of the lead-acid cell.

1.2 UltraBattery® Testing Programs

The UltraBattery® breakthrough was quickly recognized for its potential to provide a safe and recyclable low-cost storage technology with existing mass-production facilities that could be used for active grid energy storage, electric and hybrid electric vehicles and renewable smoothing. Testing very quickly commenced in a wide number of government and commercial laboratories in the USA, Japan and Australia.

It was soon realized that the properties of the UltraBattery® supported outperformance across the full range of applications, and that this storage technology could provide solutions for both high-rate pSoC applications (such as renewable smoothing and grid ancillary services including voltage and frequency support) and for energy-shifting applications.

Of considerable further importance was the discovery that the supercapacitor and the lead-acid cell complemented each other in ways that made it possible to support these types of applications *simultaneously*, while additionally maintaining at all times capacity to support reserve events.

That is, an appropriately sized UltraBattery® string could be tasked with smoothing the output of a renewable generator, providing grid or microgrid voltage and frequency regulation, and being prepared to deliver a reserve power supply (such as in the manner of a UPS system) against grid outage events, all at the same time.

The first UltraBattery® cell produced outside of a laboratory setting was developed and tested in Japan at the Furukawa Battery Company in 2005–06, with the involvement of the CSIRO team including the inventor, CSIRO's Dr Lan Trieu Lam. This program was supported by the New Energy and Industrial Technology Development Organization (NEDO). An internal report (Furukawa & CSIRO, 2008) and company journal article (Furukawa, 2013) summarized the testing outcomes, including field tests in a Honda Insight hybrid electric vehicle (HEV) and at grid-integrated sites for the Kitakyushu Smart Community Creation Project. A journal paper (Furukawa et al., 2010) describes the cell-level and pack-level laboratory tests at the Furukawa Battery Company under several HEV duty cycles.

Three national laboratories in the USA have undertaken independent UltraBattery® testing programs for HEV and grid applications. At Idaho National Laboratories, comprehensive cycling tests under simulated HEV profiles (INL, 2012) culminated in retrofitting an UltraBattery® pack into a new Honda Civic HEV, which was subjected to dynamometer evaluation at Argonne National Laboratory and then to fleet operation in Phoenix, Arizona, where it accumulates approximately 5000 miles per month under a range of driving conditions (ALABC, 2013).

The Sandia National Laboratories provide reliable, independent, third-party testing and verification of advanced energy storage technologies from cells to MW-scale systems

(Ferreira et al., 2012). With the support of the US Department of Energy, they have demonstrated the longevity of the UltraBattery® under low-rate and high-rate cycling. This has resulted in detailed characterization for utility applications (Hund et al., 2008). Additional testing was also done at industry level under programs supported by the Advanced Lead Acid Battery Consortium (ALABC) and US battery manufacturer East Penn Manufacturing, which produces the UltraBattery® for both utility and HEV applications.

The longevity, high efficiency and long uptimes envisaged for the battery have been demonstrated in various deployments, often showing results exceeding the initial expectations of the inventors of the technology (such results have included hundred-thousand-mile-plus driving life, many thousands of full capacity cycles, and more than one million pSoC cycles during tests for HEV applications).

Much of the testing of the UltraBattery® has been done on a confidential basis by commercial enterprises and as such the results are not available. Nevertheless, a number of sources are in the public domain, and the most significant of these (published before October 2013) have been gathered to support this paper.

There are two major producers of UltraBattery® technology holding licenses to manufacture and commercialize the technology in different parts of the world. They are the Furukawa Battery Company (headquartered in Japan) and East Penn Manufacturing (headquartered in the USA). The products of both manufacturers have been subjected to rigorous testing programs, sometimes separately, and sometimes side-by-side in the same laboratory.

In Australia, testing has been supported by the Australian federal government through CSIRO, and by federal and state government grants through the Australian-based UltraBattery® solutions developer Ecoult Pty Ltd (now wholly owned by East Penn Manufacturing), at both laboratory level and demonstration scale.

UltraBattery® technology has already been successfully implemented in several MW-scale energy storage projects globally, delivering ancillary services, wind and solar smoothing and energy shifting. Initial test results and system outputs show the ability of UltraBattery® technology to deliver ancillary services more efficiently and economically than incumbent gas peakers, to successfully manage the ramp rate of large renewable energy plants, and to seamlessly combine renewable energy sources with a storage system.

The Public Service Company of New Mexico (PNM), the leading electric utility company in New Mexico, USA, has in collaboration with energy storage provider Ecoult, integrated an UltraBattery®-based storage system with a photovoltaic solar energy plant to demonstrate smoothing and shifting of volatile solar power and the ability to use the combination as a dispatchable renewable resource. The PNM Prosperity Energy Storage Project, funded with support of the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009 (ARRA), was the first solar storage facility in the USA to be fully integrated into a utility’s power grid. It features one of the largest combinations of battery storage and photovoltaic energy in the USA.

The PNM project has shown that energy shifting and smoothing can be very important to the power grid, particularly in altering the profile of grid-scale renewables. Tests had revealed that the 500 kW New Mexico solar photovoltaic (PV) array experienced ramp rates of 136 kW per second as solar energy was lost to cloud cover. Such large fluctuations in energy output can become unsustainable if renewable penetration increases. UltraBattery®

technology has successfully controlled and smoothed this PV output, and is demonstrating the viability of combining PV with a battery-based energy storage system.

Another USA-based project, also funded with support of the U.S. Department of Energy under the ARRA of 2009, has been an energy storage system that provides 3 MW of regulation services on the grid of PJM Interconnection, the largest of 10 Regional Transmission Organizations/Independent System Operators in the USA. The system, developed and integrated by East Penn Manufacturing through its subsidiary Ecoult, is also used for peak demand management, and provides continuous frequency regulation services bidding into the open market on PJM, responding to PJM's fast response signal. Traditionally much slower and less accurate gas-peaker plants are used for this service.

An application focus in Australia has been the use of UltraBattery® technology to support renewable energy integration and help maintain stability within island power grids with large renewable energy penetration. Work conducted by Ecoult and CSIRO culminated in a MW-scale facility for smoothing the output of a wind farm, about which several government reports have been published (see, for example, CSIRO, 2012). The success of this demonstration has in turn contributed to a commercial UltraBattery® deployment on King Island, a remote community of approximately 1700 people just south of the Australian mainland. The community is powered using a wind/diesel microgrid. Ecoult has developed and installed a 3 MW UltraBattery® storage solution for the island.

In Japan, the Furukawa Battery Company has developed UltraBattery® technology for HEV application and undertaken several HEV laboratory and field trials, which are discussed below.

Furukawa has also developed pilot and commercial projects for stationary storage applications for the Japanese market, concentrating on small-scale, grid-dispersed storage. It is increasingly likely that distributed storage will be a feature of future grids and, along with MW-scale developments, Ecoult, East Penn Manufacturing and the Furukawa Battery Company continue to develop and enhance UltraBattery® systems in the kW range.

Furukawa projects include a storage system for a corporate microgrid (a 'smart' building), which has been developed for Shimizu Corporation. The 500 Ah smart building application uses 163 UltraBattery® cells, each rated at 2 V. A 'battery condition watcher' installed in the energy storage system monitors cell voltage, impedance and temperature.

Two load-leveling trials have also recently been established, the first at Furukawa's own Iwaki Factory, where the company has set up a smart grid demonstration of UltraBattery® technology to control the factory's demand for electric power. The load-leveling application involves 192 UltraBattery® cells, a 100 kW power conditioning system and battery management software. The second trial is a 300 kW smart grid demonstration system of UltraBattery® technology using 336 UltraBattery® cells (1000 Ah, 2 V), which has been installed in the Maeda area in Kitakyushu.

Two community-level energy storage projects have also been installed at Kitakyushu, within the Kitakyushu Museum of Natural History and Human History. Both projects are designed for peak shifting, and indicate that the UltraBattery® is a suitable technology for the development of long-anticipated distributed storage throughout the grid. The first of the two projects is a 10 kW facility peak shifting application that uses 32 UltraBattery® cells (100 Ah, 6 V). The second is a 100 kW facility peak shifting application that uses 192 UltraBattery® cells (500 Ah, 2 V).

Storage systems based on UltraBattery® technology have now been deployed by Furukawa, East Penn, and Ecoult into a large number of grid and microgrid scaled power networks to manage variability, shift energy for grid stability, and enhance the utilization of renewable generation sources. The UltraBattery® is also advanced in the certification process of major automotive manufacturers. Generic products and solutions based on the UltraBattery® are being released progressively globally.

1.3 Publicly Available Research Considered

The following reports were considered in the preparation of this White Paper. Full details, including URLs where available, are provided in the References section at the end of this paper. The reports are shown here in reverse order of publication, and when interpreting some of the earlier results it should be remembered that UltraBattery® technology has advanced during the time covered by these reports. Figure 9 on page 24 provides a graphical summary of some such advancements.

Title	Author(s), Year	Summary
ALABC UltraBattery Hybrid Surpasses 100,000 Miles of Fleet Duty	ALABC, 2013	Document marking 100,000 miles of real-world fleet duty by a Honda Civic HEV with an UltraBattery® pack, achieved with minimal capacity loss
Development of UltraBattery	Furukawa, 2013	Paper in the *Furukawa Review* describing laboratory tests of UltraBattery® using profiles representing micro-HEV usage and stationary shifting and smoothing; charge–discharge voltages and the relation between longevity and efficiency and state of charge are explored in some depth
UltraBattery Energy Storage System for Hampton Wind Farm Field Trial: Summary of Activities and Outcomes	CSIRO, 2012	Comprehensive report on installing, commissioning, and operating a MW-scale UltraBattery® for smoothing wind farm output, with observations of battery performance; the voltage stability in a string of cells is particularly impressive
Development and Testing of an UltraBattery-Equipped Honda Civic Hybrid	INL, 2012	Comprehensive report on the development, testing, and fleet-vehicle operation of an UltraBattery® pack, with detailed comparative measurements of an NiMH battery pack and two UltraBattery® packs

Title	Author(s), Year	Summary
Life Cycle Testing and Evaluation of Energy Storage Devices	Ferreira, Baca, Hund, & Rose, 2012	Presentation on activities in the Sandia Energy Storage System Analysis Laboratory including high-rate and low-rate UltraBattery® longevity tests, using combined cycle profiles, which are relevant for utility and renewable energy applications
Further demonstration of the VRLA-type UltraBattery under medium-HEV duty and development of the flooded-type UltraBattery for micro-HEV applications	Furukawa, Takada, Monma, & Lam, 2010	Peer-reviewed journal paper on cell-level and string-level UltraBattery® testing, with emphasis on discharge voltage performance under several cycle-life test profiles, including high-temperature operation
UltraBattery Test Results for Utility Cycling Applications	Hund, Clark, & Baca, 2008	Conference paper from the Sandia team focusing on utility applications enabled by large-format UltraBattery® cells; provides detailed charge and discharge voltage behavior during pSoC cycling at different rates, from 1C to 4C
Development of UltraBattery: 3rd Report	Furukawa & CSIRO, 2008	Report showing extremely long cycle life, without recovery charging, of a 144 V UltraBattery® pack for micro- and medium HEV operation; includes direct comparison with conventional and idle-stop batteries as well as a simple wind energy-shifting profile

2 Value Proposition

The value proposition for the UltraBattery® is that it outperforms other lead-acid battery technologies in several important areas, including:

+ **Total lifetime energy throughput capacity for management of power variability**
  leading to lower lifetime cost per kWh
+ **Ability to operate continuously in a pSoC regime (i.e. operating in a band of charge that is neither totally full nor totally empty)**
  leading to viability of use models where energy is charged and discharged at significantly higher efficiency
+ **Charge acceptance (matched to discharge rate capability)**
  leading to quicker recharge
+ **Consistency of behavior of individual cells in long strings**
  leading to lower maintenance.

UltraBattery® technology can be used to continually manage energy intermittencies, smooth power and shift energy. As noted above, it combines the advantages of proven and dependable advanced lead-acid battery technology with the advantages of an asymmetric supercapacitor, enabling the optimal balance of an energy-storing lead-acid battery with the quick charge acceptance, power discharge and longevity of a supercapacitor. It is a competitive alternative to non-lead-acid battery technologies, which the UltraBattery® matches or exceeds for applications that manage power variability in second and minute timeframes as well as for energy-shifting applications of 1 to 4 hours.

The UltraBattery® cell has characteristics that make it resistant to many of the typical failure modes that make conventional lead-acid batteries unsuitable for certain applications, giving UltraBattery® technology a comparatively wider range of potential applications and a longer useful life. Standard valve-regulated lead-acid (VRLA) batteries form ‘hard’ lead sulfate deposits inside and on the surface of the porous negative plate when operated continuously in a pSoC regime, unless given frequent refresh overcharge cycles. However, the capacitor integrated into the UltraBattery® modifies the process associated with the formation and dissolution of sulfate crystals within the negative plate when discharging and charging, respectively. This enables the UltraBattery® cell to operate for long periods in the mid-charge band (the most efficient charge/discharge region for lead-acid cells) and, combined with the cycling endurance of the technology, results in an ability to process a much greater amount of energy (a significant multiple over standard lead-acid technology) in the device’s usable lifetime.

This capability is fundamental to the technology’s ability to meet typical grid requirements for smoothing the variable output of renewable generators and for shifting energy from periods of high production to periods of high demand.

The ability to work in constant pSoC is also crucial for HEV energy storage, where braking and acceleration occur in rapid repetition. UltraBattery® technology shows comparable performance (in miles per gallon terms) to that of a vehicle of the same model powered by nickel-metal hydride (NiMH) batteries, at significantly lower cost (ALABC, 2013). Furthermore, longevity, safety, efficiency, long uptimes, and full recyclability all point to potentially competitive triple-bottom-line advantages for UltraBattery® technology over chemistries whose safety and recyclability are yet to be demonstrated. The following table shows which publicly available test results support the UltraBattery® capabilities that comprise its value proposition.

Source of Test Data	High-Capacity Turnover/Longevity	Lower Lifetime Cost per kWh	High Efficiency	Fewer Refresh Cycles	Less Downtime	High Charge Acceptance	Lower Variability of Cell Voltage within Strings
ALABC, 2013	x	x					x
CSIRO, 2012							x
Ferreira et al., 2012	x	x		x	x		
Furukawa, 2013	x	x	x			x	
Furukawa & CSIRO, 2008	x	x					x
Furukawa et al., 2010							x
Hund et al., 2008	x	x				x	
INL, 2012	x	x	x	x	x		

3 Application Matrix Indicating Use Cases for UltraBattery® Technology

Each application of UltraBattery® technology has specific requirements that are met by different aspects of the value proposition. The following table maps applications to the publicly available test results that support the value proposition. For the most part, applications require either energy shifting at a low charging or discharging rate, or high-rate cycling at an intermediate or partial state of charge, with some requiring a mixture of these capabilities.

The table marks the applications that have been directly targeted by testing programs, using cycle profiles that represent typical operation. Some applications have not yet been explicitly represented in testing programs. This may be because earlier testing concentrated on applications that were considered more commercially relevant, or because some applications have only recently been envisaged and understood. New testing programs are underway to address a wider set of applications (see, for example, Ferguson, 2013).

While the columns headed 'Power quality' and 'Residential energy management' are empty, they have been included here because both applications are at an advanced stage of commercial development by Ecoult (with some projects installed and operational), since internal tests and extrapolations from other testing have shown the technology to be very well suited to these applications. Similarly, the 'Railways' column is also blank, indicating that no specific testing has been performed on this application. However, on the basis of tests performed in other areas it is considered that UltraBattery® technology is well suited to supporting the very demanding requirements of railway energy management. A later section of this paper discusses railway requirements in greater detail.

Source of Test Data	Frequency Regulation	Smoothing and Ramp-Rate Control	Power Quality	Spinning Reserve	Residential Energy Management	Energy Shifting and Demand Management	Diesel Efficiencies	Multipurpose use in Datacenters and Commercial Buildings	Micro- and Medium HEVs	Railways
ALABC, 2013									x	
CSIRO, 2012		x								
Ferreira et al., 2012	x	x		x		x	x	x		
Furukawa, 2013		x				x		x	x	
Furukawa & CSIRO, 2008									x	
Furukawa et al., 2010									x	
Hund et al., 2008	x	x				x		x		
INL, 2012									x	

4 Tests Supporting the UltraBattery® Value Proposition

The publicly available test results that support the value proposition are here described in detail, so that they may be compared to the value proposition above and to the application requirements in a later section.

4.1 High-Capacity Turnover and Longevity

4.1.1 Defining Cycles and Capacity Turnover

The outstanding benefit of the UltraBattery® cell is its long life under cycling operations at pSoC. Quantifying this for disparate applications requires a definition of 'capacity turnover' that is separate from the concept of a 'cycle'.

The common understanding of a cycle is a charging operation followed by a discharging operation, so that a new cycle is marked by a change in direction of power flow into or out of the cell, and not by a particular amount of energy stored and released. The full nameplate capacity of a battery is rarely or never used in a single cycle. Thus, although it is common to count cycles during a test, this is not a measure that can be compared between different tests that may use different application-specific cycles.

Capacity turnover measures the total energy throughput of a battery, up to the end of its life, as a multiple of the rated capacity of a battery. A comparison of battery life cycles becomes possible by comparing capacity turnovers. The UltraBattery® cell has a very large capacity turnover, exceeding by around four times (and in some applications by many more times) the capacity turnover of the best-performing VRLA batteries, as demonstrated in the tests described below.

Many tests have quantified the lifetime of the UltraBattery® for either vehicular or utility applications. It is useful to divide the tests into those that are high-rate and low-rate compared to the '1C' rate that would discharge the battery in 1 hour, and this terminology will be used in the following test summaries.

+ A high-rate test charges and discharges at the order of a 1C rate, and each cycle lasts for some minutes, therefore having a small depth of discharge (DoD) impact.
+ A low-rate test charges and discharges at a fraction of the 1C rate, and each cycle may last for some hours, therefore having a significant DoD impact.

High-rate tests usually represent 'balancing' applications for which responsive power delivery is required, as in HEVs, renewable energy smoothing, or regulation services. Low-rate tests usually represent 'energy-shifting' applications.

A battery is generally considered to have reached the end of its useful life when its available capacity is reduced to 70-80% of its nameplate capacity. It is quite possible, however, that such a battery may be repurposed to find continued use in another application, and offered at a lower price point than a new battery.

4.1.2 Longevity Tests by the Sandia National Laboratories

The Sandia National Laboratories have performed independent testing that has drawn substantial positive attention to UltraBattery® technology (Ferreira et al., 2012). The team at Sandia tested UltraBattery® cells made by both Furukawa and East Penn.

The test profile for high-rate, pSoC cycling represented a utility application with cycles of 5% DoD. An East Penn UltraBattery® ran for more than 20,000 cycles maintaining very close to 100% of its initial capacity, as shown in Figure 2. By comparison, the conventional VRLA battery fell below 80% of its initial capacity after approximately 2500 cycles.

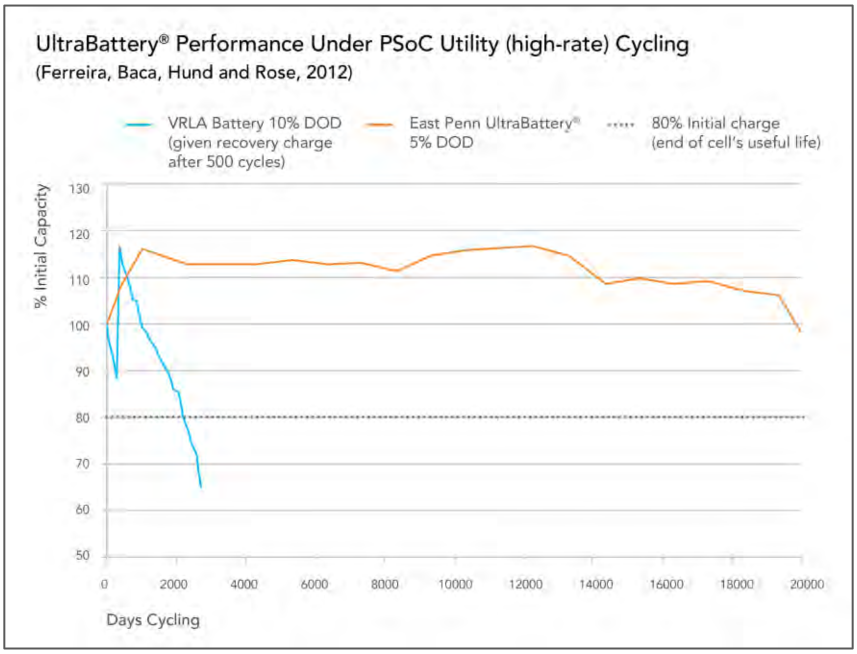

Figure 2: UltraBattery® performance under pSoC utility (high-rate) cycling (Ferreira et al., 2012)

Under the test profile for slow, low-rate, high-energy cycling, which is a PV hybrid test schedule, UltraBattery® cells manufactured by East Penn and Furukawa showed performance far exceeding that of traditional VRLA batteries, as shown in Figure 3. This performance was achieved even after 40 days without a recovery charge to 100% SoC (where a recovery charge is generally needed much more frequently to alleviate sulfation in conventional lead-acid cells).

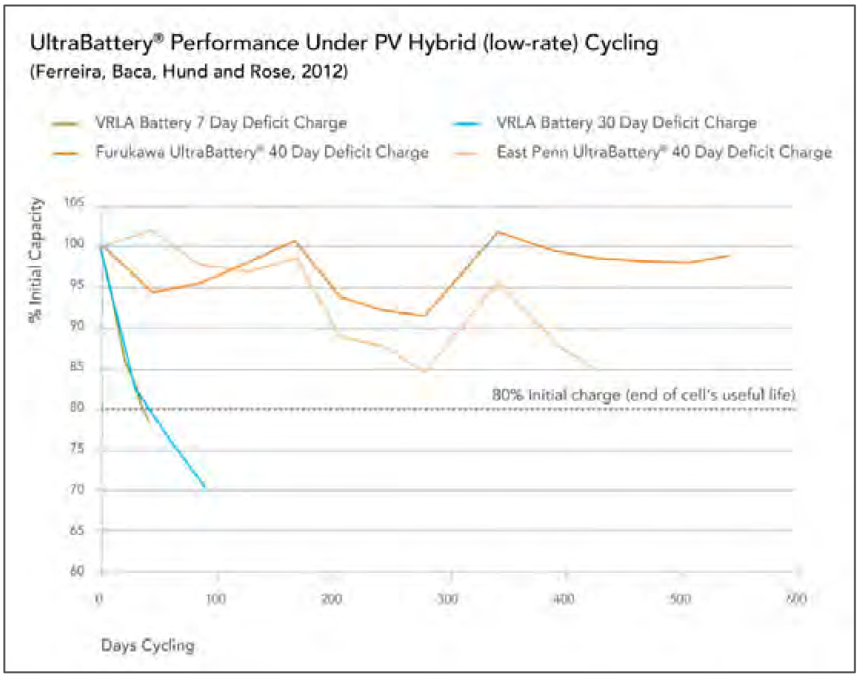

Figure 3: UltraBattery® performance under PV hybrid (low-rate) cycling (Ferreira et al., 2012)

These tests used large-format UltraBattery® units from East Penn and Furukawa designed for utility applications. Results of earlier high-rate pSoC cycling tests representative of regulation services performed by Hund et al. (2008) are shown in Figure 4. These used smaller-format Furukawa UltraBattery® cells and, this should be factored into consideration when comparing the performance but, together they show that the longevity of the cells was evident from the earliest publicly available tests across different applications and cell configurations.

Hund et al.'s 2008 tests were designed to expose the cells to groups of 100 or 1000 rapid charge–discharge cycles at a 1C, 2C, or 4C rate, covering a range of 10% DoD, separated by recovery charging at 1C for a capacity measurement, and then discharging at 1C to 50% SoC for the next group of rapid cycles.

As shown in Figure 4, the UltraBattery® cells lasted approximately 13 times longer (16,740 cycles) than the absorbed glass matt VRLA battery (1100 cycles). The UltraBattery® cells were also able to withstand more than 10 times the number of rapid cycles as compared to the VRLA battery (1000 vs 100) before a recovery charge.

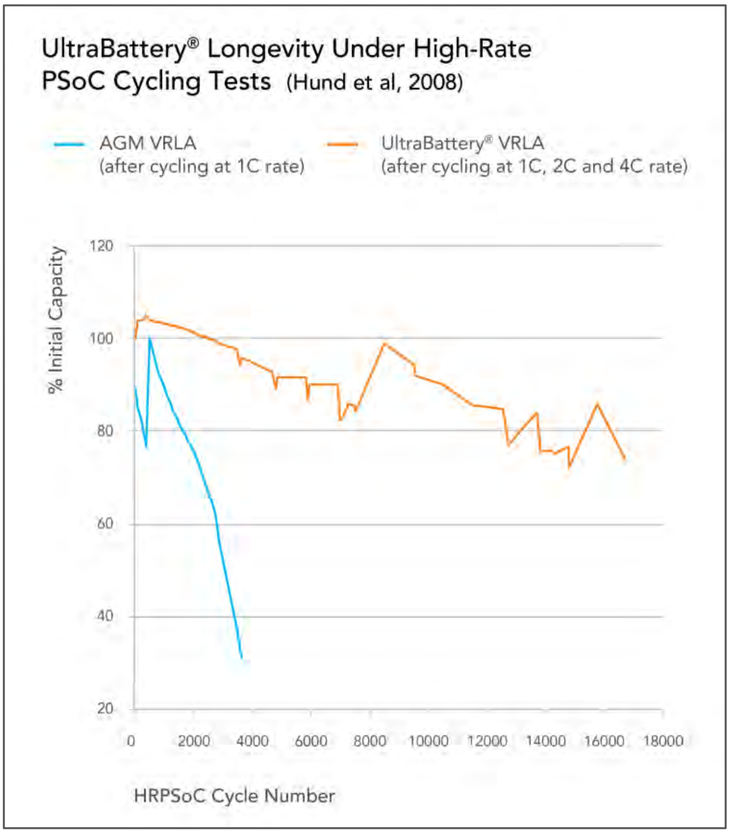

Figure 4: UltraBattery® longevity under earlier high-rate pSoC cycling tests (Hund et al., 2008)

The voltage and capacity chart for the UltraBattery® is shown in Figure 5, illustrating characteristics during charge and discharge before the first high-rate pSoC cycle (green trace), after 500 cycles (blue trace), and after 16,740 high-rate pSoC cycles (red trace).

At an initial capacity of 7.8 Ah, the UltraBattery® exceeded the manufacturer's specified capacity of 6.67 Ah (117% of rated capacity). After 500 cycles, the capacity *increased* to 8.1 Ah (121% of rated capacity). Such an increase in capacity, while unusual in lead-acid cells, is typically seen in UltraBattery® cells at the onset of testing and use (in more recent testing, following improvements to the cells, this increase is far more marked and long-lasting). The capacity after 16,740 cycles was 5.8 Ah. This is 87% of rated capacity, so the battery was still considered to be well within its useful life at the conclusion of testing.

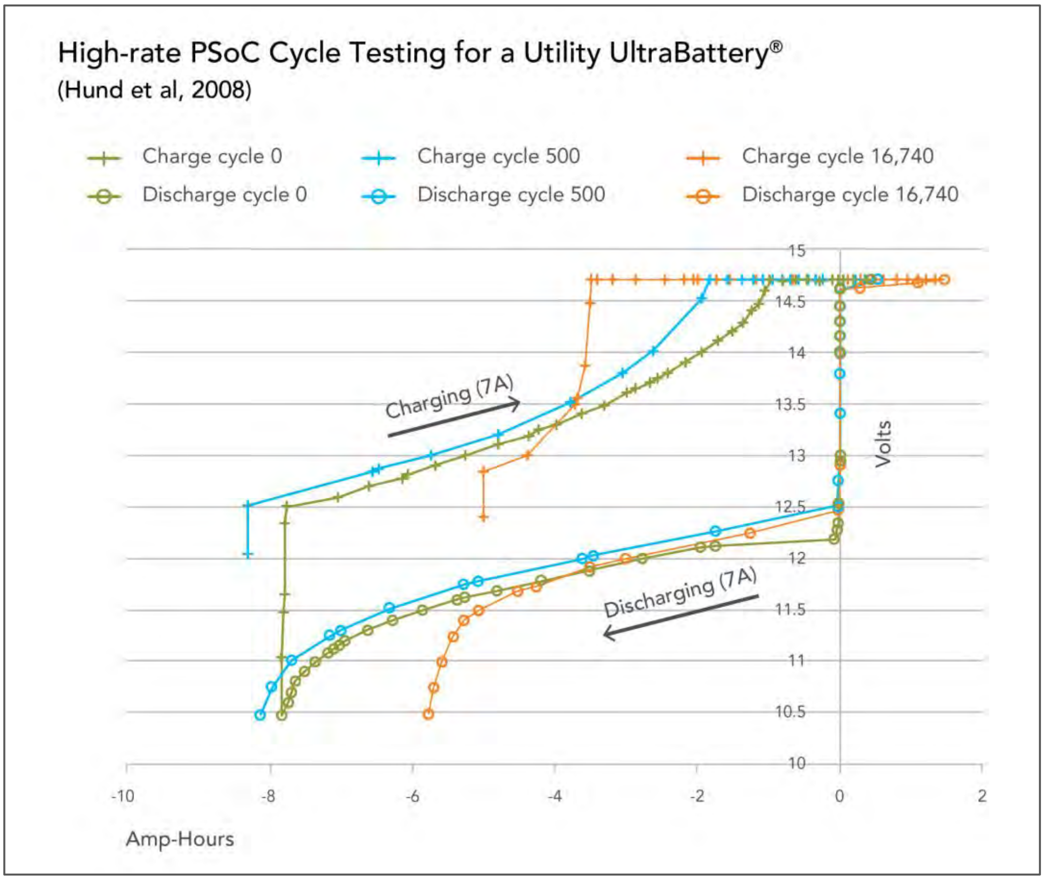

Figure 5: High-rate pSoC cycle testing for a utility UltraBattery®. The lower three traces show discharging; the upper three show charging. Note that the charge and discharge are 'looped'. The green loop plots the measurements on the first charge–discharge cycle. The blue loop represents the 500th charge–discharge cycle and shows an increased capacity on the starting cycle. The red loop represents the 16,740th charge–discharge cycle, and shows that some reduction in capacity has taken place (Hund et al., 2008).

4.1.3 Longevity Tests by the Furukawa Battery Company

The Furukawa Battery Company has manufactured UltraBattery® cells for both micro-HEV and utility applications, and has pursued a thorough testing program in parallel (Furukawa, 2013). Batteries in micro-HEVs are used differently from standard car batteries in the following three main respects.

+ They should withstand deeper discharge so they can power the car's electrical systems when the engine stops idling.

- They should withstand a larger number of deep-current discharges to start the motor again each time it stops idling.
- They should operate at about 90% SoC so there is some headroom to accept current from regenerative braking.

A cycling test that exhibited these characteristics was applied to a Furukawa UltraBattery® and to a conventional lead-acid battery designed for micro-HEV use (Furukawa, 2013). This test used a 5% DoD and was performed at three different states of charge. As the SoC increased from 70% to 90%, the capacity turnover increased from 530 to 720, as shown in Figure 6. The UltraBattery® unit had approximately 1.8 times as much capacity turnover as the conventional battery under the condition of 70% SoC. The conventional battery was not tested at 80% or 90% SoC.

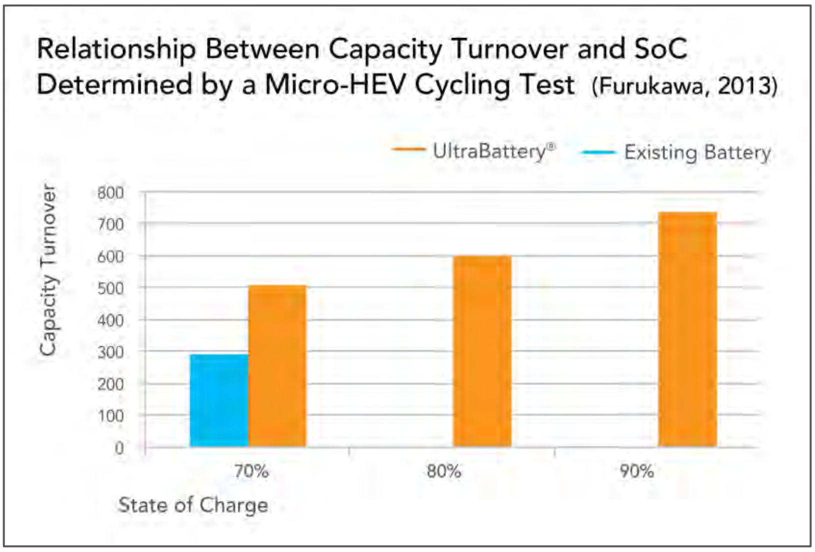

Figure 6: The relationship between capacity turnover and SoC determined by a micro-HEV cycling test (Furukawa, 2013)

After testing, the batteries were dismantled for analysis. The conventional battery showed significantly sulfated negative active materials, whereas the UltraBattery® cells showed little negative electrode sulfation. This is one of the reasons why the UltraBattery® exhibits good lifetime characteristics, as negative plate degradation is a significant failure mode in conventional VRLA batteries used for pSoC applications.

Furukawa also performed tests designed to show that UltraBattery® technology was suited to utility applications. A Furukawa UltraBattery® unit was subjected to a high-rate pSoC cycle test, following a very similar pattern to the Sandia National Laboratories test described above. After adjusting the SoC to 50% at 1C charge current, there was a group of 1000 charge–discharge cycles at a 1C rate for 6 minutes in each direction, covering therefore a 10% DoD, with a break for 5 minutes between each direction. Groups were repeated to end of life, separated by a 1C charge and capacity test.

Compared at the point where the capacity ratios dropped to 80%, the life of the UltraBattery® cell is twice as long as that of the existing lead storage battery, as can be seen in Figure 7.

This doubling of life expectancy is a significant performance advantage (although the Furukawa cell has shown significantly better performance in other tests, including those noted below which show the cell still operating successfully after an extraordinary 1.4 million cycles.)

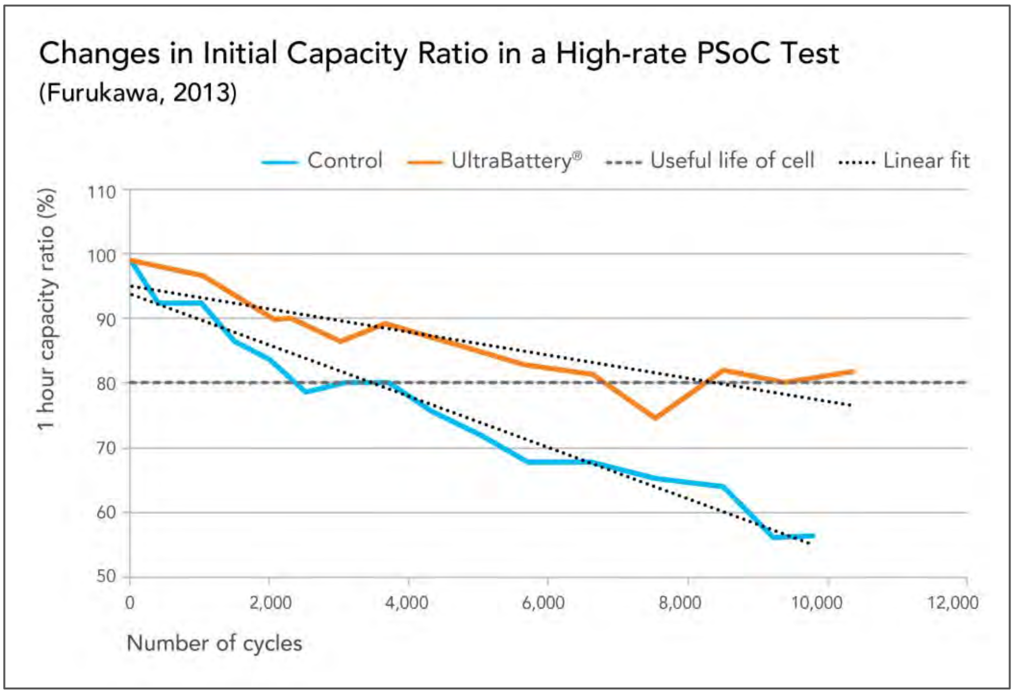

Figure 7: Changes in initial capacity ratio in a high-rate pSoC test (Furukawa, 2013)

4.1.4 Medium-HEV Field Testing by CSIRO and the Furukawa Battery Company

The suitability of the UltraBattery® cell for vehicular applications has been demonstrated by two long-distance driving tests as well as by laboratory cycling tests.

The first driving test was carried out on a test circuit in January 2008. A 144 V module using prototype Furukawa UltraBattery® cells was installed in a Honda Insight HEV, and a drive of 100,000 miles (160,000 km) was achieved without recovery charging. Remarkably, the UltraBattery® cells remained in good condition after the drive (Furukawa & CSIRO, 2008).

Of particular significance is that this field driving test demonstrated no difference between the driving performance of the HEV using the UltraBattery® pack and that of the HEV using the NiMH battery pack. It has also been shown that the cost of the UltraBattery® cells was dramatically less than that of the NiMH cells, and that fuel efficiency and carbon dioxide emissions were almost the same between the two cell chemistries.

To follow up and further quantify the road test results, a laboratory cycle-life test was conducted for the 2 V cell flooded type Furukawa UltraBattery® based on the power-assisting EUCAR profile (Furukawa & CSIRO, 2008; Furukawa et al., 2010). The test was started at 60% SoC, and no recovering charging was done. The life of the UltraBattery® cell, however, was more than 40,000 cycles, representing a cycle life more than 10 times longer than that of a conventional lead-acid battery, and more than four times longer than that of a lead-acid battery designed for idling-stop-start (ISS) vehicles. This comparison is shown in Figure 8.

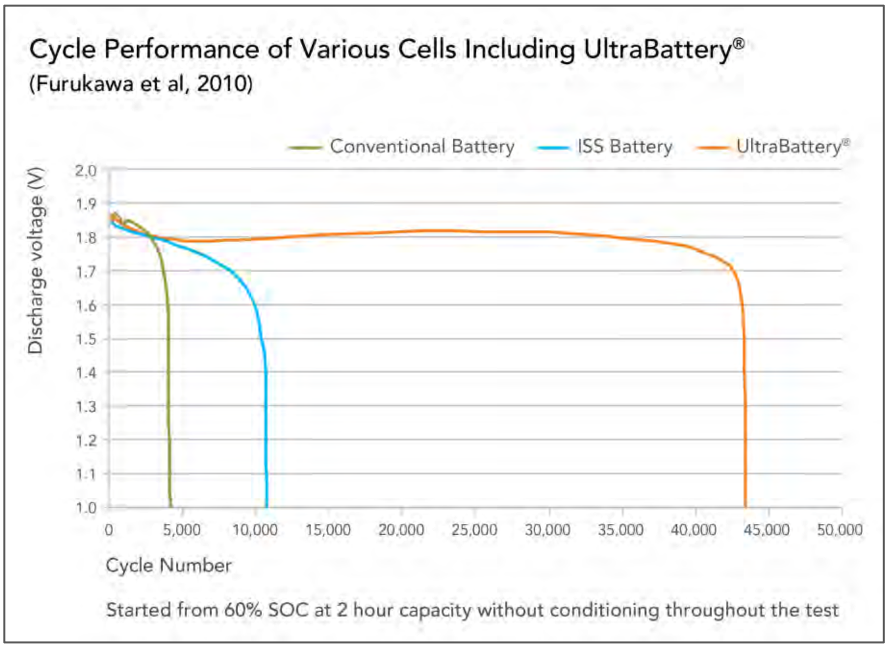

Figure 8: Cycle performance of a conventional battery, an ISS battery, and an UltraBattery® under the power-assisting EUCAR profile (Furukawa et al., 2010)

Another laboratory life-cycle test was performed with a 12 V unit (six 2 V UltraBattery® cells packaged in the manner of commonly observed 12 V industrial lead-acid batteries) with five-hour capacity of 8.5 Ah connected in series to make a 144 V battery pack (Furukawa et al., 2010). The battery pack was then cycled under a simulated, medium-HEV profile. This profile comprised 10 cycles, with each cycle comprising several discharge and charge steps of different rates and durations.

The average time of one cycle in the profile was 33 s, and the discharge–charge window was approximately 0.35% of the nominal five-hour capacity. From a fully charged state, the UltraBattery® pack was discharged at five-hour rate to 60% SoC and then subjected repetitively to the above profile for five days, followed by two days resting at open circuit. This simulates a week of car use for commuting. This 'test week' was then repeated, with no conditioning or equalization charge.

At the time of publication of the report (Furukawa et al., 2010), after two years of testing the UltraBattery® pack had already passed 1,400,000 cycles, which is seven times greater than the target value of 200,000 cycles. The capacity turnover corresponding to this number of cycles is 5000 (that is, the full capacity of the cells has been turned over 5000 times during the test). No major decrease in the pack voltage was observed, despite no conditioning or equalization charge being performed during the test.

4.1.5 Medium-HEV Field Testing by the Idaho National Laboratory

The second driving test used a fleet vehicle experiencing real road conditions. The Idaho National Laboratory (INL, 2012) undertook this test within the UltraBattery® Retrofit Project

DP1.8 and Carbon Enriched Project C3, performed by ECOtality North America and funded by the US Department of Energy and ALABC. These tests were established to demonstrate the suitability of advanced lead-acid battery technology in HEVs.

In preparation for this driving test, a Furukawa UltraBattery® pack operated trouble free for 60,000 simulated miles (96,000 km) under Simulated Honda Civic HEV Profile (SHCHEVP) at 30°C (86°F), with minimal drop in performance. A vehicle-sized pack of East Penn UltraBattery® packs also delivered 60,000 miles under SHCHEVP at 30°C. The simulation allowed tests to be performed in laboratory conditions but was calibrated against cells housed in actual HEVs, and the lab and field tests were shown to produce virtually identical results.

The UltraBattery® modules showed remarkably low rates of voltage divergence: all cells remained very close to each other in performance and capacity throughout their lifetimes. Logging of individual 12 V modules showed that less than one-quarter of a volt separated all modules at the end of more than 45,000 miles (72,000 km) of simulated driving.

These results are very promising and, combined with the results for the individual module cycling, they suggest that a single UltraBattery® pack may be capable of lasting the design life of a modern HEV (160,000 miles or 260,000 km). To compare UltraBattery® performance against other advanced lead-acid cell designs, a vehicle-sized pack of high-carbon ALABC lead-acid modules (not UltraBattery® cells) was operated under SHCHEVP, and it failed after 27,000 simulated miles (43,500 km). A vehicle-sized, high-carbon, lead-acid battery from Exide was also cycled under SHCHEVP, but it failed after 12,500 simulated miles (20,000 km) (INL, 2012).

In October 2011, the converted HEV using an East Penn UltraBattery® pack was put into ECOtality's fleet of test vehicles in Phoenix, Arizona, and it is currently accumulating approximately 5000 miles (8000 km) per month. At the end of August 2012, the vehicle had accumulated more than 60,000 miles and had experienced a wide range of driving conditions and demanding ambient temperatures. The battery capacity was measured at 7.54 Ah (at a C1 rate) after 51,000 miles (82,000 km) of driving, which is an insignificant capacity loss against the average capacity of the new modules, which is 7.55 Ah.

By June 2013, the converted HEV had recorded more than 100,000 miles (160,000 km) of courier duty in the local area of Phoenix, Arizona. The HEV demonstrator achieved the benchmark in the varying temperatures and elevations of the Phoenix area in just under two years of operation with no significant loss in battery capacity.

4.2 Chronology of All Longevity Tests Discussed in this Paper

UltraBattery® technology has been continuously developed since its invention, with further innovations from CSIRO and the technology's two manufacturers applied to each new version of the product. This means that test results from different laboratories at different times may not be directly comparable. Because longevity tests have been the most frequently performed of all UltraBattery® characterizations, the table below compares the longevity results from several sources of test data, in order of date of publication of the results.

A significant increase in performance over traditional VRLA technology is evident in all the test results. However, due to the very wide range of test conditions (such as cycling profile, temperature, cell configuration and refresh charging regime), these results also are not necessarily directly comparable.

Developments in UltraBattery® technology over time are not necessarily discernible within the range of results shown in the table below. However, if the most recent internal testing is included then the trend toward greater energy throughput in the lifetime of the UltraBattery® cell is very clear (see Figure 9, below).

Source	Year	Manufacturer	Cycling Depth	Rate	Lifetime*	Conventional Lead-Acid	Ratio	Notes
Hund et al., 2008	2008	Furukawa	10%	High	16,740 c	1,100 c	15.2	
Furukawa et al., 2010	2010	Furukawa 2V	n/a	Low	43,000 c	4,000 c	10.8	
Furukawa et al., 2010	2010	Furukawa flooded cell	n/a	High	75,000 c	15,000 c	5.0	ISS cycle
Furukawa et al., 2010	2010	Furukawa flooded cell	n/a	High	8,000 c	2,000 c	4.0	
Ferreira et al., 2012	2012	East Penn	5%	High	>20,000 c	2,500 c	8.0	
Ferreira et al., 2012	2012	Furukawa	5%	High	5,000 c	2,500 c	2.0	High temp.
Ferreira et al., 2012	2012	East Penn	n/a	Low	> 430 d	40 d	10.8	
Ferreira et al., 2012	2012	Furukawa	n/a	Low	> 550 d	40 d	13.8	
INL, 2012	2012	Furukawa	10%	HEV	> 60,000 mi	12,500–27,000 mi	2.2–4.8	
INL, 2012	2012	East Penn	10%	HEV	> 60,000 mi	12,500–27,000 mi	2.2–4.8	

INL, 2012	2012	East Penn	10%	HEV	167,000 mi	40,391 mi	4.1
Furukawa, 2013	2013	Furukawa	5%	Low	720 t	290 t	2.5
Furukawa, 2013	2013	Furukawa	10%	High	8,800 c	3,700 c	2.4

* Measured in days (d), cycles (c), capacity turnover (t), or HEV miles (mi)

The trace marked Sandia UB12 in Figure 9 shows UltraBattery® results from the Sandia National Laboratories from 2008. These are very similar to many pre-2013 results for UltraBattery® cells. Note that Li-ion testing performed concurrently showed UltraBattery® technology to be on par with the Li-ion tests at the time. The most recent testing performed internally in 2013 (by Ecoult and East Penn Manufacturing) is indicated by the top three traces in Figure 9, and illustrates the significant improvements made to UltraBattery® technology in the past few years.

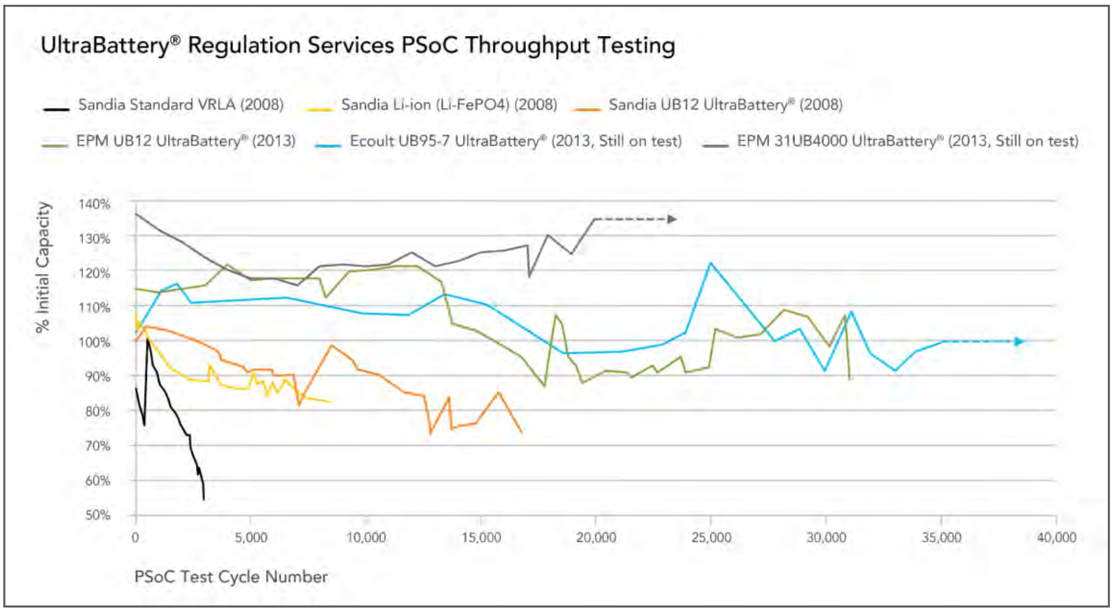

Figure 9: Energy throughput testing showing Sandia National Laboratories results from 2008 (lower three traces) for VRLA, UltraBattery® (UB12) and Li-Ion test results. The Sandia results are compared against internal testing carried out by Ecoult and East Penn Manufacturing (top three traces) performed in mid-2013. There is a clear trend toward increasing throughput as the UltraBattery® cells are improved over time.

4.3 Lower Lifetime Cost per kWh Delivered

As a consequence of high-capacity turnover and longevity, UltraBattery® cells need less frequent replacements than VRLA batteries in active power applications, and can have a much greater energy throughput during their lifetimes. Therefore the cost relative to the throughput, measured per kWh delivered, is significantly lower.

The actual cost per kWh delivered depends on the cycling pattern required by the application. For example, using estimated cycling requirements for frequency control ancillary services (FCAS) in Australia (in costings done for the Tasmanian market), the UltraBattery® was the only technology that would deliver a profit in this application (James & Hayward, 2012). (Note that in that report the UltraBattery® is referred to as an 'advanced lead-acid battery'. However, this is not strictly accurate since this term is usually used to describe a type of storage device with no supercapacitive chemistry and with different characteristics from the UltraBattery®.)

An end-to-end calculation of the fuel efficiency of a Honda Civic HEV using an UltraBattery® pack (ALABC, 2013) shows that this car has achieved comparable mpg performance with that of the same model powered by NiMH batteries but at a significantly lower cost.

4.4 High Efficiency

The UltraBattery® cell achieves typical DC–DC efficiency of 93–95% when performing variability management applications such as regulation services or renewable ramp rate smoothing at 1C peak power in a pSoC regime.

The UltraBattery® also achieves typical DC–DC efficiency of between 86% and 95% (rate dependent) when performing energy-shifting applications in pSoC. This high efficiency compares favorably with the typical efficiency of less than 70% when standard VRLA batteries are applied to energy shifting using the typical top-of-charge regime.

Efficiency testing was undertaken at the Furukawa Battery Company for 2 V UltraBattery® cells with capacity 1000 Ah at a 10-hour rate, intended for stationary applications (Furukawa, 2013). The SoC was adjusted in increments of 10%, and 30 charge–discharge cycles were performed at rates of between 0.1C and 0.6C, followed by a recovery charge.

During cycling the quantity of charge–discharge electricity was equivalent to 10% of the rated capacity, ensuring that the efficiency measurement was not dominated by the SoC adjustment and recovery charging, thereby providing acceptable accuracy. The stationary UltraBattery® showed Wh efficiencies of 91–94.5% for 0.1C charge–discharge cycling, and of 83–87% for 0.45C–0.6C charge–discharge cycling, for SoC in the range of 30–90% as shown in Figure 10.

Thus, the UltraBattery® demonstrated high Wh efficiencies not only for low charge–discharge currents but also for high charge–discharge currents.

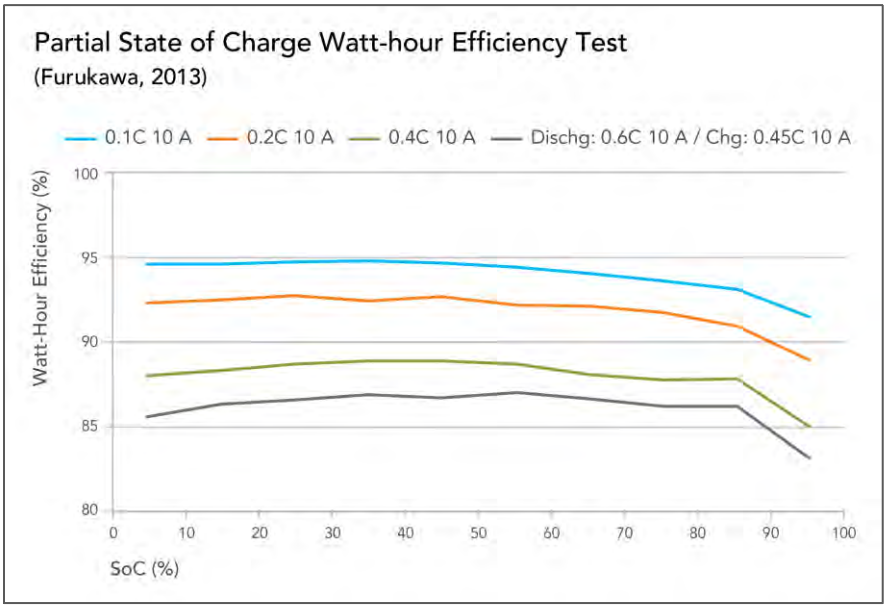

Figure 10: Results of efficiency testing undertaken at the Furukawa Battery Company (Furukawa, 2013)

Fuel efficiency is a measure of interest for HEV applications. For example, the Honda Insight HEV with an UltraBattery® pack, used for fleet duties, delivers an average of 44 mpg (5.3 L/100 km) in fuel economy when driven in mild temperatures and on reasonably flat terrain. This drops to approximately 35 mpg (6.7 L/100 km) when the temperature increases and the terrain become hillier (INL, 2012).

This measure does not relate directly to the electrical efficiency of the battery pack, because it is also affected by many additional factors including the battery capacity and its ability to accept regenerative braking power. An adequate compromise between vehicle acceleration and charging efficiency during regenerative braking is provided with an SoC window of 53–63%.

Operating at warm temperatures (30°C, or 86°F), the number of simulated vehicle miles covered before a simulated engine recharge is required is 142 miles (229 km) (INL, 2012).

4.5 Fewer Refresh Charges

Lead-acid batteries (like other battery technologies) periodically require a refresh charge, typically at a 1C rate, followed by a lengthy period of lower-rate charging at a ‘float’ voltage so that all cells reach 100% SoC. This helps to restore the physical state of the electrodes and allows the individual battery cells to attain consistent voltages and SoC, when otherwise they might diverge during an extended period of cycling. A refresh cycle concludes when the battery is returned to the SoC required by the application it is serving.

During a refresh cycle, therefore, the battery is not serving the application and so it is desirable to minimize this downtime. The UltraBattery® requires less frequent refresh cycles than a conventional VRLA battery, and this increases the time it spends on active duty.

Under PV hybrid cycling (Ferreira et al., 2012), which is a low-rate, high-energy schedule, the East Penn UltraBattery® after 40 days without a refresh charge showed performance far exceeding that of traditional VRLA batteries that had gone only seven days without a refresh charge, as shown in Figure 11.

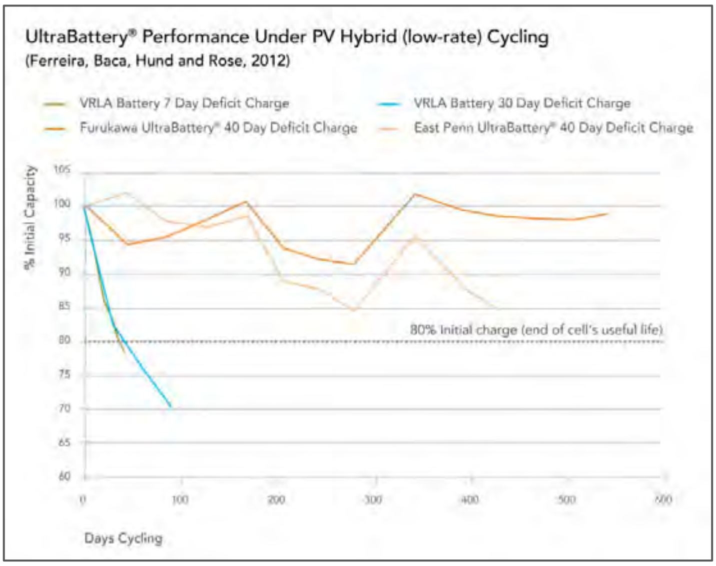

Figure 11: UltraBattery® performance under PV hybrid cycling (adapted from Ferreira et al., 2012)

One of the most impressive demonstrations of UltraBattery® longevity was during a test of a 144 V UltraBattery® module for HEV use, created by connecting 12 prototype Furukawa UltraBattery® cells in series. A life test was conducted of these modules in pSoC conditions simulating hybrid functions such as motor assistance at start-up and during acceleration, brake regeneration, and idle stop (Furukawa & CSIRO, 2008). The test was still underway even after 1,400,000 cycles had been achieved, with no refresh cycles at all. The capacity turnover of the UltraBattery® module exceeded 5000, which is an extraordinary value for a life test conducted on a lead-acid battery (or indeed on any battery) in pSoC conditions without recovery cycles.

UltraBattery® technology has also been tested with low rates of recovery charging in stationary applications. The cells consistently show capacity ratios equal to or exceeding 100% despite having been cycled many times and only receiving infrequent recovery cycles. For example, in a Furukawa Battery Company test under pSoC (Furukawa, 2013), a regime was devised whereby the cells were consistently cycled (charged and discharged) between 30% and 60%, with a recovery charge to float conditions being delivered only once per month. The cells tested were confirmed to have superior recovery charge characteristics compared with traditional VRLA batteries and, whereas the traditional VRLA cells declined steadily in capacity throughout testing (despite receiving recovery charges), the UltraBattery® cells *increased* in capacity from 100% and were above 103% capacity and still rising after several months of testing (the tests continued after the 2013 report was published).

Internal testing is continuing in order to determine the most efficient recovery charge interval for UltraBattery® technology to balance system uptime and cell longevity.

4.6 Less Downtime

This aspect of the value proposition is a consequence of requiring fewer refresh cycles. If refreshed for several hours once every 60 days, for example, the UltraBattery® can have downtime of less than 1% and thus be available for use more than 99% of the time. As discussed above, UltraBattery® cells have been shown in numerous tests to require very infrequent refresh charging (see, for example, Furukawa, 2013; and Ferreira et al., 2012).

4.7 High Charge Acceptance

When used in a pSoC regime performing variability management applications, such as regulation services or renewable ramp rate smoothing, UltraBattery® technology has exceptional charge acceptance capability. The actual charge acceptance rate is dependent on the particular UltraBattery® cell, but it is typically a multiple improvement on the charge acceptance capability of conventional VRLA batteries used in a typical top-of-charge cycling regime.

Charge acceptance depends on the voltage rise experienced during charging. If the voltage rises to the cell's or the pack's upper limit then no further charge can be accepted. During discharge no significant gap was observed between the UltraBattery® and a control battery (Furukawa, 2013). However, with respect to high-rate pSoC charging, the voltage of the UltraBattery® scarcely reached the charge terminal voltage, as shown in Figure 12, whereas the voltage of the conventional lead-acid battery frequently peaked to the charge terminal voltage. This indicates that the charge voltage of the UltraBattery® is very stable compared with traditional VRLA technology, signifying low internal impedance and good charge acceptance.

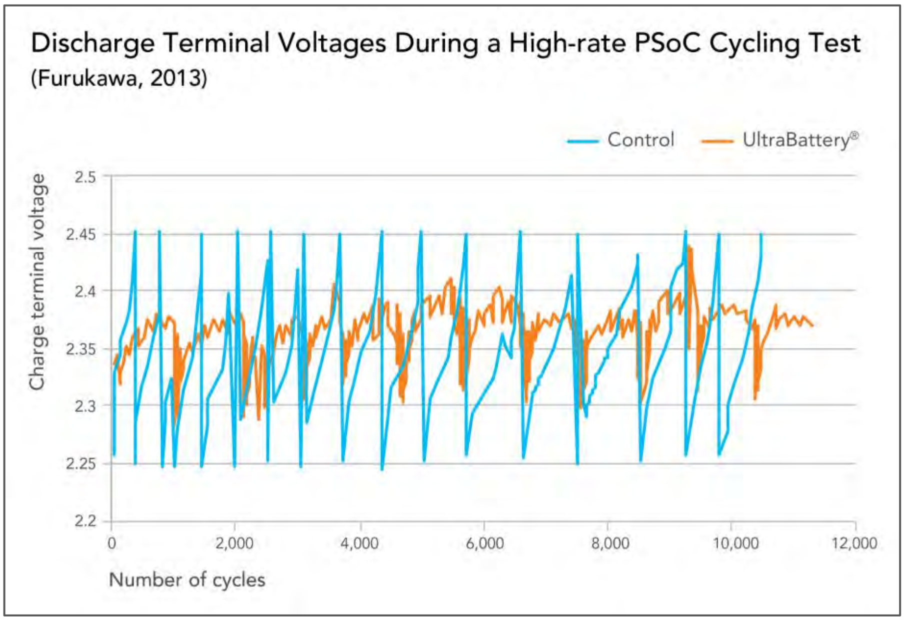

Figure 12: Discharge terminal voltages during a high-rate pSoC cycling test (Furukawa, 2013)

The sensitivity of charge and discharge voltages to rates was conducted on a Furukawa UltraBattery® at 50% SoC (Furukawa, 2013). Charge–discharge was conducted for 30 seconds at each rate and a break was given for 10 minutes after each charge–discharge.

4.8 Lower Variability of Cell Voltage Within Strings

Battery packs are made from 'strings' of individual cells connected in series so that their voltage sums to a high enough level for efficient power conversion. For example, a 144 V battery pack is typical for a medium HEV, whereas grid applications prefer voltages in the order of 500 V or more. Strings may be connected in parallel to increase the power capability of the battery pack.

During charging and discharging there is no control over individual battery cells in a series string, so their voltages and SoC may diverge over a period of cycling. This results in different rates of aging and some cells will fail earlier than they ideally would, disabling the whole string.

The presence of both the supercapacitor and battery chemistry in a single electrolyte in the UltraBattery® helps the cells in a string to equalize their voltages and SoC during extended periods of cycling. This was convincingly demonstrated when a direct comparison of the performance of four lead-acid battery technologies, including the UltraBattery®, was undertaken as part of a trial of renewable energy smoothing at Hampton Wind Farm in Australia (CSIRO, 2012).

The relative stability of cell voltages within a string is illustrated in Figure 13, which shows cell voltage variability in strings during a 10-month period of intensive operation. In numerical terms, over these 10 months the variability of UltraBattery® cell voltages (measured as the standard deviation of the graphed daily variation) increased by only 32%, while the variability of cell voltages of other lead-acid technologies increased between 140% and 251%.

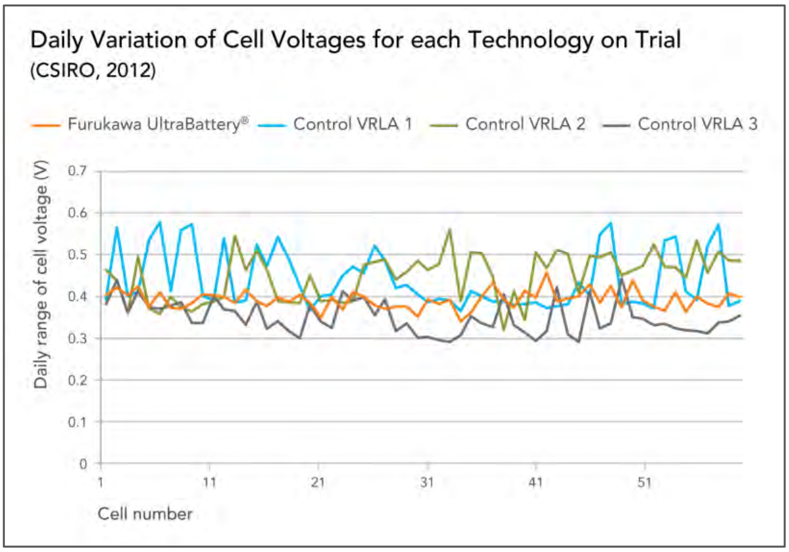

Figure 13: Comparison of daily variation of cell voltages over four lead-acid battery technologies after 10 months of operation at a wind farm, in which the UltraBattery® (thick blue line) shows much greater stability (CSIRO, 2012)

Cell voltage stability within a string was also demonstrated for an UltraBattery® module developed for HEV use (Furukawa & CSIRO, 2008; Furukawa et al., 2010). Figure 14 shows that the voltage deviations between individual batteries in a conventional VRLA string were rapidly enlarged during the initial 200,000 cycles, and this pack had to be removed from the test. On the other hand, it is clear that voltage deviations between the individual

UltraBattery® cells were small even after the UltraBattery® pack had undergone 1,400,000 cycles. The reason for the suppression of voltage deviations in the UltraBattery® string is hypothesized to be the greater charge acceptance of the capacitor components in these batteries, although this is an area where research continues. Maximizing the suppression of voltage deviations is fundamental to longevity and hence to low lifetime costs.

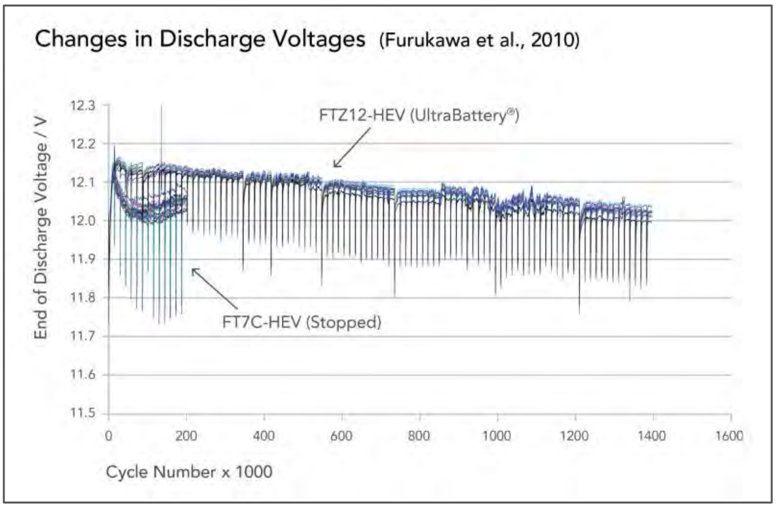

Figure 14: Changes in discharge voltages in individual batteries in 144 V strings of conventional VRLA and UltraBattery® cells under simulated medium-HEV cycling (Furukawa et al., 2010)

Observations of a Honda Civic HEV retrofitted with an UltraBattery® pack and subjected to fleet usage also demonstrated cell voltage stability (ALABC, 2013). After reaching 50,000 miles, the battery pack of this car showed no performance degradation and the individual battery voltages of the pack actually converged as they aged. This indicates not only that long lifetimes are possible, but also that UltraBattery® technology may operate with a battery monitoring system considerably lower in both complexity and expense than the systems required by other battery technologies.

4.9 Safety

Lead-acid batteries have been used for well over a century, and this familiarity has created a good understanding of safe practices. The UltraBattery® cell has the same safety requirements and benefits as any lead-acid battery. Its electrodes and electrolyte are non-flammable and have fire-retarding tendencies.

UltraBattery® technology is generally of the VRLA or 'non-spillable' design, which has achieved certification by IATA and DOT as being non-hazardous for transportation. Such is the safety record of VRLA batteries that, according to UN2800 *Batteries, wet, non-spillable, electric storage*, unless in a damaged condition, they are not subject to the US Hazardous Materials Regulations, meaning that there are no restrictions on their shipment by air or other transportation channels.

The electrolyte (aqueous sulfuric acid) is well managed through the life cycle of lead-acid battery manufacturing, transport, use, and disposal. Most lead-acid manufacturing plants recycle all elements of lead-acid cells and batteries, including the electrolyte. UltraBattery® manufacturer East Penn Manufacturing approaches 100% recycling rates for lead-acid products processed at its own recycling plant at its manufacturing facility at Lyon Station, Pennsylvania.

Any battery should be ventilated so that hydrogen generated by overcharging is able to escape. Because lead-acid batteries are already widely used in stationary and vehicular applications, there are standard installation practices in place to ensure that these requirements are met. While lead is an environmental contaminant that must be regulated, it has generally been through exposure to paint products and to factory and vehicle exhaust fumes that adverse effects in humans and animals to lead have occurred.

The very high rates of recycling of lead-acid batteries prevents any significant release of lead into the environment from lead-acid battery production and use. While the lead-acid battery supply chain consumes more than 80% of the lead used in the USA, it is responsible for less than 1% of the country's lead emissions.

4.10 Recyclability

Lead-acid batteries of all kinds are virtually 100% recyclable, including the battery's plastic, steel, acid, and lead components. Lead-acid batteries have very high recycling rates around the world and are the most fully recycled product in many countries, including the USA. The US Environmental Protection Agency (EPA) states that in the USA, 96% of all lead-acid batteries are recycled, and that a typical lead-acid battery contains 60–80% recycled lead and plastic (epa.gov/osw/conserve/materials/battery.htm).

In Australia, the Australian Bureau of Statistics states that 60% of all lead used in Australia is recycled, and that 93% of all motor vehicle batteries are recycled (Louey, 2010).

The European Union document 'Questions and Answers on the Batteries Directive (2006/66/Ec)' states that the collection of industrial and automotive lead-acid batteries in the EU is close to 100%.

As the energy storage industry develops and fulfills multiple applications in the electricity sector, well-managed recycling programs can be anticipated, following the precedent of the motor industry: for lead-acid technology, recycling rates of essentially 100% are not unexpected.

UltraBattery® recycling rates are expected to be higher than the standard recovery rates for lead-acid batteries for two reasons. Firstly, the units are shipped and used in containerized groups to known locations, whereas car-starter batteries are distributed individually and their location is not tracked. Secondly, the license holders for UltraBattery® manufacturing have strong existing recycling records.

For instance, UltraBattery® manufacturer East Penn Manufacturing has developed one of the world's most advanced lead-acid battery recycling facilities, which processes approximately 30,000 used lead-acid batteries per day. East Penn documentation (www.ultrabattery.com/recycling) describes the various stages in recovery, beginning with the batteries being collected, dismantled and separated. The lead is then smelted, then refined. Sulfur fumes created during the lead smelting process are trapped and processed into a liquid fertilizer solution. The plastic jars, cases and covers are cleaned and ground into polypropylene pellets that are then molded into new cases and parts at the company's onsite injection molding facility. East Penn recycles more than 11.8 million pounds (5.4 million kilograms) of plastic per year. Finally, the company's acid reclamation plant recycles approximately 6 million gallons (23 million liters) of acid per year.

The motivations for recycling are both environmental and economic. Production of secondary lead uses approximately one-third of the energy required to produce lead from lead ore, so recycling provides large financial and energy savings as well as reducing requirements for mining and smelting.

4.11 Separate Low-Rate and High-Rate Energy Capacities

Peukert's law explains how the capacity of a lead-acid battery changes according to the rate at which it is discharged. Typically, when lead-acid batteries are discharged quickly, only a small portion of the total available stored energy can be accessed. Fast discharging affects the reacting chemicals, which are at the interface between the electrodes and the electrolyte, and uses only the surface of the plate. Slower discharging allows for the diffusion of the reaction deeper into the plates, using more of the available active material.

By careful sizing of the lead-acid cell and its parallel-connected supercapacitor, one application can be low-rate in relative terms, drawing on the deeper active material in the plates, while the other can be high-rate, operating only at the surface of the plates. Applied this way, UltraBattery® technology may serve multiple applications simultaneously and almost independently (Wood, 2013).

5 Proposed Applications of UltraBattery® Technology

The flexibility of energy storage, particularly with respect to responsive battery technology and advanced power electronics, has excited the power and automotive industries because of the range of benefits that may be obtained through various applications (EPRI, 2010; Marchment Hill Consulting, 2012). Some of these have already reached commercial maturity, while others are visionary transformations of the industry.

This section describes the range of applications foreseen, and in many cases presently served, by UltraBattery® technology. The applications are linked with the required battery performance parameters, within the value proposition, which may be cross-referenced to the supporting tests.

5.1 Frequency Regulation

The fundamental task of an electric power system is to maintain the balance between electricity supply and demand at all times. This balance is exhibited in the system frequency, which is kept within quite tight limits around either 50 Hz or 60 Hz. The frequency is used as a control signal to maintain stable operation: if load increases or generation decreases, the frequency will fall until additional controllable generation compensates for the change.

Conversely, a decrease in load will allow an increase in speed of the generators that are spinning synchronously with the grid frequency, causing the frequency to rise. A number of generators are therefore assigned the role of 'frequency regulation', receiving a control signal from the power system operator to increase or decrease their output so that the supply–demand balance and frequency are maintained.

In North America the power grid is divided into four main interconnectors (the Eastern, Western, Texas, and Quebec Interconnectors), and frequency is maintained on each of these and also between each of these through a complicated system of instructions from more than 100 ‘balancing authorities’ who direct energy flows throughout the North American grid.

This distributed approach is contrasted with the centralized, but still market-driven, approach on the world’s (geographically) longest grid: the National Electricity Market covering all the eastern states of Australia. On this grid the normal ‘dispatch’ of generators happens every five minutes according to a complex optimization algorithm generated by a central agency, the Australian Energy Market Operator (AEMO). The calculation minimizes cost according to bids from generation companies subject to the capacity of the transmission network between regions of generation and of demand. Remaining differences between supply and demand are corrected by frequency control ancillary services (FCAS).

Whatever control system is used, the goal is always to maintain the voltage and frequency of the grid at its rated levels. The difficulty for generators providing frequency regulation or FCAS is that this inhibits their ability to generate at full rated output and earn energy revenue. Also, the rapid response that is sometimes required is beyond the capability of some generators, depending on their ‘ramp rate’.

For example, many large coal-fired generators are most efficient when producing a steady output, and gas turbine and hydro generators are better suited to frequency regulation, although significant wear-and tear is caused by rapid ramping to follow the regulation control signal.

UltraBattery® technology is ideally suited to provide these frequency regulation services to the grid. It is suitable for pSoC operation which allows it to respond in both directions, by charging, discharging, or changing the rate of charging or discharging. It responds rapidly and can ramp much faster than any conventional generator, following the regulation control signal accurately, and providing a better service to the system operator. The public-domain test data that support this application are published in Ferreira et al. (2012) and Hund et al., 2008, and include test cycles representing regulation services.

An example of UltraBattery® technology performing grid-scale frequency regulation is Ecoult’s 3 MW installation within the Pennsylvania-New Jersey Interconnection (PJM) grid.

5.2 Smoothing and Ramp-Rate Control

Globally, the renewable energy industry has recognized grid integration as one of the key constraints on the continued growth of wind and solar PV energy as major players in the power industry. The problems lie both in the electrical characteristics of the wind and solar PV generators and in the intermittency of their energy production.

While it is possible to introduce technical measures to ensure that generators comply with network requirements, it is more difficult to deal with the inherent variability in the energy generation. This variability covers a broad range of time scales from seconds through hours to days and months. Interconnected energy systems, like those existing in the USA and in the eastern states of Australia, manage variability using a variety of measures including normal dispatch practices, maintaining appropriate reserve capacity, renewable energy forecasting, frequency control ancillary services, and ramp-rate control.

On the Australian grid, AEMO has identified that the short-term (within one hour) variability in power-line flow can be quite substantial under some conditions where sizable wind generating facilities are present. This creates significant problems of voltage support and frequency control, as well as causing excessive peaking on transmission lines, thus reducing carrying capacity and increasing demand for high ramp-rate backup systems. This is particularly important where substantial renewable generation is present at the extremities of the grid or on relatively small capacity power lines, as is often the case for wind generation from high-quality resources that may be far from centers of demand. Ramp-rate control addresses short-term variability by controlling the rate of change of power output from a generator.

The integration of energy storage systems (at the point of generation or elsewhere on the transmission line) is an excellent method of ramp-rate management, because only a small energy storage capacity is required compared to the energy generated. Ramp-rate control is equally applicable to large-scale and small-scale renewable generation systems. Notably, one distribution utility in Australia has mandated energy storage for ramp-rate control of small-scale PV generators,

Standard lead-acid battery technology is unable to cope with the extreme cycling demands of ramp-rate control while delivering sufficient lifetimes. The UltraBattery® cell, in contrast, offers a much longer lifetime at high-rate pSoC operation while retaining the other advantages of lead-acid batteries including inexpensive construction and a high degree of recyclability.

Cycle profiles representing renewable energy smoothing applications for UltraBattery® cells are included in the public-domain test data reported in CSIRO (2012), Ferreira et al. (2012), Furukawa (2013), and Hund et al. (2008), as indicated in the Application Matrix on page 13.

Significant real-world data has now also been collected from a field installation in New Mexico. The Public Service Company of New Mexico (PNM) demonstration project installed an energy storage system into the grid comprising two elements: a 0.5 MW smoothing battery using UltraBattery® technology and a 0.25 MW/0.99 MWh peak shifting battery using advanced lead-acid batteries. The system was designed by Ecoult and both cell types were manufactured by East Penn Manufacturing (EPRI, 2012).

The project shows how energy shifting and smoothing on the grid can alter the profile of grid-scale renewables. UltraBattery® smoothing was applied to the output of a 500 kW solar PV array, where tests had measured ramp rates of 136 kW per second as solar energy was lost to cloud cover. Such large fluctuations in energy output become unsustainable as renewable penetration increases.

UltraBattery® technology has been shown to provide a viable and scalable solution. The provision by UltraBattery® cells of simultaneous shifting and smoothing (first shown to be viable during laboratory testing) has been very successfully demonstrated in this ongoing real-world project.

5.3 Power Quality

Electric power provided to customers should fulfill a range of power quality requirements for the benefit of both customers and the distribution networks that deliver the power. Keeping the voltage within the correct range is a primary safety requirement.

Other important elements of power quality include:

+ Harmonic content and phase balance, which govern the shape of the AC waveform
+ Power factor, which measures the relationship between voltage and current waveforms
+ Voltage sag duration and depth, which govern the permissible sub-second 'brownouts'
+ Interruption statistics, which measure the frequency and duration of the unavailability of power during each year.

Power quality is crucial to customers, particularly as appliances become increasingly sophisticated, and it is also critical for achieving safe and efficient transmission of power on distribution networks.

Customer needs have been changing due to the range of electronic appliances now found in typical residential and commercial buildings. Previously dominated by light bulbs, heating elements, and motors, customer appliances now include a variety of entertainment systems, computers, digital and plasma televisions, inverter-controlled air conditioners, and chargers for various personal electronic devices.

These new appliance types create customer demands for power quality that are often incompatible with the network code that specifies the performance requirements for distribution networks. Customers are also installing local generation systems, most notably rooftop solar PV panels, which further challenges the traditional role of distribution networks as deliverers of power from large-scale generation. Injecting power at points along the network, where solar PV systems are connected, dramatically changes the way voltage and protection (safety) should be managed by the network operator.

Battery energy storage systems are very good for managing power quality. Being connected to the grid via a power conversion system, they have the potential to manipulate the AC waveform in sophisticated ways that improve power quality measures, and the battery can provide real or reactive power to maintain voltage correctly. These functions can be performed for the customer, avoiding brownouts and blackouts, and to help manage the network.

Although any battery system can perform power quality functions in principle, such functions generally require the battery to be continuously in use, even at a low power level. UltraBattery® technology is particularly suited to this because it can sustain continuous operation at pSoC. Power quality functions can be performed by dual-purpose UltraBattery® systems that are primarily installed with another purpose in mind, which might be industrial/residential energy management or network peak shifting.

5.4 Spinning Reserve

Power systems have an inherent stability due to the inertia of powerful and heavy synchronous generators rotating at multiples of the grid frequency of 50 Hz or 60 Hz. The frequency is used as a control signal to maintain stable operation: if load increases or generation decreases, the frequency will fall until additional controllable generation compensates for the change.

Unexpected failures of generators or transmission lines will also cause the grid frequency to fall. Reserve generation capacity is managed over time scales from seconds to minutes to maintain the system frequency, and over hours to days to ensure that sufficient generation will always be available to meet load.

Reserve capacity for shorter time scales, which must be available when needed within minutes or even seconds, needs to be ‘spinning’ so that it is ready to ramp up rapidly. Any generator based on an engine consuming fuel will need some time to warm up from a cold start. Large, coal-fired generators typically require a day or more for a cold start, so their dispatch is carefully planned in advance, and if they are to provide reserve capacity they should be warmed up in advance and generating (spinning) at a low output level.

Gas turbines and gas or diesel reciprocating engines are more agile but still require a number of minutes for a cold start. Combined-cycle gas turbines are quite efficient, while open-cycle gas turbines are more agile but less efficient. It is unfortunately the case that quick-starting, agile generators are typically the least efficient generators, so that grid support services are often supplied using inefficient generation.

Moreover, while operating as spinning reserve, fuel-based generators will incur operating costs due to fuel consumption and wear and tear. Significantly, they also incur an opportunity cost of lost energy revenue while their output is held at level that is much lower than their nameplate capacity.

UltraBattery® technology is ideal for providing short-term ‘spinning’ reserve, because it can start instantly in either direction – charging (as a load) or discharging (as a generator) – without any warming up. It is able to sustain long periods of inactivity with a low rate of self-discharge and periods of continuously variable operation, depending on the system operator’s requirements, which in turn relate to the sources of variability in network load and generation.

UltraBattery® cells can also support longer-term spinning reserve by providing a fast-start capability to a fuel-based generator, providing instantaneous power and bridging the time taken for a cold start, after which the fuel-based generator would take over from the batteries. In effect, the UltraBattery® cell does the ‘spinning’ instead of the generator, with a consequent reduction in fuel consumption and wear and tear.

The Sandia National Laboratories have long understood the potential for batteries to serve multiple applications and have therefore developed compound cycle profiles for ‘stacked’ applications (Ferreira et al., 2012). By including periods of inactivity between periods of rapid response, these profiles effectively address the spinning reserve application, as marked in the Application Matrix on page 13. Data collected in real-world simultaneous smoothing and shifting (EPRI, 2012) also suggests that UltraBattery® technology is well suited to providing grid support services such as replacing fossil-based spinning reserve.

5.5 Residential Energy Management

Electricity is a significant household cost in both developed and developing economies. In nations with large, dispersed or remote populations increasing fuel costs, network investments, and other factors make interconnected networks expensive and difficult to maintain. In many regions – particularly remote locations and fast-growing urban areas in developing economies – energy security and reliability are significant concerns for households and businesses.

Residential electricity *production* is now quite normalized, and the electricity grid (designed to deliver energy from source to load) often now has to manage domestic loads that alternate between load and generator depending on the sun. This pattern requires grid operators to pay far more attention to demand management than was required under the traditional pattern of passive consumption, particularly as localized cloud cover could see available power drop with very steep ramp-rates in areas with high rooftop photovoltaic penetration.

The UltraBattery® presents an ideal technology for residential energy management services in such circumstances. It is designed for pSoC operation which allows it to charge or discharge at any time according to several application requirements, it is an effective energy-shifting battery for residential energy management according to tariff regimes and PV generation, and it has a high power capacity to offer network services in addition to residential services.

Ecoult is developing several modular systems designed for residential energy management, and a new testing program (Ferguson, 2013) has recently begun.

5.6 Energy Shifting and Demand Management

While many of the applications described here focus on flexible power import and export capabilities, the UltraBattery® is also an excellent energy-shifting device, and an installation can be sized so that energy-shifting requirements can be accommodated within a range of SoC and power capacity that ensure longevity.

High efficiency, measured on the AC side of the power conversion system, is required because loss of energy is undesirable in a shifting application while it may be tolerable in a high-power, low energy application. Public-domain test data using such profiles may be found in Ferreira et al., (2012), Furukawa, (2013), and Hund et al., (2008) as indicated in the Application Matrix on page 13.

Energy shifting is a part of the requirement for residential energy management and multipurpose use in datacenters and commercial buildings. These demand-side applications are complemented by several opportunities for energy storage to improve the safety and efficiency of electricity networks.

The electricity market and system operator together ensure that the totals of supply and demand are matched within the balancing region. As the transport mechanism, networks are responsible for linking points of supply and demand and managing local peaks and troughs and differences that may occur on a smaller scale. The network can always be built with enough capacity to do this, but there is an important question of investment efficiency, and networks are very expensive investments, typically accounting for as much as half of the cost of electricity.

For example, in Western Australia the average load is approximaely half the maximum load, and the load exceeds 90% of the maximum load for less than 0.5% of the year. Other global regions report similar figures, showing that the last 10–20% of network capacity is grossly underused and therefore represents an inefficient investment. Energy-shifting capability is an alternative investment that can reduce peak demands by spreading the same energy consumption over a longer period.

Peak demand management by energy shifting can happen in a variety of circumstances on the network. Growth of peak demand has been a longstanding phenomenon globally, particularly due to increasing use of air conditioning, increasing house sizes with an increasing range of appliances, and population growth. Typically a network element, such as a transmission line or a transformer, is marked for replacement according to regular reviews of network condition and capacity. However, this investment must always compete with many others and, due to the size of overall network investment, there are formal processes to consider alternatives that may be more efficient.

Energy storage for shifting consumption is an attractive alternative because it can also perform many other useful network functions, such as injecting real or reactive power as necessary to maintain voltage in the correct range for customers, helping customer loads to ride through network faults, and in some cases allowing islanded operation sustained by local renewable energy generation. Each of these functions can improve the level of service and remove the need for additional equipment.

Most distribution networks use three-phase components and transmission lines and carry multi-MW of load. They require substantial energy storage facilities to allow a useful level of demand management. Opportunities for small-scale storage can also be found, though, in the many single-wire earth-return (SWER) networks that serve smaller communities in rural areas. These networks are often operated close to load limits, with aging infrastructure, and long line lengths per customer. Frequently they pass through sensitive landscapes including fire-prone and difficult-to-access areas, and this can create a good case for removing the SWER line and installing a remote-area power supply (RAPS) (another application for energy storage, discussed below).

Alternatively, energy storage can help to extend the network's lifetime and defer a major investment in either in feeder upgrade or a RAPS that would allow the feeder to be decommissioned.

5.7 Diesel Efficiencies

Geographical constraints often prevent interconnection between power systems, and RAPS are installed to provide electricity to islands and remote communities. These are alternatively known as microgrids and are generally either fossil-fuel powered or, increasingly, powered by a hybrid system employing renewables with a fossil fuel backup. The economic case for using renewable generation to reduce fuel costs in remote power systems is strong in many such situations, particularly as diesel fuel costs increase. Energy storage provides the mechanism by which this can be achieved while maintaining or improving the reliability of the power supply.

Smaller communities and individual homes or farms can use ‘standalone’ RAPS in which the diesel genset is relegated to providing backup power. The renewable energy generator provides most of the energy required by the load, and charges an energy storage system that has a large capacity compared to the daily energy consumption. A diesel genset is used as a backup when there has been insufficient renewable energy for some time or when the load is particularly high due to an unusual activity, such as arc welding. Fuel efficiency is achieved due to the diesel genset being able to remain off for most of the time.

Larger communities require ‘hybrid RAPS’, in which one or more diesel gensets are usually operating and supplementing the renewable energy generator. The energy storage system helps to balance this total supply against the load demand; this requires a relatively small energy capacity.

Energy storage is used to absorb rapid changes in both renewable energy output and system demand, so the diesel gensets are exposed only to a slowly changing operating regime. With storage in place the diesel genset does not need to operate at low load (that is, as spinning reserve), since the storage can cover moments when the renewable energy output drops suddenly. Fuel consumption of a diesel engine increases considerably the further below its rated capacity it is required to perform, and efficiency is approximately 23% less when operating at 25% of the rated load than it is operating at rated load. This is an important factor in deciding the desirable minimum loading of the diesel genset.

Another crucial factor is that sustained operation under light-load conditions significantly increases the risk of engine failure, and can cause premature aging of the diesel genset. Operation at light load also reduces the response time of the genset. Thus, diesel gensets are normally set to operate toward the rated load and, at the lowest, in the range of 30–50% of rated load.

Using energy storage, therefore, directly improves diesel operating efficiency because higher loadings can be achieved for longer periods, and also improves diesel engine longevity. The UltraBattery® has good responsiveness and efficiency at pSoC, which makes it an excellent technology for balancing hybrid RAPS, in the same way as it can provide spinning reserve for interconnected power systems. The UltraBattery® cell is also a highly capable deep-discharge energy store for standalone RAPS in which it might be required to supply the load for prolonged periods.

5.8 Multipurpose use in Datacenters and Commercial Buildings

Datacenters are very large electricity users and they typically have an existing energy storage resource in the form of a battery backup system. These storage systems are already grid-connected and present an opportunity to provide services to the grid including regulation services and demand management, as discussed in previous sections, provided that the batteries are capable of delivering these services in addition to backup power. Traditional lead-acid batteries cannot sustain continuous charging and discharging operations without dramatically shortening their lifetime: rather, they are designed to sit on ‘float current’ fully charged and waiting for a UPS event. UltraBattery® storage units are fully compatible with traditional UPS batteries in a datacenter, and they can operate in continuous charge and discharge to provide grid services.

The provision of grid ancillary services offers a new source of revenue for what is today a 'cost only' investment for datacenter operators. The widespread presence of backup energy in datacenters today presents a substantial buffer for the grid, and an enormously valuable, already existing resource that can be unlocked to support variability management and accelerated renewable integration.

Moreover, carbon dioxide savings extracted from using energy storage instead of fossil fuelled generators for frequency regulations may count toward a datacenter's contribution to carbon dioxide savings in markets with carbon pricing mechanisms. Additionally, this model offers a very compelling advantage of economic returns: revenues from the provision of frequency regulation services in parts of the USA exceed the marginal cost of investment from using a slightly bigger store of UltraBattery® cells to fully support the dual purposing of a datacenter.

Datacenters are an example of a wider variety of commercial buildings that could find multipurpose UltraBattery® energy storage an attractive facility. As well as providing a UPS and ancillary services to the grid, UltraBattery® systems can help manage energy flows within a building, which may include peak demand reduction to reduce capacity charges, consumption or market dispatch of locally generated energy from rooftop PV arrays, and energy shifting to minimize energy costs according to a fixed or variable tariff regime.

This multipurpose application is a combination of demand management and frequency regulation and, as such, the same public-domain test data may be taken to support it (Ferreira et al., 2012; Furukawa, 2013; and Hund et al., 2008).

5.9 Micro- and Medium HEVs

In part due to tighter regulation of vehicle emissions, HEVs are now a mainstream alternative to vehicles powered only by an internal combustion engine, with most major car manufacturers offering a range of HEV options in parallel to their traditional range, including some commercial vehicles. Micro-, medium, and full HEVs are varieties with different requirements with respect to battery size and capability, and all may be well served by the UltraBattery®.

Micro-HEVs have an 'idling-stop' function that stops the internal combustion engine when the vehicle stops. They also use regenerative braking to recover some of the vehicle's energy of motion to help charge the battery. With these innovations the fuel efficiency is typically increased by approximately 10% compared to a non-hybrid vehicle. Micro-HEVs do not provide electric drive to the wheels of the car. They use a single 12 V battery in a similar format to a traditional car battery; however, the demands on the battery are significantly different.

In micro-HEVs, power is not available from the alternator when the engine stops idling, so electrical appliances such as lights, audio systems, and air conditioning must be powered from batteries, resulting in a deeper discharge. To accept charge from regenerative braking efficiently, the battery is kept at pSoC, typically about 90% full, and it must be able to withstand high charging rates.

This contrasts with non-hybrid vehicles, in which the battery floats on full charge using the alternator to provide mild charging rates. Micro-HEVs usually need to restart the engine when the driver releases the brake pedal after stopping, so the number of large-current discharges increases compared to non-hybrid vehicles. (Some micro-HEVs use combustion to restart the engine by sensing the cylinder positions.) These factors mean that a normal car battery would have a very short lifetime, so special battery technologies are required.

Medium (or mild) HEVs provide electric propulsion. They use idling-stop and regenerative braking, as do micro-HEVs, with the additional requirement of acceleration. This moderates the power demands on the internal combustion engine and typically increases the fuel efficiency by approximately 20–25% compared to a non-hybrid vehicle. They include the same innovations as a micro-HEV and the electric motor, alternator and battery are larger and play a greater role in the operation of the vehicle. For greater efficiency for sustained high-power discharge during acceleration, 144 V battery packs are used rather than single sealed or flooded units.

A full HEV is similar to a medium HEV except that the electrical components are much larger in size, and able to propel the vehicle under electric power alone, while the internal combustion engine is consequently smaller. Usually the battery pack voltage will exceed 200 V. A more sophisticated control system is needed to optimize efficiency under a range of operating conditions, increasing the fuel efficiency by approximately 40–45% compared to a non-hybrid vehicle in an urban setting.

All the advantages of HEVs apply to commercial vehicles as well as private cars, and there are additional factors that make them particularly attractive.

+ Commercial vehicle fleets are centrally managed from purchase to disposal, so there is a well-informed framework within which to evaluate the economic and environmental benefits of switching to HEVs.
+ Commercial vehicles tend to have a constant pattern of use, which also helps to quantify the benefits of switching to HEVs, and may support the introduction of fully electric vehicles – there is no need to allow for an occasional long-distance journey that may exceed the range provided by the battery pack.
+ The pattern of use typically includes regular intervals at a depot or way station, where charging may occur.
+ Finally, most commercial fleet vehicles operate in urban environments with frequent stopping and starting and a heightened sensitivity to vehicle emissions and noise.

For all of these reasons, the benefits of HEVs and fully electric vehicles are likely to be maximized in the case of commercial vehicles.

Several public-domain UltraBattery® test programs have targeted HEV applications; these are indicated in the Application Matrix on page 13.

5.10 Railways

Electric power is widely used in railways, and battery energy storage can be used to provide hybrid power with similar benefits to those obtained for road vehicles. The transition to hybrid power should be easier because many trains already have both diesel and electric motors. In Europe, for example, just over half of the train tracks are electrified, and some trains are designed to operate with diesel or electric drive. Energy storage can also provide important support to the stationary electricity infrastructure that supplies overhead or third-rail power to trains.

Hybrid power technology has so far been limited mostly to shunting locomotives, which have particularly high energy losses due to continuous start–stop operation. Long investment planning cycles, an intense focus on reliability, and the more extreme conditions faced by trains have inhibited change. Nevertheless, the first hybrid passenger trains are now starting to appear on routes with frequent stops that have many opportunities to recharge batteries using regenerated braking power.

There are several advantages to this beyond efficiency. Hybrid power allows emissions-free train movements in sensitive or populated areas, particularly around stations where acceleration occurs. Trains have a lower power-to-weight ratio than road vehicles so they are less sensitive to the additional weight of a battery system. Railway rolling stock is also built to last a long time, so it can make good economic sense to retrofit a hybrid power system to an existing locomotive or passenger set, rather than waiting to order replacement rolling stock.

Electric railways require an electricity distribution network that operates in parallel with the grid that supplies the rest of the community, having only high-voltage substations in common. The two grids cannot be too closely tied due to the detrimental effects that passing trains may have on the quality of power delivered to urban or rural electricity customers. Particularly near railway stations and on inclines, the load is characterized by peak demands of great intensity separated by significant periods of low load.

As for the general power grid, supplying very ‘peaky’ loads requires a strong but underutilized network, which tends to be a highly inefficient investment. Stationary energy storage at strategic points along the railway can supply peak demands of passing trains while being charged in a more continuous fashion by a lighter, and much cheaper, electricity distribution network. This application requires a good energy-shifting battery that has high power output capability.

The application of battery energy storage to railways is sufficiently different from other HEV (motive) and network support (stationary) applications that there are no public-domain test data presently available to demonstrate the effectiveness of UltraBattery® technology in this role. However, extrapolating from existing results, it is very unlikely that UltraBattery® technology would not be suitable for application to energy storage along rail corridors.

6 Conclusion and Further Research Opportunities

A wide range of tests has demonstrated that the UltraBattery® is a highly capable and long-lasting multipurpose energy storage technology. These tests have been performed by government laboratories and through collaborations between several organizations. Much of the data is available in the public domain. This White Paper has assembled some of the significant publicly available test data in support of the key benefits of the UltraBattery® technology: in particular, long life, high efficiency, few refresh cycles, high charge acceptance, and cell voltage stability.

The market segments where these key benefits are important have been described through 10 areas of application. They include grid and automotive applications, some of them mature and already attracting energy storage solutions, others emerging and ready for commercial demonstration using capable technologies. These applications are also linked to the test data, and the UltraBattery® is shown to be well suited to them all.

This White Paper recommends that, while ongoing test regimes will continue to provide deeper understanding of the technology, newly available field results from commercial operations should now begin to be aggregated to allow a more nuanced understanding of how UltraBattery® technology performs in a wide range of operational conditions. As large amounts of data become available from kW and MW scale implementations, the technology's performance parameters can be understood under various environmental conditions and charge–discharge regimes, and this will likely expand the range of potential applications available to this important and valuable storage technology.

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Case Study

PJM Interconnection (PA, US)

Regulation Services

Background

Ecoult implemented an energy storage system which provides 3MW of regulation services on the grid of PJM Interconnection, the largest of 10 RTOs/ISOs in the US. The system is also used for peak demand management.

Customer Challenge

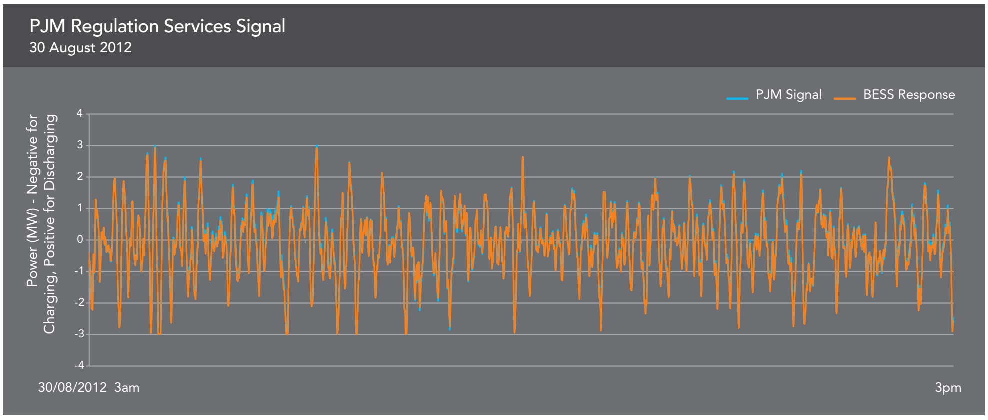
With renewable portfolio standards coming into effect, the large-scale integration of intermittent wind and solar generation will affect the physical operation of the modern grid, resulting in an increasing need for regulation services.

Regulation services are necessary to provide fine tuning in real time for the network to match supply and demand and thus keep a constant frequency. The energy store responds to a signal provided from the market operator, PJM.

The project objective is to demonstrate the outperformance of the UBer™ (UltraBattery® Energy Resource) in the provision of regulation services. The fast-responding UltraBattery® technology can manage regulation services more efficiently. It is faster, more accurate, cheaper, and cleaner than the incumbent gas peakers often used for regulation services. The UBer™ is therefore able to displace fossil fuel generation methods in the provision of regulation services and to complement fossil fuel generation in the provision of other ancillary services.

Solution Provided

The Ecoult 3MW UBer™ was implemented both in a building and in a containerized format to demonstrate flexibility in approach for prospective adopters. It uses four strings of UltraBattery® cells and connects to the grid from inside the East Penn Manufacturing site in Lyon Station, Pennsylvania.



The project provides continuous frequency regulation services bidding into the open market on PJM. The system is responding to PJM's fast response signal.

Case Study

PNM (NM, US)

Solar Smoothing and Shifting

Background

PNM, the leading electric utility company in New Mexico, US, has integrated an Ecoult UBer™ (UltraBattery® Energy Resource) with a solar energy-generating farm to demonstrate smoothing and shifting of volatile solar power and the ability to use the combination as a dispatchable renewable resource. The project is the first solar storage facility in the US that is fully integrated into a utility's power grid. It features one of the largest combinations of battery storage and photovoltaic energy in the US.

Customer Challenge

Increasing levels of renewable energy penetration poses integration challenges for grids. In the case of New Mexico, there were two particular objectives:

- To better manage the misalignment between PV output and utility distribution grid and system peaks
- To better manage intermittency and the volatile ramp rates of renewable energy sources that cause voltage fluctuations.

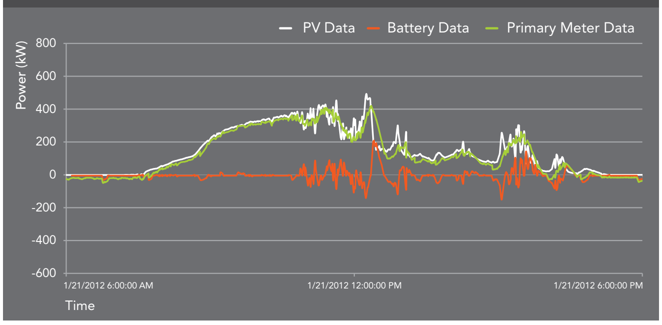
Ecoult worked closely with PNM, Sandia National Laboratories, the University of New Mexico and a number of other contractors to demonstrate:

- Peak shaving, targeting elimination of 15% of the feeder peak – benefit defined by avoided industry standard costs of substation and feeder expansion
- Smoothing of PV ramp rates and minimizing of voltage fluctuations – benefit defined by avoided cost of system upgrades that would be installed with high-penetration PV
- Demonstration of dispatchable renewable resource – benefit defined by contrasting the cost of an equivalently dispatched combustion turbine, allocating fuel, operation and maintenance, and capital to an LCOE (levelized cost of energy) comparison and noting an allowance for CO_2 emission avoidance.

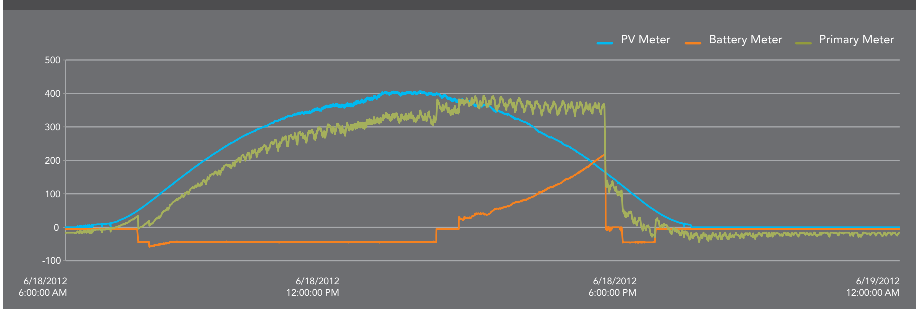
Solution Provided

The UBer™ provides 500KW of energy-smoothing capability (utilizing UltraBattery®) and 250kW/1MWh of energy-shifting capability (utilizing Deka Synergy®). The UBer™ is successfully smoothing and shifting PV output and demonstrating the ability to combine PV with a storage system, providing multiple benefits to making renewable resources reliable and dispatchable. Initial results indicate that targeted objectives are easily being met.

Smoothed Solar Output: UltraBattery® Solar Smoothing Functionality Proven
Public Service Company of New Mexico (PNM) Solar Smoothing and Shifting Project
Data Set from 21 January 2012



Shifted Solar Output
Public Service Company of New Mexico (PNM) Solar Smoothing and Shifting Project
Data Set from 18 – 19 June 2012



Case Study

Hampton Wind Farm (NSW, Australia)

Wind Smoothing

Background

Wind energy is clean and has the potential to supply many times the total current global energy production. Although wind energy is reasonably predictable, it is significantly variable. The ramp rate that can be associated with generation of wind energy can create integration challenges for utilities and ISOs/RTOs and limit progress by wind farm developers.

Customer Challenge

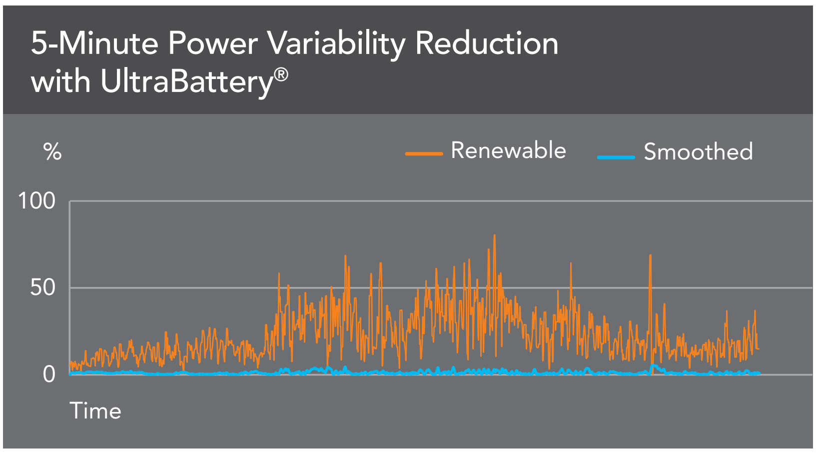
Wind power cannot be controlled. Wind farms exhibit greater uncertainty and variability in their output compared to conventional generation. In power systems, which already manage a large degree of uncertainty due to the need for generation and loads to be equal, demand is constantly matched with generation to maintain system frequency. The variability and uncertainty of wind power further increases uncertainty in the system, affecting its physical operations.

Further challenges with supporting increased penetration of intermittent resources are related to congestion issues in the transmission and distribution system as well as the mismatch between wind availability and prevailing demand. Often, local networks are constrained, with renewable energy being forced to be curtailed.

An immediate solution to wind integration challenges is to control the ramp rate of wind output. The project objective is to demonstrate and optimize methods of applying UltraBattery® storage to constrain the 5-minute ramp rate of renewable output from the Hampton Wind Farm before presenting it to the grid. The impact objective is to achieve higher penetration of wind and renewable energy in grid systems.

Solution Provided

Ecoult provided and integrated a MW scale smoothing system using UltraBattery® technology. Ecoult has been able to demonstrate the ability to limit the 5-minute ramp rate to 1/10 of the raw output while applying storage with a usable capacity (in kWhs) 1/10 the rated output of the farm (in kW).



Grid Storage Solutions

VERSATILE.
FLEXIBLE.
PROVEN.

A123 ENERGY SOLUTIONS

The Nanophosphate® Advantage

Today, A123 Energy Solutions is proud to feature industry leading Nanophosphate® lithium ion battery technology. Developed by A123 Systems, Nanophosphate delivers high power and energy density combined with excellent safety, performance and cycle life.

POWER:
Superior power by weight or volume in a cost effective solution

LIFE:
Excellent calendar and cycle life with consistent performance over extended use

SAFETY:
Nanophosphate® is stable chemically, providing the foundation for safe systems

ENERGY:
Higher usable energy means greater battery utilization and lower cost

VERSATILE.

Advanced energy storage technology is integral to increasing the efficiency of power grids worldwide by enabling them to become smarter, cleaner and more reliable. By efficiently decoupling generation from demand, A123's highly versatile megawatt scale Grid Storage Solution (GSS) helps traditional and renewable power plant, transmission and distribution asset owners meet these needs today. The GSS serves to smooth output and improve quality from renewable power facilities, lower emissions, maintenance and capital costs of traditional power plants and increase T&D utilization factors and effective capacity.

Grid Storage Solution Key Benefits:

A123's GSS facilitates multiple efficiency gains on the power grid providing a safe, reliable and fully-integrated system that enables customers to:

INCREASE SYSTEM EFFICIENCY

- Decouple generation and load
- Operate thermal assets at optimal output
- Reduce emissions
- Increase asset efficiency and utilization
- Reduce operating and maintenance costs
- Release "reserve capacity" into revenue generating service
- Ease transmission constraints

IMPROVE GRID STABILITY AND RELIABILITY

- Provide ancillary services
- Improve frequency regulation and balance load at a lower cost
- Provide new capacity that can be deployed quickly
- Provide dependable frequency response

ENABLE INTEGRATION OF RENEWABLE SOURCES

- Mitigate intermittency, "firming" of renewables
- Provide greater ramp rate control
- Supports Renewable Portfolio Standards (RPS) targets

INCREASE ENERGY SECURITY

- Support utilization of diverse domestic energy supply, including renewable sources

Grid Storage Solution Applications:

A123's GSS technology is highly versatile and provides a solution for multiple applications across power generation, transmission and distribution to increase efficiencies, improve power quality and support greater asset utilization.

GENERATION

- Frequency Regulation
- Renewable Integration
- Spinning Reserve
- Power Plant Hybridization
- Ramp Rate Management

TRANSMISSION

- Voltage Support
- Dynamic Line Rating Support
- Renewable Integration
- Dynamic Stability Support
- Loss Reduction
- Constraint Relief

DISTRIBUTION

- Residential and Industrial Backup Power
- Microgrid and Island Grid Support
- Distribution Upgrade Support
- Peak Load Reduction

FLEXIBLE.

A123's Grid Storage Solution (GSS) is a flexible and fully integrated turnkey solution with a grid-ready design that can be rapidly deployed today to enable generators, utilities and both traditional and micro grid operators reduce costs and increase plant efficiency. With High-Rate (HR) and Long-Duration (LD) options ranging from kilowatt-scale to 500 or more megawatts, A123's GSS can be easily configured to meet customers' exact power and energy requirements. The modular design of the GSS system is highly portable, easy to site and permit and can be configured to fit in spaces that cannot accommodate traditional generation assets.

Grid Storage Solution Architecture

A123's GSS offers a flexible, modular architecture that consists of three key components: the Grid Battery System (GBS), AEROS™ Energy Control System and Power Conversion System, which are fully integrated and grid-ready. The GSS delivers a system-level AC-AC roundtrip efficiency rating of 90 percent*.

*90% efficiency rating at system level, based on AC-DC-AC conversion, including battery management system electronics, excluding auxiliary power.

Grid Battery System

A123 Energy Solutions' Grid Battery System (GBS) is based on modular energy storage units, which serve as the building blocks for easily configurable HR and LD energy storage systems that meet application-specific requirements. The standard containerized GBS includes the 20', 40' and 53' LD systems and the 53' HR system. Fully functional, free standing GBS Zone subsystems are also available can be housed in building enclosures. All GBS units come as part of a GSS solution including zone level touch screen control interfaces, and an integrated fire prevention, detection and suppression system.

AEROS™ Energy Control System

AEROS™, the A123 Energy Response Operating System platform, delivers full industry leading command and control functionality for seamless integration with utility systems. Features of AEROS™ include:

- Automated command and control via industry-standard secure protocols
- Manual control remotely via secure Web-based user interface
- Multi-user access with customizable access rights
- Real-time reporting of system capabilities and performance
- Multiple applications available including frequency regulation, frequency response, renewables (wind and solar) ramp management, load leveling, volt/VAR support, and more
- Optional fast-response droop support for voltage and frequency
- Dynamic mode selection based upon customer-defined rules
- 250 millisecond standard response time, <30 millisecond high speed option available
- Communications protocol support including DNP3.0, IEC61850, Modbus TCP, SNMP, and IEEE C37.118
- Clustered configurations available for high-availability on all GBS units
- Remote monitoring, data collection and data historian options with GPS-time synchronized timestamping
- Integration with optional IP video surveillance system
- High- and low- frequency ride through
- Optional redundant control architecture for enhanced failover protection

Power Conversion System

A123's GSS features integrated high–efficiency bidirectional power converters that inject and absorb real and reactive power between the GBS and grid. Features include:

- Fully containerized modular solution with various enclosure options
- Four-quadrant capable
- IEEE 1547 compliant, IEEE 519 compliant options
- High- and low-voltage and frequency ridethrough
- 50Hz or 60Hz connection frequency options
- Optional step up transformer to MV AC output
- 480VAC output (typical)

PROVEN.

With more than 100 megawatts shipped to date, A123 Energy Solutions is the world's leading supplier of advanced battery systems for grid energy storage. Our global utility and independent power producer customers include AES Energy Storage, Sempra Generation, Southern California Edison, Dongfang Electric Corp., Vestas, Maui Electric and Northern Powergrid, among others. These and other customers are deploying A123's GSS for a number of applications, including frequency regulation, spinning reserve, renewable integration and substation storage.

Learn more at www.a123systems.com

VERSATILE.

Grid Battery System Standard Containerized Unit Details




	Long-Duration (LD) Grid Battery Systems			High-Rate (HR) Grid Battery System
Model Number**	GBS-C53-LD40	GBS-C40-LD28	GBS-C20-LD12	GBS-C53-HR20
Energy Storage	4 MWh (nominal at C/2 rate)	2.8 MWh (nominal at C/2 rate)	1.2 MWh (nominal at C/2 rate)	575kWh (nominal at 4C rate)
Power Rating	4 MW	2.8 MW	1.2 MW	2 MW
Dimensions (LxWxH)	53' x 8.5' x 9.5' (16.2m x 2.6m x 2.9m)	40' x 8.5' x 9.5' (12.2m x 2.6m x 2.9m)	20' x 8.5' x 9.5' (6.1m x 2.6m x 2.9m)	53' x 8.5' x 9.5' (16.2m x 2.6m x 2.9m)
Mass	141,000 lbs	103,000 lbs	49,000 lbs	64,000 lbs
DC Efficiency*	97% (C/2 rate)			96% (1C rate)
DC Voltage	944V nominal (750V – 1050V DC operating range)			960V nominal (750V – 1050V DC operating range)
Ambient Operating Temperature Range	-30˚C to + 50˚C			
Enclosure details	Containerized, ISO 1496-1 certified, IMO CSC-compliant, designed to IP56 per IEC60529			

* Inclusive of battery management electronics; excluding auxiliary power consumption by thermal management systems. Long-Duration GBS efficiency measured at full depth of discharge. High-Rate GBS efficiency measured at partial depth of discharge near mid state-of-charge.

** Models shown represent the maximum number of racks per container. Rack count may be reduced to modify capacity and power.

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MD100120

Premium Power

TRANS-FLOW 2000

ENERGY STORAGE SYSTEM

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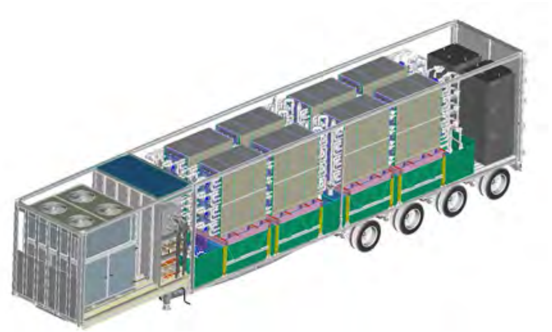
Tel: 978.664.5000
www.premiumpower.com

Section 1: System Overview

Premium Power Corporation's TransFlow 2000 delivers the most flexible and easy to install, fully integrated, large-scale energy storage solution that meets the needs for:

- Power distributors:
    - Load support at heavily loaded substations during periods of peak demand
    - Load support on distribution lines that are experiencing significant growth in demand
    - An energy storage asset with the ability to be relocated simply and quickly without complex disassembly and reassembly
- Renewable energy generators:
    - To time-shift energy generated so as to deliver it during periods of peak system demand

The TransFlow 2000 is a fully integrated system that comprises energy storage, power conditioning, system control and thermal management subsystems into a packaged, portable, turn-key, building block to be placed wherever it is needed for immediately dispatchable on-line energy storage.

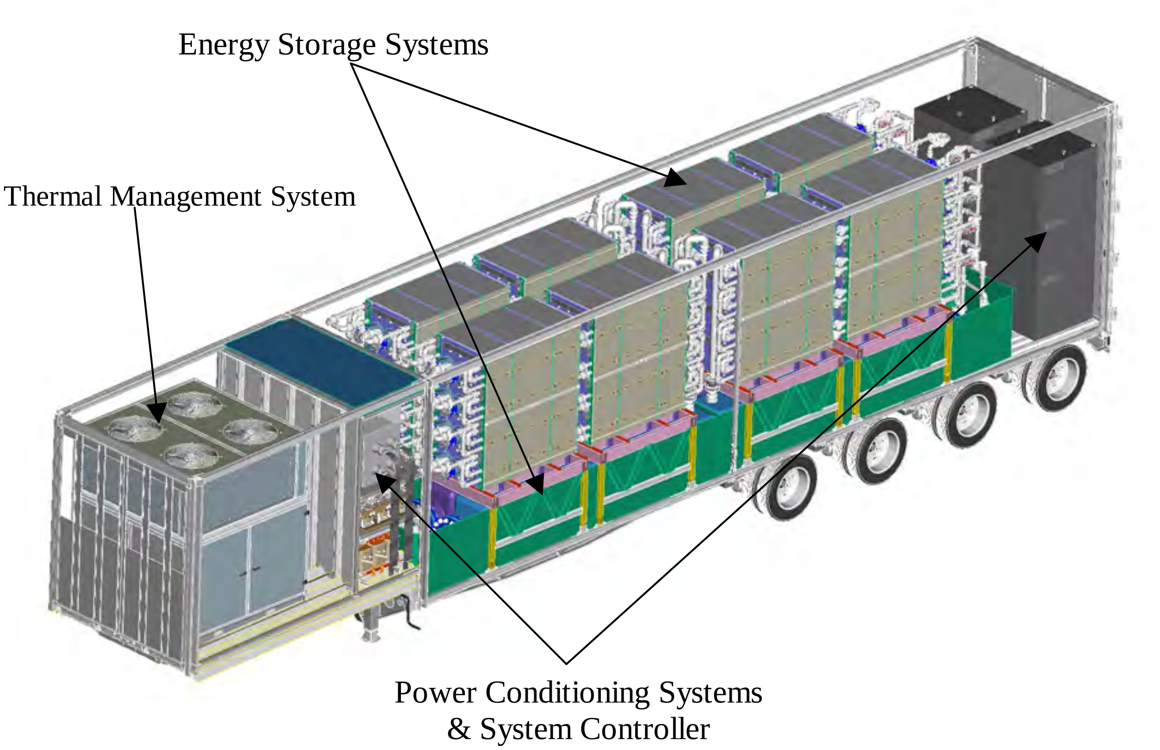


Each TransFlow 2000 system:

- Is packaged onto a tractor-trailer that can remain a mobile asset capable of being hauled to any site.
- Optionally, it may be off loaded as a freight container if desired.
- Is configured to allow multiple units to be automatically paralleled for higher power or greater energy storage requirements.

The overall system comprises four main subsystems – each subsystem is described in more detail in the following Sections:

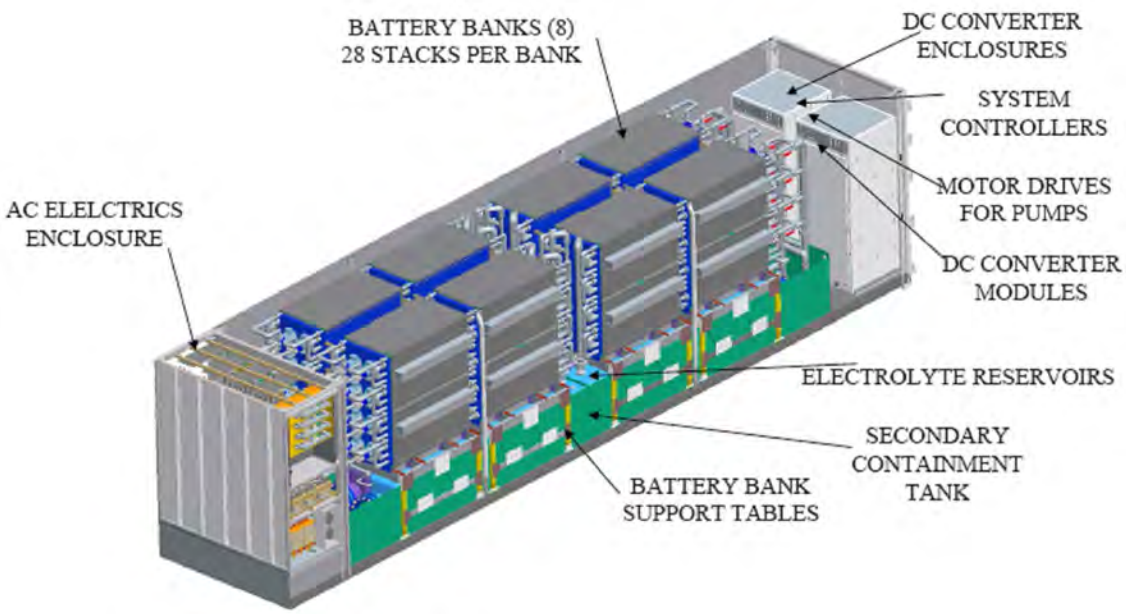
- Energy Storage subsystem – including the energy storage blocks, electrolyte tanks, and circulation system.
- Power Conditioning subsystem – includes four 125 kW grid-tied inverter/rectifiers and grid interconnections.
- System Controller – provides real-time monitoring, control, management and communication for the system. This system includes an energy management application that manages the charging and discharging based on user settable parameters.
- Thermal Management subsystem – provides active thermal management to maintain optimum temperature for all system components. The thermal management makes use of a chiller mounted at one end of the trailer and shown in the figure, below. The electrolyte reservoir contains a liquid-to-liquid heat exchanger used to remove heat during charge.



TransFlow 2000 – Main Subsystems

Section 2: Energy Storage

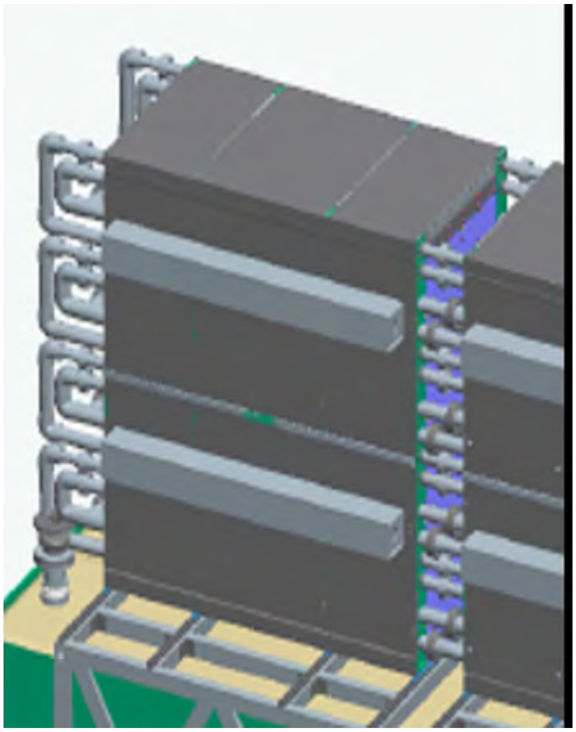
The energy storage system comprises 8 energy storage towers each consisting of 28 blocks. Electrolyte is stored in tanks below the towers and is circulated by motor driven pumps.



Energy Storage Tower Architecture

Each Energy Storage Tower contains 28 blocks, each consisting of 54 cells. The unit cell potential is ~1.8 V. Therefore, the 54-cell block is a 97.2 V energy storage device. Electrolyte is pumped to the blocks through a manifold distribution system. The manifolds are self-draining when the electrolyte pumps are off. However, electrolyte is retained inside cells with the pumps off by positioning the cell feed tubes coming off the manifold slightly above the entry port to each cell.

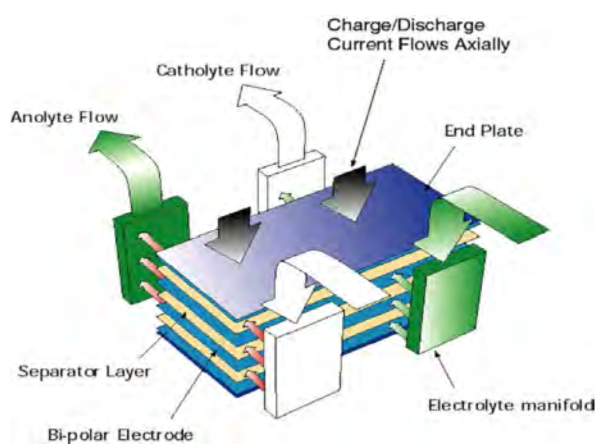
The block is constructed from bipolar electrode plates (anode on one face, cathode on the opposite face). The bipolar plate substrate is polyethylene filled with a high electronic conductivity carbon. A high porosity polyethylene separator lies between the anode and cathode.



Energy Storage Tower

Zinc Bromide Chemistry

In the Premium Power Corporation zinc bromide energy storage system, electrolyte is pumped from two electrolyte reservoirs through the battery block in two circuits, one for anode half-cells and the other for cathode half-cells. This is shown schematically to the right. The electrolyte in the anode loop is commonly called anolyte; the electrolyte in the cathode loop is called the catholyte. Anolyte and catholyte are in contact through microporous cell separators. Although ionic components in the electrolyte can readily pass through the cell separator, bulk mixing of anolyte and catholyte is prevented.



Energy Storage Cell

Initially the electrolyte is a homogeneous aqueous solution of zinc bromide, zinc chloride, potassium chloride and quaternary organic bromide salts. As the zinc bromide energy storage system is charged, zinc ion is reduced to metal on the anodes, and bromide ion is oxidized to molecular bromine on the cathodes. The anolyte and catholyte gradually develop different compositions. Elemental bromine produced in the cathode half-cells forms a polybromide complex with quaternary salts in the catholyte. The polybromide complex separates from the catholyte aqueous phase as a high-density oily liquid phase. This is collected in the bottom of the catholyte reservoir. The charging process stores chemical energy in separate locations, inside the battery block as zinc metal and outside the battery block in the catholyte reservoir as polybromide complex.

During discharge these processes are reversed. Zinc metal oxidizes reforming the zinc ion and bromine is reduced to bromide ion. Bromine available in the catholyte for reduction to bromide ion will be consumed in a short period of time unless polybromide complex from the bottom of the catholyte reservoir is fed back into the circulated catholyte. If the complex is not pumped back into the cathode half-cells, the block discharge voltage will quickly drop to a value too low to provide useful DC power.

The essential reactions in the zinc bromide energy storage system are:

Anode: $Zn (s) \leftrightarrow Zn^{+2} (aq) + 2e^-$ -0.76 V

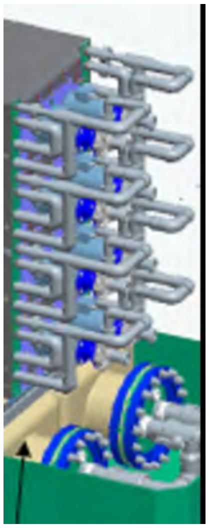
Cathode: $Br_2 (aq) + 2 e^- \leftrightarrow 2 Br^- (aq)$ +1.087 V

Overall: $Zn (s) + Br_2 (aq) \leftrightarrow Zn^{+2} (aq) + 2 Br^- (aq)$

Polybromide complex: $QBr^- (aq) + n Br_2 (aq) \leftrightarrow Q(Br_2)_nBr^-$ (water insoluble)

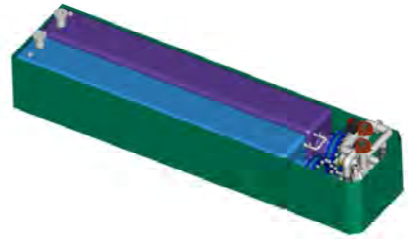
Circulation subsystem

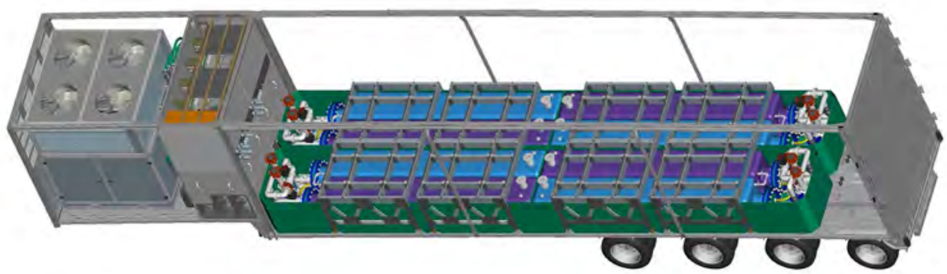
The electrolyte is pumped through the towers using AC Induction motors that provide speed control to optimize battery performance. The TransFlow 2000's energy storage tower is divided into eight groups. Each group has its own anolyte and catholyte pump, inherently providing system fault tolerance.

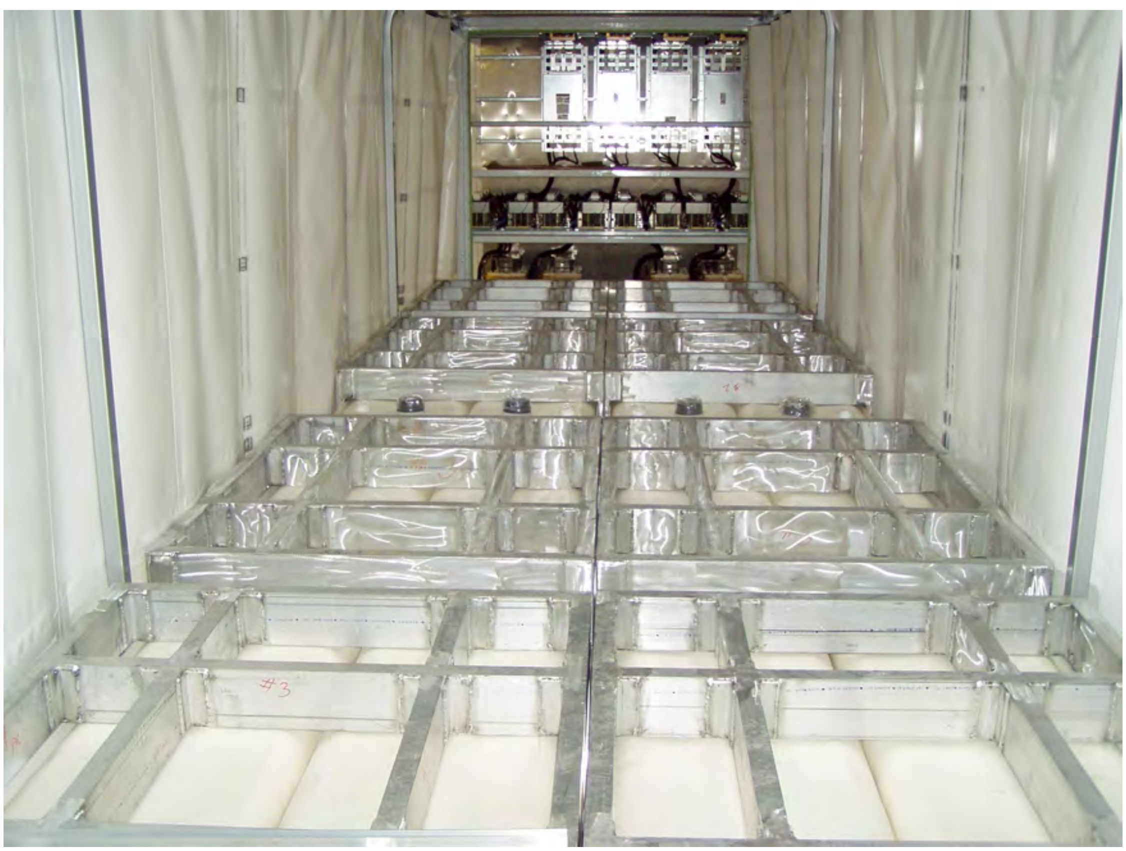


Electrolyte Reservoirs

The electrolyte is stored in eight separate reservoirs beneath the towers. Four anolyte reservoirs and four catholyte reservoirs. Each reservoir pair has its own secondary electrolyte containment tank and prime pump located at the end of the tank.

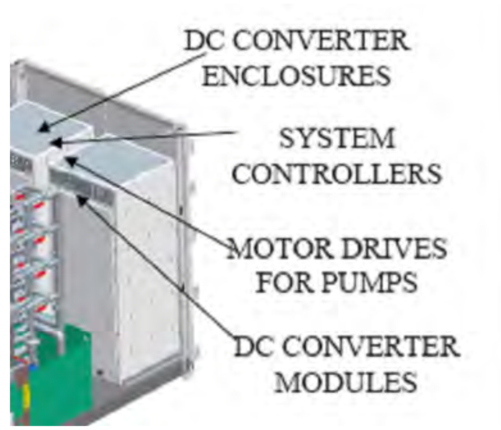






Charge/Discharge Control Electronics

Each tower in the energy storage system is separately controlled with a proprietary technology developed by Premium Power Corporation, thus ensuring optimal performance, during both charge and discharge. Each tower's control electronics has a DSP that monitors the tower's state, controls the operational mode, and regulates the voltage and current levels. The DSP communicates the towers status and receives system level commands from the system controller via a CAN bus connection.

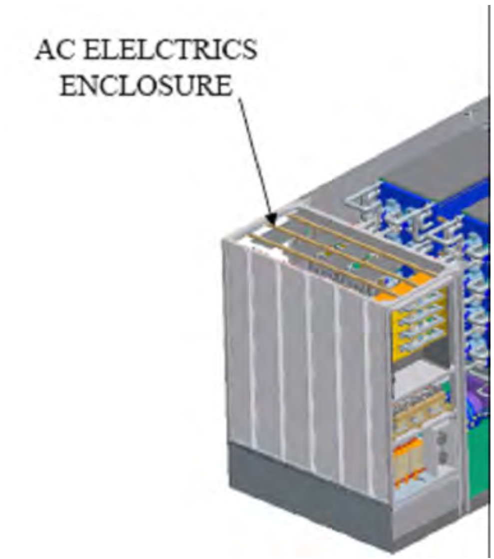


At the core of the electronics is an IGBT based, bi-directional half-bridge converter. When charging, the bridge operates as a buck converter, taking power from the high voltage DC Link and storing it in the towers. During discharge the converter boosts the battery voltage from the tower and returns power to the DC Link.

The DC Link is a laminated bus bar that distributes power between the energy storage towers and the power conditioning subsystem.

Section 3: Power Conditioning Subsystem

The power conditioning subsystem consists of two power conditioning units, each containing four 125 kVA inverter/rectifiers. Four inverter/rectifiers operate in parallel to provide 500 kVA of power to the grid from the internal dc link. They also are used to charge the energy storage subsystem taking power from the grid.

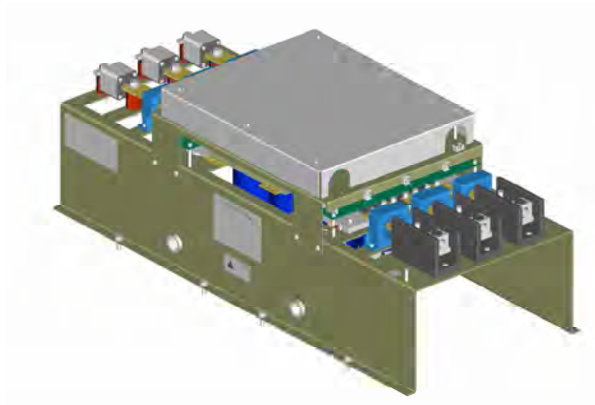


Each power conditioning unit has four 125 kW IGBT based inverter/rectifier units. These are mounted on a single core structure and controlled by a single DSP. In the TransFlow 2000, each inverter is capable of producing a 480 VAC three phase output at 125 KVA. These inverter outputs are able to be paralleled using droop control architecture, which provides scalability, redundancy and fault tolerance.

The ability to control a sine wave in both current and voltage gives the electronics a great deal of flexibility in its connection to the grid. Contactors are used to isolate the output from the grid in the event that the system is taken off line. Fault responses are also programmed so that a failure of the grid can be suitably mitigated. The electronics and control have the ability to sense an outage or short and try to reset the condition as in the case of a circuit breaker or to gracefully shut down should the fault not clear. It is also configured in its building block architecture as a fault tolerant system. Should a component or subsystem fail the fault is detected, isolated and the system recovers.

The system can also interface a micro grid in that it can stabilize various elements of such a grid. It will fill the gaps left by intermittent sources as well as stabilize fuel cell and turbine systems, which do not have the ability to follow a load.

Inverter/Rectifier



Three phase bi-directional solid-state converters are used to produce high quality AC waveforms. The same circuit is used to take power from the grid or deliver power back to the grid. High-speed switching technologies are used so that low harmonic distortion is realized giving an exceptionally clean power. In order to be effective as a power source in a grid application they also need to respond as the grid would. In the event of a short circuit they need to supply enough current to burn through a circuit breaker or fuse in the shorted branch, and have the electronics maintain control.

The ability to parallel inverter stages is made possible by the use of advanced controls. Premium Power Corporation has developed an inverter that utilizes Droop Control. Droop control allows each inverter to self-level in terms of load. Each inverter is programmed to supply synthetic or loss-less impedance so that voltage output is only a slight function of load. Since a more heavily loaded inverter will have a slightly lower voltage the other inverters will naturally supply more current. This allows the self-arbitration of power flow without the use of a single point of failure. Should one inverter fail the others will naturally take up the slack. No external communication is required from inverter to inverter.

Grid Interconnection

Each TransFlow 2000 has five 200A Hubble Insulgrip connectors using AWG 4/0 Type SC UL Rated flexible cable. These will be connected to a Power and Distribution Network (PDN) that will be designed and installed by a qualified electrical power contractor. This method has previously been successfully implemented in a major North American utility-owned substation and is a simple and reliable means of connecting a TransFlow to the grid. AC Disconnect switches are provided for all trailer and PDN connections.

Section 4: System Controller

The system controller provides real-time monitoring, control, management and communication for the system. The control architecture is implemented using an Intel Pentium class processor and a QNX realtime operating system. The system controller contains hardware to interface with pumps, valves, user interface panel and other system components. The system controller communicates with the energy storage and power conditioning sub systems via CAN bus. The controller coordinates the various subsystems to form an autonomous system that an operator can observe or program for a particular function. Power and load is continuously monitored and storage is charged or discharged according to the parameters that can be preset remotely by the user.

Data Telemetry

Each subsystem is integrated with the use of digital controllers that have the ability to communicate, command and control. Each aspect of the system is monitored for its health. Health is monitored at the component level, function level, and system level. Health and operational data is logged and telemetered real time to maintenance, service, and utility personnel. Additional observation points at key feeder and load points may also be monitored. These telemetry channels can be on the customer or utility intranet or can be made using wireless connections via CDMA modems. Overall thousands of variables are continuously monitored and can be made available as well as customer specific data reducing filters can also be implemented. A user can define the reporting it desires online and receive on the information they are interested in.

Energy Management

Among the functions that can be supplied is to supplement the power during on peak times or simply scheduled. The second type is that of level loading the feeder. Maximum power is set internally and the storage is used to feed to the load any power over and above the set limit. A third type is the ability to determine that spurious peaking is occurring. These can easily be filtered by storage being drawn from during the short duration peaks. The system has an internal algorithm that can distinguish between a general load increase and that of a transient load onset. The system keeps track of average power forming a power envelope and when power exceeds this envelope the peaks are “clipped” and the energy is drawn from stores. In a case where the envelope is exceeded for a long duration this power becomes the new envelope.

Interoperability

The system has multiple communications mechanisms for gathering information on system state and history as well as commanding and controlling the connection to the grid, and the charge or discharge rates. Each of these communication points is listed below.

There are three direct communication links available to the system:

- A direct Ethernet Tcp/Ip link which can be tied to any standard network.
- A CDMA Modem which can tie the Ethernet link directly to the Web.
- A Serial RS232/RS485 communications link primarily used for DNP3.

The communication links support the following software protocols:

- DNP3, either serial or Ethernet
- Web services over a secure socket layer (SSL)
- Web Application through a secure socket layer (SSL)
- SFTP over a secure socket layer (SSL)
- SSH, a secure command terminal
- Propriety data access with the Premium Powers Dash Board application.

These three communication links ultimately support two access points to the systems, the Ethernet link and the serial link which each support various communication protocols listed above and described in detail in the following sections.

The serial link:

The serial link supports DNP3 Level 2 communications. The system acts as an Intelligent Electronic Device (IED) and will be controlled and queried by a master Remote Terminal Unit (RTU).

All interactions and information exchange options will be detailed in a standard DNP3 mapping document. The software protocol stack was purchased from a DNP3 compliant vender and integrated into the system software, essentially guaranteeing adherence to the standard.

Features:

- The system can be configured to run various charge/discharge/hold cycles and be queried for state and performance information.
- The system can be configured to disconnect from the grid (fail safe mode) if there is any communication failure between the master RTU and the system.
- DNP3 is a NIST recognized standard for SmartGrid implementations
- Implementation of a proven protocol stack guarantees protocol adherence

The serial access point is for system control and monitoring. If a failure occurs which requires service, access via the Ethernet port will be required if software updates are necessary.

The Ethernet Tcp/IP link:

The Ethernet links is capable of supporting the full array of communication mechanisms available with this technology. This capability lends itself to a large set of potential security risks that will be addressed in detail in the section on Cyber Security that follows.

The Ethernet link is the primary access point for the system. Once administrator access is achieved through a secure terminal application such as SSH the entire system can be completely controlled. This level of remote control allows for comprehensive service to be achieved remotely.

Supported Applications, Services, and Features:

- SSH, a secure terminal shell
  - Allows command line access to the operating system
  - Used for service and software updates
- SFTP, a secure file transfer protocol
  - Used for software updates and secure data retrieval
- HTTPS, web services over a secure socket layer
  - Access to the Command and Control application
    - Allows for remote servicing, fault monitor and analysis
  - Supports WEB Service commands
  - Supports WEB Service data retrieval
- DNP3 over Ethernet
  - System is defined as an Intelligent Electronic Device (IED)
  - All the benefits of the serial DNP3 via the Ethernet link.
- PPC Dashboard
  - Graphical Application for viewing status and history of the system.

The DNP3 protocol and the web services are both standard technologies that allow for consistent integration options. Either of these technologies enables smart grid interoperability.

The complete control of the system allowed through SSH guarantees that system upgrades and maintenance is quickly and easily accomplished.

Cyber Security

A comprehensive consideration of cyber security requires that systems are secured from conception and engineering, through production, and all the way to installation and long-term maintenance. Therefore security concerns are not limited to direct attacks on the system, but are also inclusive of

- Company policies with regards to protection of computer systems, product designs and information.
- The protection and maintenance of encryption certificates.
- Engineering practices implemented to insure that a multitude of unexpected small faults would not disrupt the grid in a significant way.
- Access to the system for maintenance and system update procedures.
- As well as direct cyber attacks to the installed system.

The following section point out and address's various applicable security concerns during the three main stages of the product lifecycle; engineering, production, and installation/servicing.

Security during the Engineering process:

In order for the final system to be secure the information for designing, building, and accessing the system must all be secure. Unsecured access to information at any point within the project would allow for a multitude of unnecessary security risks.

Information Security

The company will follow the practices outlined in the ISO/IEC 27000-series family of standards. These standards outline a best practice security management for information security as well as building and site security. Adherence to this policy will essentially secure all the information created during the design, build, and commissioning of the systems.

The remainder of this section assumes that the company itself has secured the premises and the computer systems. Therefore, procedures and processes during the engineering, building, and commissioning phases are all assumed to be secure.

Designing a secure system

During this portion of the lifecycle careful consideration of the system access points need to be planned and implemented.

On the Trans Flow 2000 there are essentially two access points designed into the system. The first is the serial communication used for the DNP3 protocol. By the nature of the technology this network is inherently secure. It is up to the installed customer to setup and control physical access to this link. The customer has complete, isolated control of the system via this network. The security risks are more likely to be at the level of the master SCADA control, of which the customer will be responsible for securing.

The second point of access is the Ethernet link. This technology has the potential to open up many security risks and care must be taken to secure access to this communication link. The security of this link is handled in two essential steps; the first is to control access to the system through a firewall, the second is to carefully setup the system to only allow access to a discrete set of secure applications.

Secure Access to the System:

There are two common ways of connecting the Ethernet to a network; the customer can connect the system to their network, or a CDMA modem can connect the system directly to the World Wide Web.

The first, and preferred method is for the customer to connect the system to their secured network. This allows the customer to control and monitor all traffic that is allowed to the system. The caveat is that Premium Power would need to be granted access to the customers network in order to perform system maintenance and updates. This option is inherently more secure since only authenticated users will be able to access services on the system.

The second is to connect the CDMA modem to the Ethernet hub and allow anyone on the Web to access the system. This method inherently depends the system itself to verify authenticated secure access to its services.

Securing Applications on the System:

Once a user has access to the Ethernet communications link, the additional security step of verifying and authenticating the user is dependent on the system itself. This is handled through the use of encryption technologies, security certificates, and specifically the Secure Socket Layer (SSL v2).

There are essentially five applications that are enabled on the system:

- SSH, a secure terminal shell (depends on SSL)
- SFTP, a secure file transfer protocol (depends on SSL)
- HTTPS, web services over a secure socket layer (depends on SSL)
- DNP3 over Ethernet (if enabled)
- PPC Dashboard

The first three applications; SSH, SFTP, & HTTPS are critical access points to the system. These access points could be catastrophically used if compromised and therefore must be correctly configured and managed. Access to these services requires the creation and distribution of encryption certificates that will allow the system and the user to identify and verify each other. The security of these services is dependent on the security of the certificates. Therefore the management and distribution process of the certificates must be defined and secure.

The DNP3 over Ethernet application has no security measures at this time. Therefore, if enabled, it would be up to the customers to secure access to the system through their own internal network and firewall.

The PPC Dashboard only allows for retrieval of data. There is no way for the system to be effected by users who access this service.

Security in Production and Commissioning:

The critical step's that occurs in this stage is the implementation, configuration, and verification of the security steps defined during the engineering phase.

During the build of the system, the software and operating system are actually installed, the specific services are enabled, and the encryption certificates are created. If any of these procedures are not done correctly, unnecessary security vulnerabilities will be created.

In order to address the potential security risks three separate procedures will be defined.

The first process will document the build and installation of the operating system (OS). At the completion of this process only the applications defined will be running on the target system and all other ports will be disabled.

The second process will document the creation of both the server SSL certificate as well as the one or multiple client certificates. A secure location will be identified to archive these and maintain these certificates.

The third process will document a checklist of configuration and security settings on the target OS. This checklist will be signed off and saved as proof that the security system is fully intact. The checklist will verify the correctness of the startup scripts, the certificate installation, and that all software is up to date with new software and applicable security patches.

Security and Maintenance of installed systems:

During this phase of a product it is important that the customer is aware of the potential security risks. We must work closely with the customer to ensure that the system is secure and that all required access points are functional and correctly authenticating valid users, and denying invalid users.

The following sections describe the anticipated procedures required for installing, configuring, verifying, and maintaining a secure system.

Installation:

The preferred method will be for the customer to connect the Ethernet Tcp/Ip port to their secured network. Once connected, encryption keys will be required on all the computers the customer will connect to the system. Once installed, access will need to be verified.

Under this configuration a solution will be required which will allow Premium Power to access the system through the customers network for service and maintenance procedures.

If the CDM modem will be used it must be correctly configured such that only the required ports are forwarded to the system. Then all computers that will access the system must have the required encryption keys installed. Once installed, access will need to be verified.

In addition, all logging and reporting procedures will be verified. This includes verifying that the paging process is working correctly and that the list of users to page has been created.

Support and Maintenance:

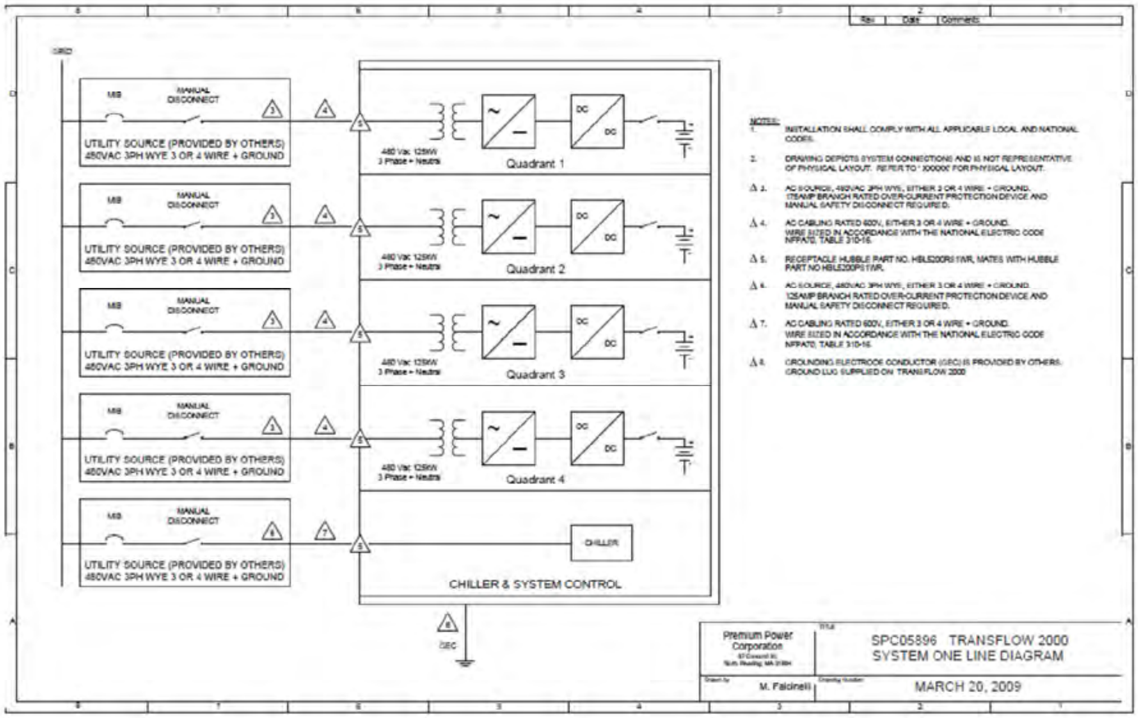
Once operational, the system is continuously monitoring and logging the health of its self, the power at the grid connection, and any required watchdog communications. Any fault conditions will be immediately handled in a predefined manner by the system and if required page/emails will be sent to a predefined list of users alerting them of required actions.

The Trans Flow 2000 is continuously logging data generated by the system. This data is inclusive of items such as grid voltages, currents, battery charge states, fault condition and a myriad of additional information useful to a service engineer or a smart grid. All of this information is securely accessible to a user through the HTTPS commander. It is also accessible to the smart grid through protocols such as DNP3, or through the web services. This data can be analyzed real time or offline and then applicable actions can be either commanded back to the system or acted upon by the service engineers.

If hardware faults or maintenance procedures are required, they would be scheduled as with any product.

If software faults or improvements are required, or if security issues have been identified, they will be handled remotely through the SSH secure terminal service. This remote terminal allows the software engineer to install updated software or security patches. The system will also allow certificate revocation list or updated certificates to be installed.

One-Line Diagram



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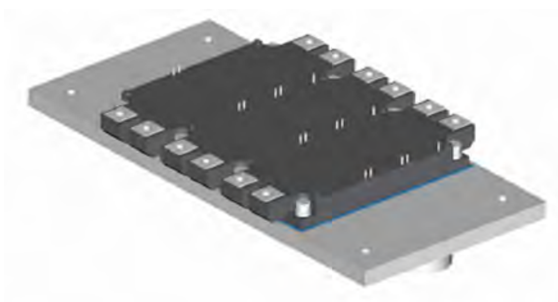
Section 5: Thermal Management Subsystem

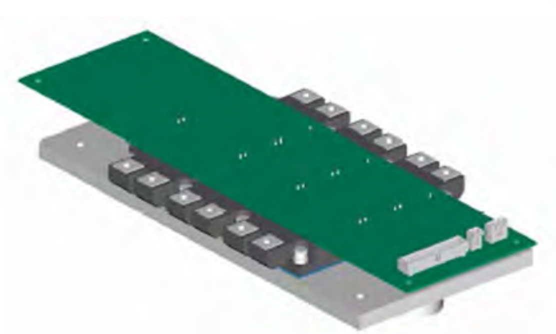
The TransFlow 2000 uses an active thermal management system to maintain optimum temperature for all system components. The thermal management makes use of a chiller mounted at one end of the trailer and shown in the above diagram. The electrolyte reservoir contains a liquid-to-liquid heat exchanger used to remove heat during charge. The heat exchange liquid is eco-friendly water-propylene glycol mixture. Electrolyte does not circulate through the chiller coolant loop. This approach allows the system to operate outdoors in all weather environments. The cooling system can be used primarily at night when the excess power is cheap and not used during discharge when power is more expensive.

In addition to cooling the electrolyte, the thermal management system also cools the power electronics. This is achieved by the use of advanced low cost liquid cooled heat exchangers that are integrated directly with the power electronics packages reducing cost, parts count and the need for more advance systems.



This increases reliability by controlling the temperature of the junctions within the power devices, as well as reducing overall size so that the systems is packaged directly with low parasitic inductance busbars, further reducing the overall complexity of the system. A diagram showing the mounting of IGBT to heat sink is shown.

The cooling is connected by an integral inlet located underneath the power module as shown in the diagram. This allows for easy assembly and inexpensive interconnect for both power and cooling.



Section 6: Specifications

Performance:	
Energy Storage Capacity:	2.8 MWh
Voltage Input (3-Phase):	480VAC, 60Hz
Voltage Output (3-Phase):	480VAC, 60Hz
Maximum Continuous Power Delivery:	500kW
Power Factor (Input):	+/- 0.95
Voltage Harmonics:	<5% THD
Physical:	
Length:	53' (16.15m)
Width:	8.5' (2.59m)
Height (including trailer wheels):	13.5' (4.11m)
Weight:	130,000 lbs
Safety:	
Underwriters Laboratories	UL 1741
Federal Communications Commission	Part 15, Class A
National Fire Protection Agency	NFPA 1 & 70

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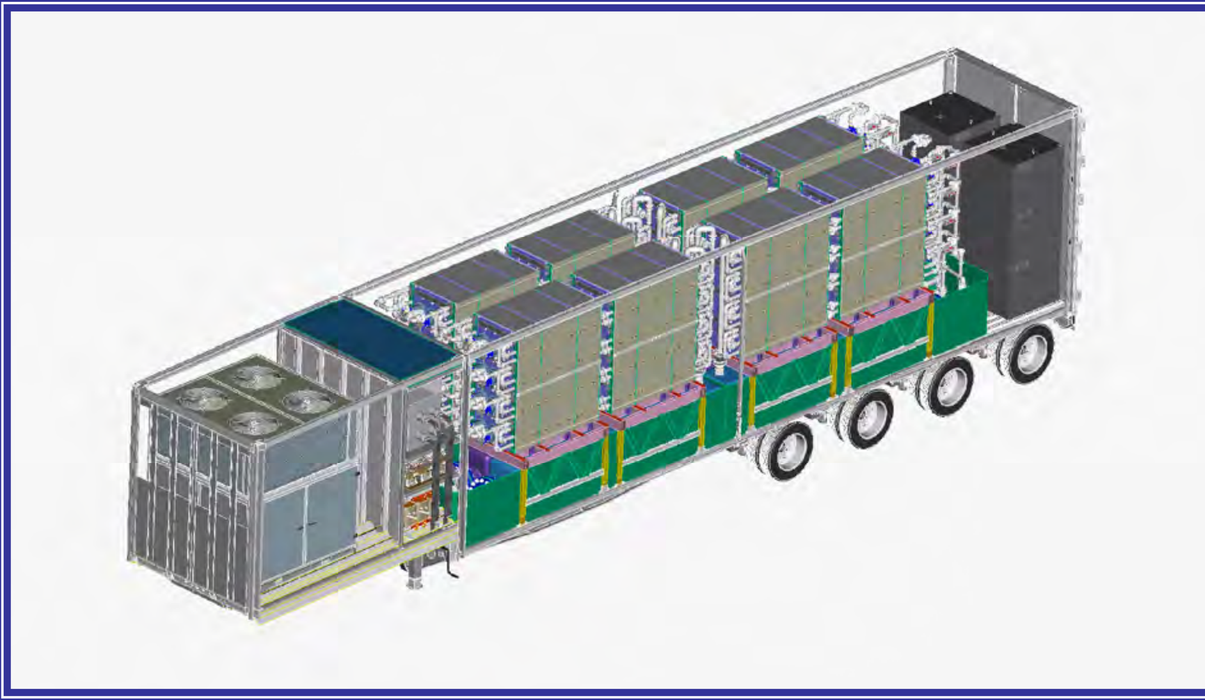
Document DES-TF2000
07-2010

Premium Power

TransFlow 2000

Utility-Scale Mobile Energy Storage System



PREMIUM POWER'S TRANSFLOW 2000 DELIVERS THE MOST FLEXIBLE & EASY TO INSTALL, FULLY INTEGRATED, LARGE-SCALE ENERGY STORAGE SOLUTION.

Integrated, Turnkey Solution

Premium Power's TransFlow 2000 is a fully integrated system that comprises energy storage, power conditioning, system control and thermal management subsystems packaged into a portable, turn-key, building block to be placed wherever it is needed for immediately dispatchable on-line energy storage. Systems can be placed outdoors or indoors.

Each system has the capability to store up to **2.8MWh** of energy and instantly dispatch at **500kW** for at least **5 hours**.

Zinc-Flow Advantages

The TransFlow 2000 is a low cost solution that delivers the required performance at an affordable cost without endangering our environment.

This is made possible because of Zinc Flow technology's unique advantages:

- ***Low initial cost*** – major components use consumer-grade plastic
- ***Low maintenance needs / costs*** – equivalent to $0.004/kWh
- ***30+ year life***
- ***Unlimited cycling*** - including 100% and partial discharges
- ***Environmentally friendly*** – 100% recyclable or disposable

Premium Power

Applications

The TF2000 meets the needs of:

- ***Electric utilities:***
  - Substation T&D asset deferral
  - Distribution system load support
  - Peak shaving
  - Demand response management
  - High quality power output
  - Energy arbitrage
  - Ancillary services

  -increasing system reliability and operational flexibility while reducing carbon emissions and enabling new business opportunities via innovative engagements with customers.
- ***Renewable energy generators:***
  - Time-shifting of generated energy
  - Energy arbitrage
  - Ancillary services

System Configuration

The overall system comprises four fully integrated subsystems:

- Energy Storage – including storage blocks, electrolyte tanks, and pumps.
- Power Conditioning – includes four 125kW grid-tied inverter/rectifiers and grid interconnections.
- System Controller – provides real-time monitoring, control, management and communication, with remote access.
- Thermal Management – provides active control of temperature for all system components

Grid Interconnection

Each TransFlow 2000 has four 200A Hubble Insulgrip connectors using AWG 4/0 Type SC UL rated flexible cable. AC disconnect switches are provided for all trailer and PDN connections.

Specifications

Performance:	
Energy Storage Capacity:	2.8 MWh
Voltage Input (3-Phase):	480VAC, 60Hz
Voltage Output (3-Phase):	480VAC, 60Hz
Maximum Continuous Power Delivery:	500kW
Power Factor (Input):	+/- 0.95
Voltage Harmonics:	Approx. 1.5% THD
Physical:	
Length:	53’ (16.15m)
Width:	8.5’ (2.59m)
Height (including trailer wheels):	13.5’ (4.11m)
Weight (including electrolyte and trailer):	108,000 lbs (43,545 kgs)
Safety:	
Underwriters Laboratories	UL 1741
Federal Communications Commission	Part 15, Class A
National Fire Protection Agency	NFPA 1 & 70

Remote System Management

Web-based remote monitoring enables operator access to continuously monitored parameters, with automated notification by page, text-message or e-mail in the event of a fault condition.

Autonomous system control enables power and load to be continuously monitored and storage charged or discharged according to parameters that can be remotely preset by the user.

Energy Management application makes buy (charge) or sell (discharge) decisions based on real-time wholesale market pricing and user configurable parameters.

Premium Power Corporation

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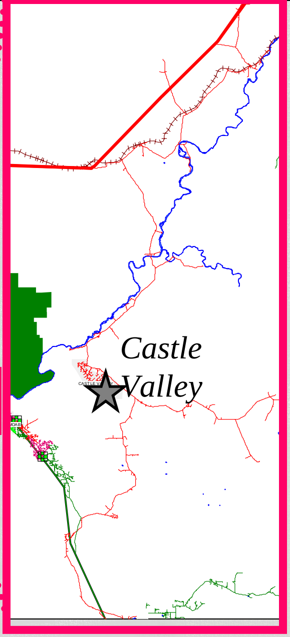
2-MWh Flow Battery Application by PacifiCorp in Utah

Mark T. Kuntz
VP Marketing & Business Development
mkuntz@vrbpower.com

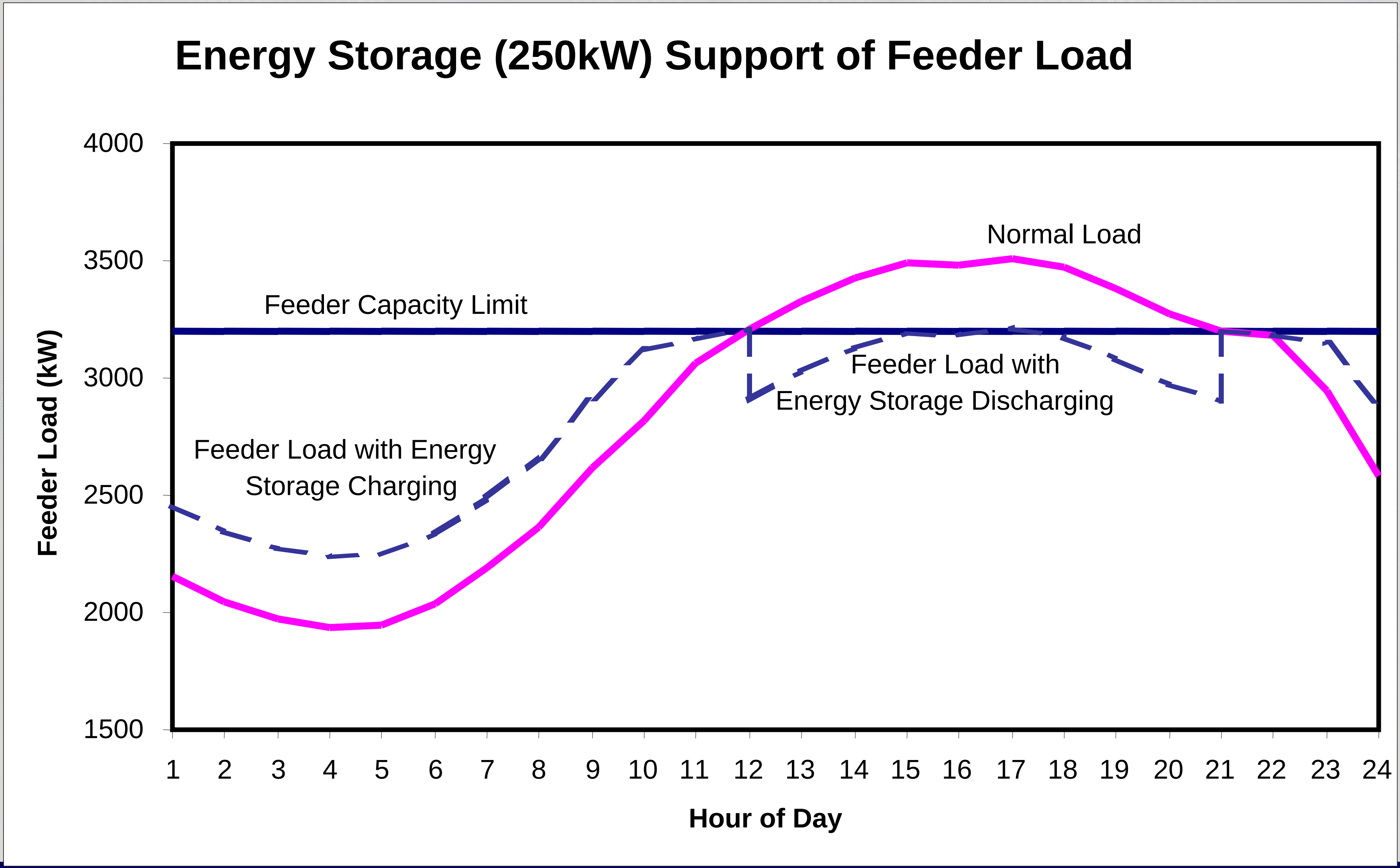
California Energy Commission Staff Workshop:
Meeting California's Electricity System Challenges through Electricity Energy Storage
February 24, 2005

Rattlesnake#22
25kV Feeder



- Environmentally Pristine Southeast Utah
  - East of Moab
  - East of Arches National Park
  - Along Colorado River valley
- 209-mile long 25kV feeder, with 3-line regulators & 7-reclosers
- Possible denial of new connects because feeder cannot supply any significant amount of new load without causing low voltage to existing customers.
- Because feeder is so long, reliability and power quality led to Public Service Commission Complaints. PacifiCorp agreed to fix.
- Traditional alternatives to add capacity and improve service were very costly and environmentally difficult.
- Demonstrated distribution benefits of VRB energy storage as part of PacifiCorp's DG Strategy – 2 MWh, 250kW VRB-ESS (expandable to 1MW) in Castle Valley, Utah

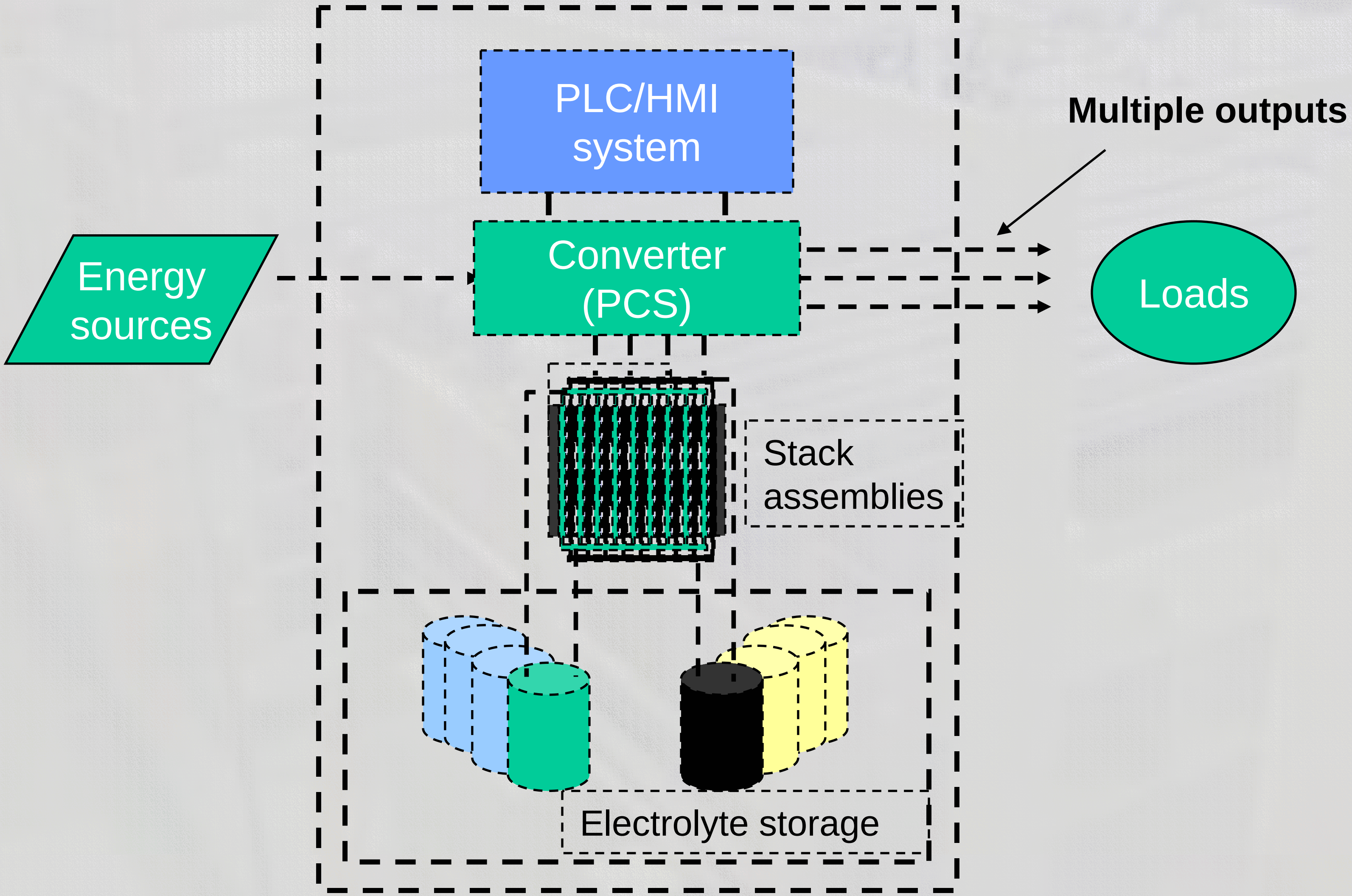
Daily Load Profile



What is a Flow Battery?

- An electrochemical *energy storage system*
- Electrolyte is stored outside the cell stack, so power and energy are independent
- Based on a reversible chemical reaction within a sealed system
- Electricity can be stored indefinitely in a liquid with very low self discharge
- Energy can be recovered almost instantaneously (< 5ms)

Flow Battery Components



Technical Advantages of Flow Batteries

- High-energy efficiencies: 70% round trip.
- Storage capacity can be easily increased by adding electrolyte.
- Designed for unattended operation with very low maintenance costs ($0.008/kWh).
- Ambient/Low operating temperature.
- Can be discharged and charged >13,000 times without performance degradation.
- Intelligent, programmable PCS provides four-quadrant control and simultaneous real and reactive energy (VARs).

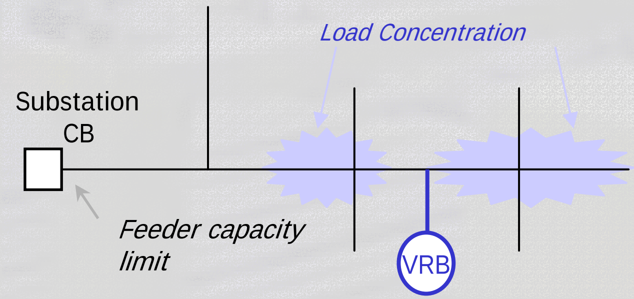
Environmental Advantages

The Green Battery

- No heavy metals such as lead, nickel, zinc and cadmium
- No air emission; minimal sound emissions
- Electrolytes have indefinite life
  - No disposal issues
  - Completely reusable
- PVC piping system
- Fiberglass tanks

Cost Benefit Analysis

- Alternate line and substation costs - $4million with 3 year lead times
- Diesel Engine – (DG) - polluting , difficult to permit, long distance from fuel supply
- CAPEX $500/kWh (first in USA)
- O&M $0.008/kWh discharged
- VAR support – regulation control reduces need for switched capacitors
- Reduces line losses by ~40 kW
- Charge at night, discharge on peak – arbitrage value



Cost Benefit - Capital Deferral (continued)

- Capital deferral - 7.5%, 10 years. Cost of upgrade $4 million
- Cost of VRB-ESS = $1,000,000 ($500/kWh)
- Arbitrage savings – 3 to 4 c/kWh = $17,280/year
- Net Annual savings = ($4 million - $1 million) x 7.5% plus arbitrage savings = $242,420
- IRR = 20% (before tax, unleveraged, 10 years)

PacifiCorp Flow Battery Future Plans

- Advanced application development:
  - Advanced power quality applications
  - Advanced islanded operations
  - Adaptive charge/discharge energy arbitrage control algorithms
  - Advanced dynamic voltage control algorithms
  - Dynamic stability control algorithms
  - Wind farm application studies
- Increases to capacity through:
  - Additional cell stacks
  - Higher capacity inverter
  - Increased molarity of the electrolyte
- Can relocate to new site once transmission line and sub is built
- Investigating future telecom site and substation battery replacements

Clean Energy Storage – and Onions?

Introduction

What do onions and energy storage have in common? They are key ingredients in a well engineered and creative renewable energy system. In December 2010, Prudent Energy announced that it would install a 600-kilowatt Vanadium Redox Battery (VRB®) energy storage system at one of the largest fresh-cut onion processing plants in the world. Gills Onions, located in Oxnard, California, will use Prudent Energy's patented VRB® technology and know-how to reduce electricity costs and build on its award-winning sustainable energy program, which serves as a model for the food industry.

Gills Onions

Gills Onions operates one of the largest, most innovative and sustainable fresh-cut onion processing plants in the world. At their 14-acre processing facility in Oxnard, more than 90,000 tons of yellow and red onions are peeled and processed annually using proprietary equipment and processes to deliver premium fresh-cut onions to industrial, foodservice, retail and consumer markets.

According to Gills, "Innovation and technology is in our DNA". They were asked by La Victoria® Salsa to figure out a way to provide large quantities of high-quality, fresh-cut onions when no automated equipment or processes existed. With a typical farmer's "can do" attitude, Steve and David Gill developed a system in 1983 to peel, slice, dice, and deliver the first fresh-cut onions in the food processing industry.

Waste to Energy

In 2009, Gills became the first food processing facility in the world to produce ultra-clean energy from the unusable portion of the fresh-cut onions – converting 100% of their daily onion waste (up to 300,000 pounds) into renewable energy and cattle feed, reducing greenhouse gas (GHG) emissions, and saving in annual electricity costs.

The Advanced Energy Recovery System (AERS) that went into operation in July 2009 converts all of the daily onion waste into a combination of renewable energy and cattle feed. The AERS eliminates the formerly labor intensive and expensive process of hauling onion waste to farm fields, where it was worked into the soil. Environmental benefits extend to the local community, the state of California and beyond, with profound implications for agricultural food processors around the globe.

The new system extracts the juice from the onion peels and treats it in a high-rate anaerobic reactor to produce methane-rich biogas that powers two 300-kilowatt fuel cells. The resulting electricity is used to power the onion processing plant, saving an estimated $700,000 annually in electrical costs. The remaining onion pulp becomes valuable cattle feed without further processing.

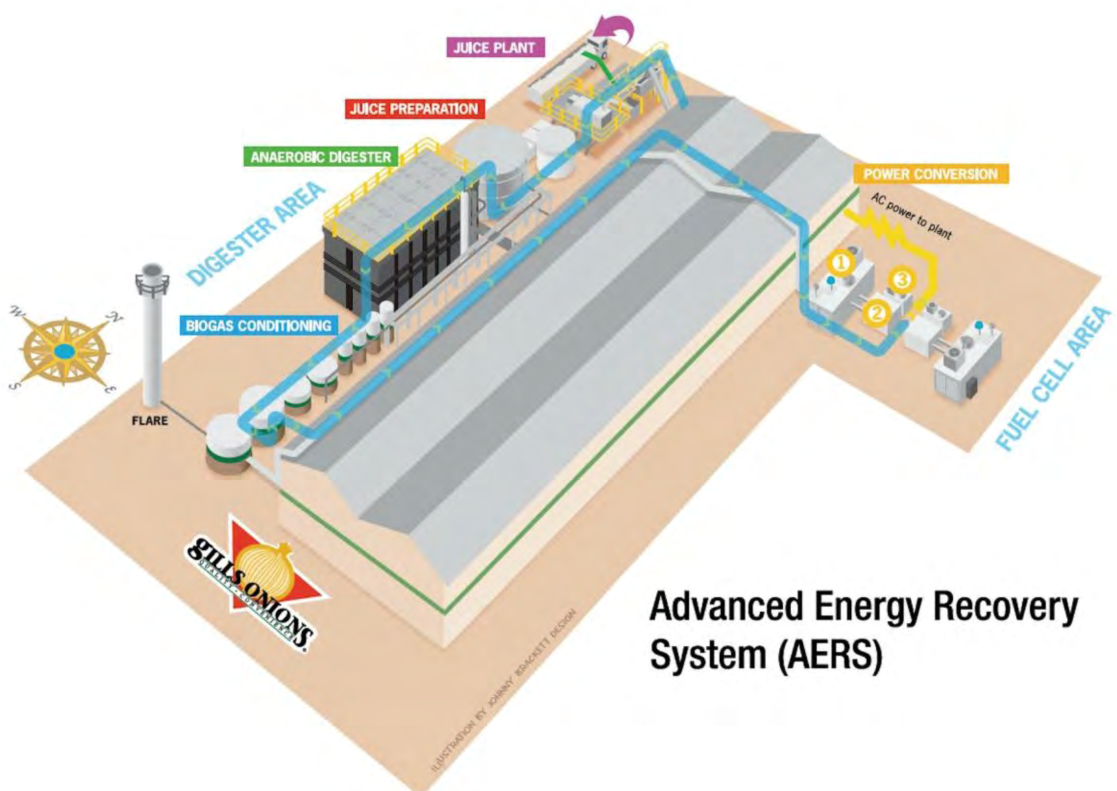


Diagram Courtesy of Gills Onions

Additional savings come from the elimination of $400,000 in annual costs associated with hauling onion waste to farm fields. Greenhouse gas emissions are reduced through the elimination of hundreds of truck trips on California roadways that moved this waste stream each year. The result is increased energy independence, elimination of a significant waste stream, reduced operational costs and a smaller carbon footprint. The combination of the energy produced, cost savings generated, and grant funding for renewable energy projects will result in a full payback of the $10.8 million total system cost in less than six years.

Energy Storage

Gills became interested in adding energy storage to the AERS for a number of reasons, and committed to Prudent Energy's Vanadium Redox Battery Energy Storage System (VRB-ESS®) as the best solution for their application. Installing the VRB-ESS® alongside the AERS will improve the efficiency of the system, provide clean back-up and emergency power, and further reduce their electric costs.

Time of Use Rates

Gills Onions' main motivation was the opportunity to reduce costs by shifting electricity generation from off-peak to on-peak periods. The electric utility, Southern California Edison (SCE), uses rate tariffs that increase the cost for energy during high use periods, typically during a 6 hour period in the afternoon. Most of the electricity on the SCE system is provided by power plants that operate around the clock, like nuclear and combined cycle natural gas plants. As the load increases during the afternoon, SCE is forced to call on more expensive generators, like simple cycle natural gas turbines. This additional cost is passed through to the customer in Time of Use (TOU) rates.

Although Gills was generating its own electricity, the company still depended on SCE for additional energy beyond what was produced by the fuel cells. In addition, electricity usage at Gills tended to increase during the most expensive on-peak periods, which is typical of many industrial customers. Therefore, by charging the energy storage system at night, and then discharging that power during the afternoon, Gills reasoned they would be able to reduce the cost of expensive on-peak power from SCE.

Demand Charges

SCE also has a demand charge that varies by TOU. Unlike the charge for energy, the kW demand charge is assessed for the peak use during the month, as measured in 15 minute intervals. For example, the Gills plant may have a fairly steady power usage, as would be typical for a 24 hour food processor, varying between 1,000 and 1,200 kW. However, if a number of motors or compressors kicked on at once, the usage during the 15 minute period could spike, and the measured demand could increase by 300 to 500 kW. *This short spike in power would then set the demand for the month*. The demand charge is also assessed based on time of use. For example, the on-peak demand could be three times as high as the off-peak. Energy storage thus can be used to reduce these spikes in demand – discharging as needed to compensate for additional power spikes.

Incentives

The State of California is encouraging the installation of certain types of energy storage with cash rebates. California is a leader in renewable energy and has required their regulated utilities, like SCE, to supply 33% of their electricity from renewable sources by 2020. However, the growth of intermittent renewables, like solar photovoltaic and wind turbines, is causing significant problems for the transmission and distribution operators. Energy storage is seen as one of the best solutions. As a result, substantial cash rebates are available to energy storage systems meeting stringent criteria. Among other requirements, the systems must be:

- Commercially available, and not just research or demonstration projects
- Able to charge and discharge electricity, multiple times per day as needed, to follow customer load
- Able to provide at least 4 hours of continuous energy at rated capacity
- Warranted for 5 years

Prudent Energy and the VRB-ESS®

After researching alternatives for over a year, Gills Onions decided on the Vanadium Redox Battery (VRB®) from Prudent Energy.[1] The VRB-ESS® is distinctive from other energy storage systems in several respects, including the ability to charge and discharge 100% of its capacity, for almost an unlimited number of times without damage.

Technical Description

Prudent's "flow battery" is rechargeable – like a car or cell phone battery – but that's where the similarities end. The VRB-ESS® is based on the company's patented regenerative fuel cell technology that converts chemical energy into electrical energy. Unlike conventional batteries that store their reactive materials within the cells, a flow battery stores energy-holding electrolyte in tanks, one for positive reactions and another for negative.

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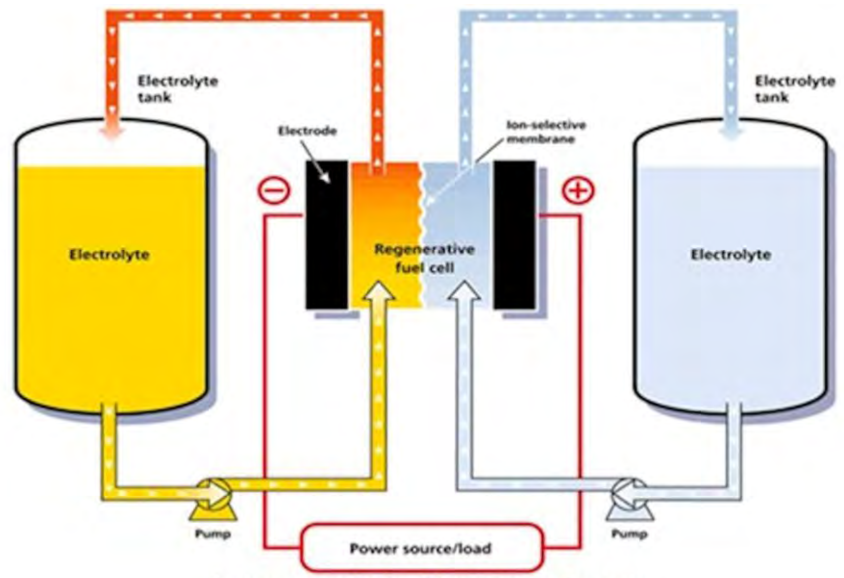
[1] Prudent Energy Corporation, a Delaware corporation with its headquarters in Bethesda, Maryland, is a wholly owned subsidiary of JD Holding, Inc., which in turn is owned by prominent U.S. venture capital firms and other leading venture investors. In January 2009, Prudent Energy announced its acquisition of the assets of VRB Power Systems Inc. This acquisition included the purchase of all patents, trademarks, know-how, equipment and most of the material owned or controlled by VRB Power. As of September 2011, Prudent Energy has over 40 far-reaching patents worldwide encompassing core cell stack designs, electrolyte composition, system designs, as well as several application patents including use with wind farms, off-grid applications and smart grids. VRB®, VRB-ESS® and VRB ENERGY STORAGE SYSTEM® are registered trademarks of JD Holding, Inc. JD Holding, Inc. is the owner of U.S. Patent Nos. 6,143,443, 6,468,688, 6,562,514, 7,078,123, 7,181,183, 7,184,903, 7,227,275, 7,265,456, 7,353,083, 7,389,189, 7,517,608 and corresponding foreign patents. Additional patent rights are pending.

The principle of the VRB® is shown in more detail below. Electrolytes are pumped through "cell stacks" creating an electric current. The positive and negative electrolytes do not actually mix together; a thin membrane separates them so that only selected ions "flow" through the cells. Each stack consists of many cells, which in turn contain two half-cells that are separated by the membrane. In the half-cells, electro-chemical reactions occur on inert carbon felt electrodes to produce the current that charges or discharges the battery. Ultra-light bipolar plates made from expanded graphite are also used to allow for good electrical conductivity and chemical resistance. This "re-dox" process is reversible, allowing the battery to be charged and discharged repeatedly.



Concept of a Redox Flow Battery System

Prudent's cell stacks are assembled like Lego® pieces to build half (100kW) and full (200kW) VRB-ESS® modules as well as custom-sized systems. The 200kW modules are then connected in parallel configurations to create MW-Class VRB-ESS® installations. As a result, the size, quantity, and storage capacity of the VRB-ESS® can be configured in highly flexible fashion, from a unit as small as 5kW (primarily for the telecommunications market) to utility-class systems of up to 10MW with long storage durations of 2-10 hours.

Vanadium Electrolyte

Energy in a VRB-ESS® is a separate asset and does not deplete in the way energy is normally lost from other battery systems. Prudent's system stores energy chemically in different forms of a single element – Vanadium – in a proprietary electrolytic mixture.[2] The Vanadium electrolyte is held in standard-size plastic storage tanks. The storage tanks hold exactly the same liquid chemistries, so there is no cross-contamination or rebalancing of the electrolyte. The electrolyte does not contain any heavy metals like lead, nickel, zinc or cadmium. There is no environmental disposal requirement. The electrolyte is not flammable. There are virtually no emissions from the system. The entire system runs at low pressure and room temperature, anywhere from 50 to 90 degrees Fahrenheit. And because the electrolyte doesn't degrade, it is reusable – an asset that retains its value for the owner.

Storage duration in a VRB-ESS® thus becomes simply a function of the amount of electrolyte in the storage tanks. In other words, unlike Zinc-Bromine or Lithium-ion batteries, *a VRB-ESS® affords completely independent scaling of power (kW) and energy (kWh)*. Sizing of the system can be tailored to a number of factors, such as the capacity of the onsite renewable energy installation or duty cycle requirements.

Power Electronics and Controls

The Power Conversion System (PCS), which converts raw DC current into usable AC current while charging and discharging the battery, is fully integrated into Prudent's system. All electrical components for any VRB-ESS® installed in the United States are UL approved. The VRB-ESS® is also controlled by a Programmable Logic Controller (PLC) and a Human Machine Interface (HMI) – essentially highly durable computers – that offer a fully automated, remote Supervisory Control and Data Acquisition (SCADA) system to control times and rates of system charging, and to receive real-time data on electricity prices so as to maximize the economic use of the system.

Unlike any other type of storage system, the VRB-ESS® can operate at a known and defined State of Charge (SOC), allowing the system instantaneously to ramp up and down without any ill effect on life. This unique feature is essential for balancing power where a fully charged battery can be used to absorb energy. SOC can be set and verified at all times, on line. As a result, the VRB® is *always on* and can be cycled as many times per day as required.

[2] Vanadium is not scarce. It is a transition metal, which means it has the typical properties of metals, but in addition high melting and boiling points, and high density.

Operational Benefits of the VRB-ESS®

The VRB-ESS® is capable of meeting precise energy and power demands of almost any size. If, by comparison, you were to connect a long series of conventional (e.g., lead-acid) batteries, that string would inevitably be weakened by the differing energy levels within each independent cell. A VRB-ESS®, on the other hand, contains cells with nearly identical characteristics, since they all share the same energy-bearing electrolyte. This makes the upper limit of the energy-to-power ratio of a flow battery virtually unlimited.

Prudent's VRB® is distinct from hybrid flow batteries (such as zinc-bromine or sodium-sulfur, for example) which have one reactive electrode and therefore suffer from the degradation drawbacks of conventional batteries. Using *only* Vanadium in the electrolyte – as opposed to a blend of electrochemical elements – gives Prudent's advanced battery systems the most competitive advantage in terms of operating cost, system life, maintenance, and safety.

Application to Gills Onions

The VRB-ESS® at Gills Onions will consist of three 200kW modules with enough electrolyte to provide 6 hours of storage. This will allow the VRB® to provide 6 hours of energy at 600 kW (3.6 megawatt hours) during the expensive on-peak utility rate period. The system can be expanded in the future as needed by adding additional 200kW modules and/or additional electrolyte.

In addition, the VRB® will respond to spikes in usage to reduce demand charges. The VRB® can change from fully charging to fully discharging in seconds, so the full 600 kW is available 24 hours per day. In addition, the system can pulse an additional 50%, to 750 kW, for 10 minutes each hour, or 2-3 times capacity for seconds, providing additional capacity for motor starts or other events. These reductions in on-peak energy costs and demand charges will save an estimated $300,000 per year.

Moreover, additional savings can likely be achieved by avoiding so-called nuisance trips. The fuel cells require high power quality. Voltage drops or swells or other power quality problems can cause the fuel cells suddenly to power off or "trip". Although the fuel cells recover quickly and resume generating, the short-term loss results in a spike in electricity from SCE, increasing demand costs.

The PCS, which charges and discharges the battery while providing enhanced power quality and voltage support, is expected to help reduce or eliminate nuisance trips, saving another $100,000 annually.[3]

Gills will also benefit from the uninterruptible power supply (UPS) of the VRB®. Along with enhanced power quality and reliability, the VRB® will be able to operate in case of a power black-out. By also keeping the fuel cells online, the VRB® will be able to provide 1,200 kW of emergency power – which is extremely valuable to the operation and safety of the processing plant.

Prudent Energy Services Corporation, a wholly-owned subsidiary of Prudent Energy Corporation, will build, own and operate the VRB-ESS® in return for a share of the energy savings resulting from the project. Those energy savings are calculated as the avoided charges, costs and fees that would otherwise be paid by Gills to the local utility. Prudent has not disclosed the terms of this contract with Gills.

Advantages to the Grid

When not providing services to Gills, the VRB-ESS® can be available to support the efficient functioning of the electric grid. One of the unusual benefits of Prudent's flow battery technology is the ability to respond very quickly and supply energy for long periods of time. The California grid operator, known as CAISO (California Independent System Administrator), is responsible for the safety and reliability of the transmission system. The high penetration of intermittent renewable energy, like wind turbines and solar installations, has resulted in the need for fast responding energy sources to balance the rapid variability of generation.

[3] Prudent Energy's PCS has a sophisticated, fast acting, multi-quadrant, dynamic controller with proprietary control algorithms, and is capable of switching output across the full range of the device (i.e., from absorbing full power to exporting full power within cycles). The PCS also functions on a reactive power basis and in any combination of both real and reactive power requirements. The intelligence within the inverter is integrated into the overall control system. Therefore, the PCS is easily reprogrammed (on site or remotely) and adjusted for any changes in site requirements or settings required by the operator. The PCS is connected either in a series (isolated load) mode or in a shunt configuration with static transfer switch option for UPS functionality. With Prudent's PCS capable of delivering real power (watts) and/or imaginary power (volt-ampere reactive, or "VARs"), the system provides not only power smoothing but also ancillary services such as voltage regulation and VAR support. All Prudent power electronics undergo extremely rigorous testing before they are integrated into a complete installation.

Fast responding natural gas turbine "peaker" plants are currently used for this purpose. However, the VRB-ESS® can provide a faster, more accurate response – at low temperatures with virtually zero emissions. Recent studies have estimated that energy storage could reduce emissions from such services by 70%. CAISO has estimated the need for 2,000 MW of fast ramping storage, with at least 2 hours of energy, in order to integrate a 33% share of renewable energy into the total electricity production mix by 2020.[4]

In addition, high penetrations of solar photovoltaics (PV) are causing significant problems on many utility distribution circuits. In some cases, solar PV contributes over 50% or more of the energy at certain times of the day. This high penetration can create repeated and severe voltage variations due to moving cloud cover. Moreover, the fast ramps of generation in the morning and evening are an issue, plus the problem of thermal loading as circuits designed for one-way power sometimes experience over generation.

The VRB-ESS® can help integrate solar into the distribution circuit by acting as a shock absorber, rapidly responding to generation ramps, supporting voltage, supplying reactive power and avoiding thermal overload. CAISO and the electric utilities are currently designing programs and tariffs to utilize the unique benefits of energy storage.

Summary

Prudent's VRB® Energy Storage System will improve the efficiency of the existing Advanced Energy Recovery System on Gills' 14-acre property. The VRB-ESS® will also provide the Gills facility with emergency backup power and reduce the company's need to draw electricity from the grid when rates are highest. As a result, Gills Onions is expected to save hundreds of thousands of dollars each year in operating expenses.

"We are extremely pleased to host a VRB® system at Gills as an expansion of our Advanced Energy Recovery System," said Steve Gill, the company's President. "Energy storage has become an absolutely essential part of integrating renewables into the electricity grid reliably and efficiently, and Prudent Energy's system does this very well. Prudent has also shown it will stand behind its product and share the financial risk of putting these projects into the field, so their commercial and environmental benefits can be realized as quickly as possible."

[4] The KEMA "Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid" report can be found at: http://www.energy.ca.gov/research/new_reports.html

Jeff Pierson, Senior Vice President at Prudent Energy, indicated that Prudent will complete the Gills project by early 2012. "With our first megawatt-class VRB® project in California, we'll look toward similar projects in the US that will expand renewable energy facilities and reduce electricity costs," said Pierson.

About Prudent Energy

Prudent Energy is the designer, manufacturer, and integrator of the patented VRB Energy Storage System (VRB-ESS®) – a large-capacity, long life, clean energy storage system. With its US headquarters in the Washington, DC area, Prudent is deploying energy storage solutions for both kW-Class and MW-Class power applications throughout the world. Unlike other advanced battery systems, Prudent's VRB® systems operate at low pressure and room temperature, with an energy-holding electrolyte that never wears out. In addition, customers only buy the capacity they need and can easily add energy and power in modular fashion, making the VRB-ESS® an ideal choice for renewable energy integration and smart grids. www.pdenergy.com

About Gills Onions, LLC

Founded in 1983, Gills Onions is one of the nation's largest, family-owned onion growers and operates one of the largest, most sustainable fresh-cut onion processing plants in the world. In concert with sister company Rio Farms, the Gill brothers manage over 15,000 acres of farmland and 300,000 square feet of processing and warehouse facilities. Gills Onions is committed to continuous process improvement to positively impact the air, land, water, energy, and communities they rely upon for their livelihood. www.gillsonions.com

Storage for a sustainable future

Prudent Energy
VRB® Systems

The Leading Clean Energy Storage Company

www.pdenergy.com

Corporate Profile

Company Overview

Prudent Energy designs, manufactures and installs the patented Vanadium Redox Battery Energy Storage System (VRB-ESS®) - an advanced "flow battery" that delivers reliable, high performance, large scale electrical energy storage. Prudent Energy's VRB® can precisely align electricity supply and demand, generating or absorbing from several kilowatts up to many mega-watts of power within milliseconds. This allows utilities to balance loads, make better use of existing infrastructure and regulate voltage and frequency. Installed at commercial and industrial facilities, the VRB-ESS® reduces operating expenses while improving power quality and providing reliable backup power.

The VRB-ESS® operates at room temperature and provides years of reliable, low–maintenance operation regardless of operating conditions or the number of times the system is charged and discharged. In addition, the system's modular design means customers can buy or lease a system whose power output and energy storage exactly fit their needs. This flexibility makes the VRB-ESS® an ideal choice for renewable energy integration, remote area power supply and smart grids.

Corporate Offices

KW-Class VRB-ESS®

Prudent Energy's patented kW-class VRB Energy Storage System (VRB KW-ESS®) is an advanced flow battery which provides reliable, high–performance energy storage.
Incorporating the VRB-ESS® into a local energy management system yields immediate cost benefits to isolated communities, remote telecommunications site operators, or in any system powered primarily by wind, solar or diesel-fuelled sources.

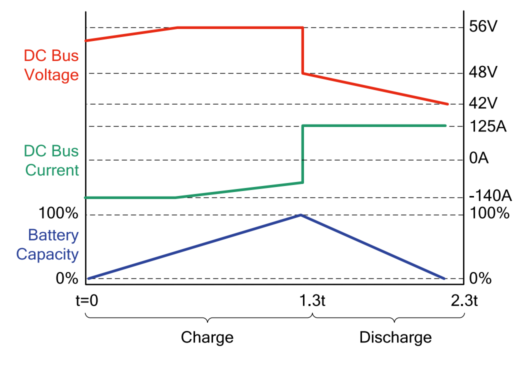
KW-Class Characteristics

Performance Characteristics

Nominal voltage	48 VDC
Open circuit voltage range	47 VDC to 54 VDC
Maximum charge voltage	56 VDC
Minimum voltage on discharge	42 VDC
Maximum charge current	140 ADC
Maximum discharge current, continuous	125 ADC
Peak discharge current, <300s	175 ADC
Continuous output power, top of charge state	6.0 kW
Continuous output power, bottom of charge state	5.2 kW
Duty cycle	Continuous
Interface	RS485 / 0-10 VDC

Physical Characteristics

Power Module only	510 kg / 1,100 lb	1.2m x 1.0m x 1.1m / 48" x 40" x 43"
20kWh kW-Class VRB-ESS®	3,000 kg / 6,600 lb	3.8m x 1.4m x 1.3m / 150" x 55" x 47"
40kWh kW-Class VRB-ESS®	5,300 kg / 11,600 lb	3.8m x 1.4m x 1.9m / 150" x 55" x 75"
Containerized 20kWh kW-Class VRB-ESS®	5,200 kg / 11,400 lb	3.7m x 2.2m x 2.2m / 146" x 87" x 87"



Operating Characteristics


kW-class Power Module


Containerized System

Storage for a sustainable future

Prudent Energy

The Leading Clean Energy Storage Company

MW-Class VRB-ESS®

VRB-ESS® Technology

Prudent Energy's patented MW-Class VRB Energy Storage System (VRB MW-ESS®) is being deployed on a utility scale to support the integration of renewable energy sources and to improve the stability, power quality and economics of the modern smart grid. Prudent Energy's standard VRB-ESS® module is rated at 200 kW; multi-megawatt arrays of these modules, combined with electrolyte storage tanks, can be combined to exactly suit the power output and energy capacity needed at a given site. Prudent Energy's VRB-ESS® provides unparalleled performance, featuring:

- Unlimited daily cycling 100% DOD
- Lowest total cost of ownership since electrolyte never "wears" out
- Can set operating state of charge for wind power smoothing
- Accurate, real-time capacity measurement
- Individually customized power and energy storage capability
- High availability, low operation and maintenance cost
- Up to 7 years warranty

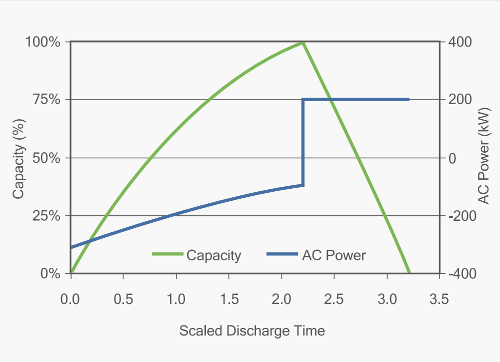
MW-Class Characteristics

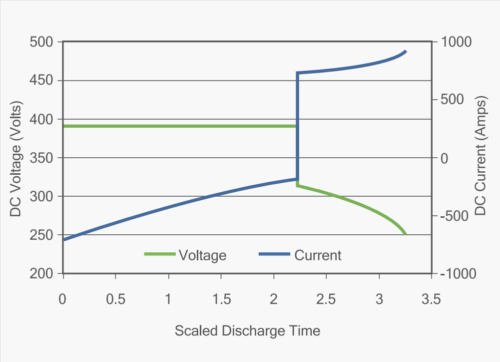
Performance Characteristics

Rated Power Output, AC	200 kW
Peak Power Output, AC (SOC > 50%)	263 kW (130%) for 10 min every hour non consecutively
Typical Voltage Output	400/480 VAC
Frequency Output	50/60 Hz
Step response (Charge to Discharge)	<50 ms

Physical Characteristics

Module dimensions	m (ft)	9.3 x 2.0 x 2.8 (30.5 x 6.6 x 9.3)
Module weight, dry	kg (lb)	13900 (30644)
Electrolyte required per hour of rated discharge	m^3	15.4



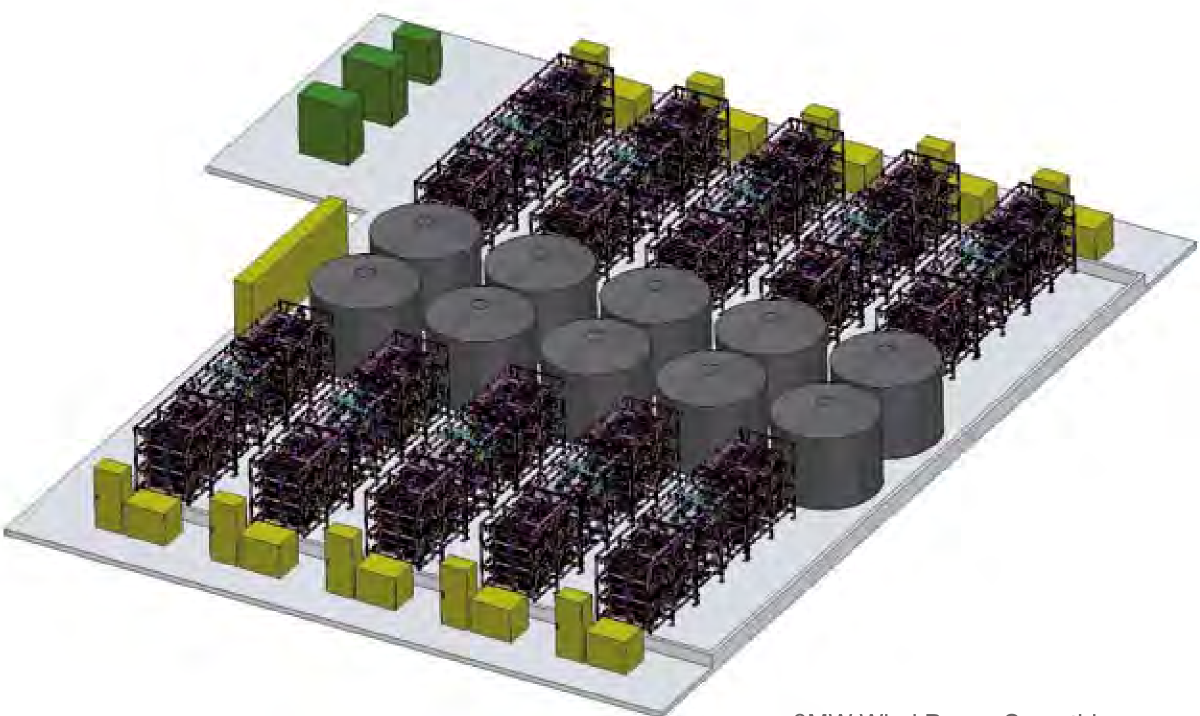


Flexible and Scalable Systems

Prudent Energy's VRB-ESS® is fully scalable and flexible. The system's power capacity is determined by the number of power modules installed, while the system's energy capacity is determined by the volume of electrolyte contained in its storage tanks. Adding modules gives more power handling capacity; adding tanks gives more hours of energy storage. The result is a system engineered to precisely fit customers' requirements, so they never buy more capacity than they need.

This flexibility, combined with the lowest cost of ownership of any grid-scale, advanced flow battery storage system and the ability to continuously charge and discharge the system to its full rated capacity ensures VRB-ESS® operators earn exceptional economic benefits over the system's entire service life.

VRB–ESS® components, including specialty materials developed by Prudent Energy, are constructed entirely from widely-available commodities. The proprietary electrolyte is based on the element vanadium, which is abundantly available from both primary extraction and industrial waste reprocessing.



3MW Wind Power Smoothing

System Control

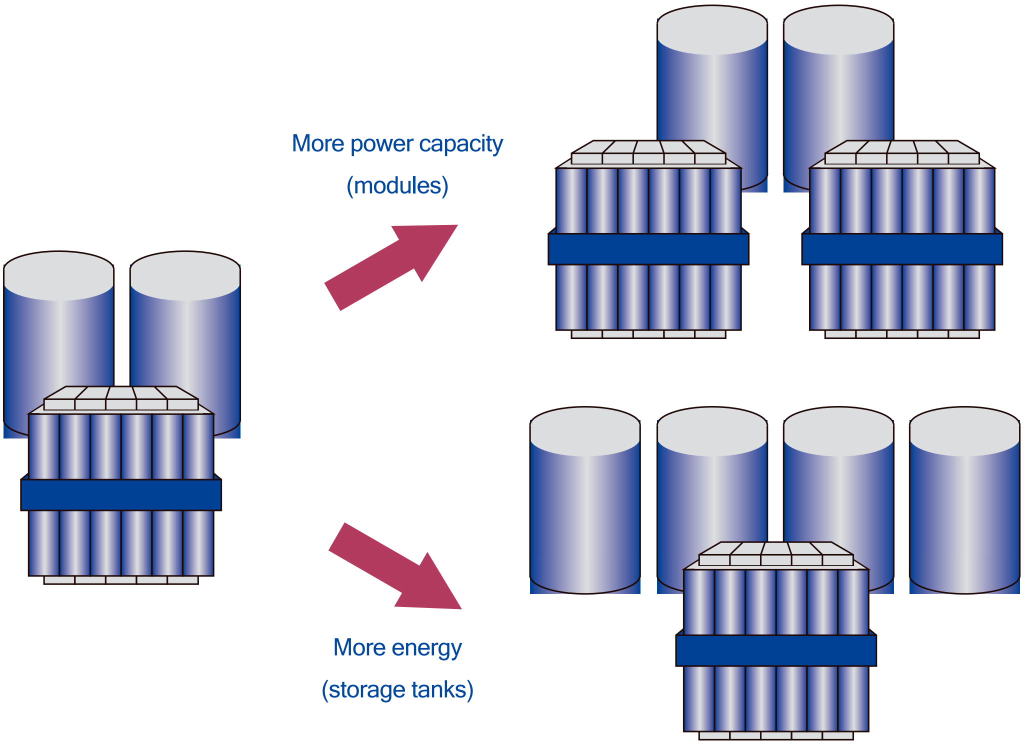
Prudent Energy's control system and PCS ensure that the VRB-ESS® is seamlessly integrated into operators' existing infrastructure, adapting to those operator's needs to provide the greatest possible value at a particular site.

Power Conversion System (PCS)

Prudent Energy's Power Conversion System (PCS) converts between the grid's AC current and the DC current that flows to and from the VRB-ESS®, allowing the system to charge and discharge. The PCS's ability to simultaneously manage both real and reactive power means the VRB-ESS® can provide both bulk energy storage and ancillary services: using proprietary control algorithms, the PCS can provide enhanced power quality, voltage support and frequency control to the local grid.

Control System

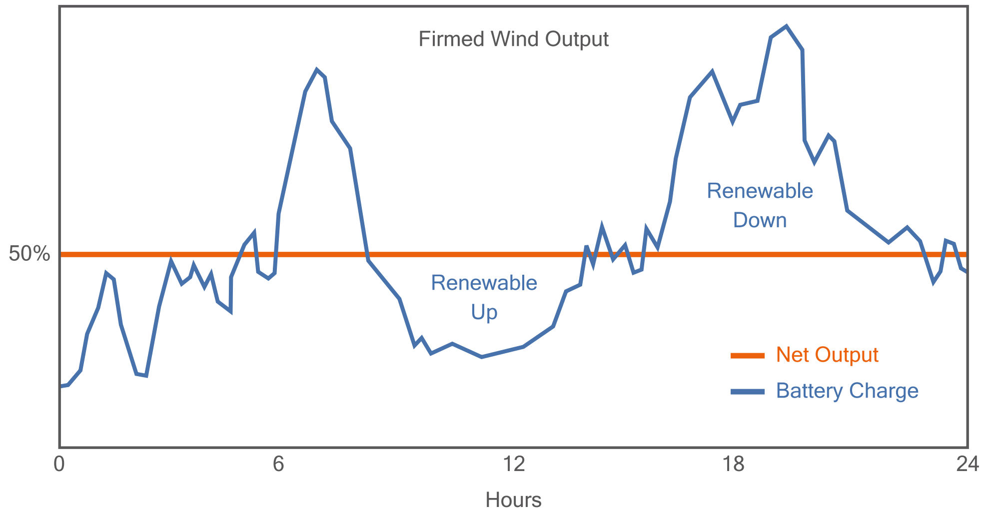
The control system allows the operator to effectively manage operation of the VRB–ESS®, optimizing performance according to individual site characteristics. The control system allows the operator to control the time and rate of charge and discharge, while simultaneously managing parameters for the provision of ancillary services. Some standard communication interfaces are provided for customer option including Modbus TCP/IP, Modbus RTU and Profibus. The system also provides customized reporting and alarm functions.



Applications

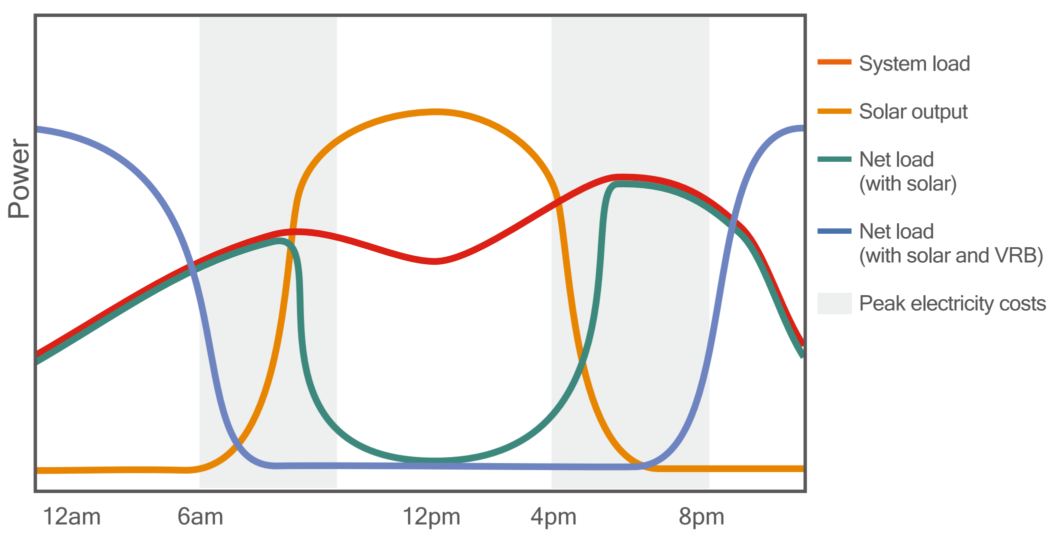
Renewables smoothing

When installed along with a renewable energy source, the VRB-ESS® can make those sources' intermittent energy flow both stable and dispatchable. For users, this means a decreased dependence on electricity purchased from the grid and a higher overall renewable source utilization; for generators and utilities, the VRB-ESS® increases renewables' reliability and economics.



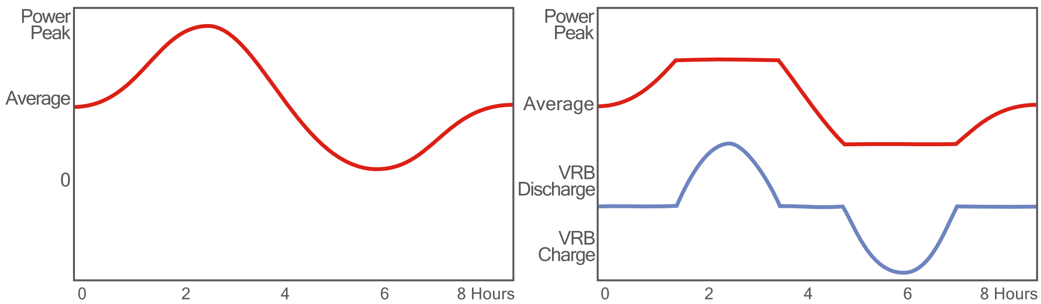
Energy time-shifting

The VRB-ESS® has the capability to store and discharge electricity at full rated power over many hours. This allows electricity users, particularly those with large solar generating capacity, to shift their energy consumption away from times with high demand charges, while allowing utilities to improve their overall system performance at peak times.



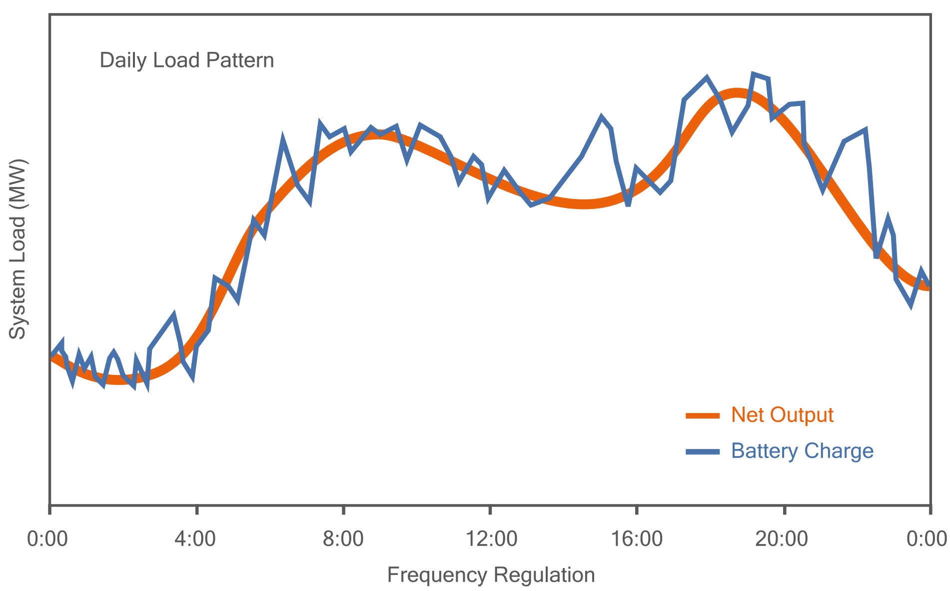
Peak power capacity and congestion management

Prudent Energy's VRB-ESS® can reduce congestion constraints both within the electric power grid and on users' sites. For utilities, this means that capacity investments can be deferred by making more efficient use of existing infrastructure. Users who are assessed both demand and capacity charges can benefit by shaving the peaks from their daily consumption, offering significant capacity charge savings.



Power quality management

Prudent Energy's systems can provide voltage compensation, reactive power management, frequency regulation and local area backup power services. For utilities this means extracting more value from existing assets; grid services providers can take advantage of ancillary services markets; and facility operators can ensure their facilities get only high quality, uninterruptible power.



State Grid Project, China

State Grid Project, China

Project Reference

VRB-ESS systems have been in commercial service for over fifteen years. Between 1996 and 2004 over seven megawatts of VRB-ESS capacity was installed in Japan. Since 2004, Prudent Energy has installed over 50 VRB-ESSs at sites around the world.

Prudent Energy's quality and environmental management systems are ISO 9000 (2008) and ISO 14000 (2004) certified.

Storage for a sustainable future

Prudent Energy

The Leading Clean Energy Storage Company

Prudent Energy
VRB® Systems

Prudent Energy Corporation
7200 Wisconsin Avenue
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Bethesda, MD 20814 USA
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Fax:+1 301 825 8914

sales@pdenergy.com
www.pdenergy.com

APPENDIX D – COMPRESSED AIR ENERGY STORAGE DATA

RWE Power

ADELE – ADIABATIC COMPRESSED-AIR ENERGY STORAGE FOR ELECTRICITY SUPPLY

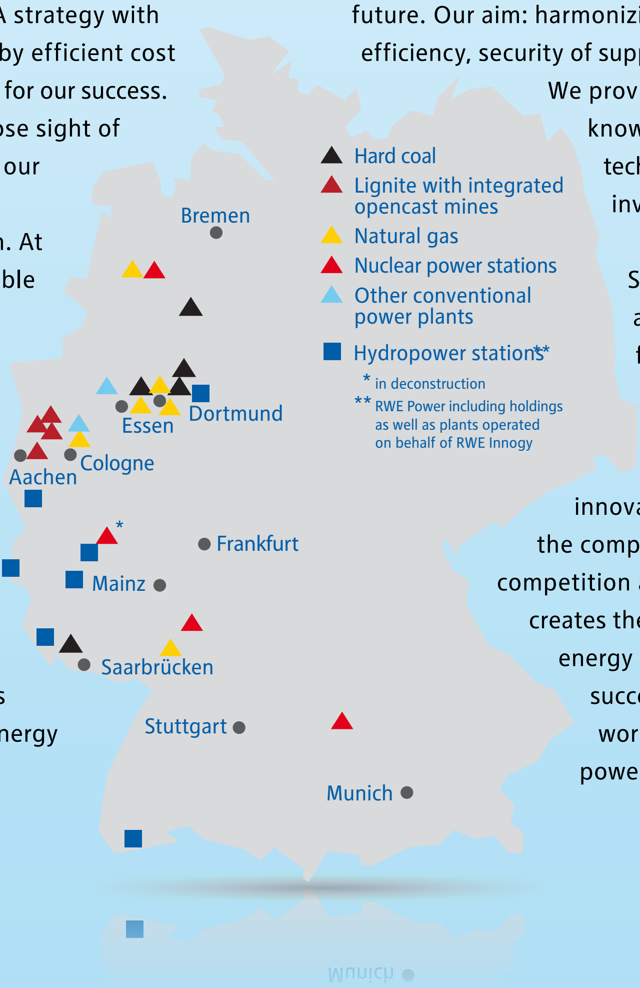
RWE
The energy to lead

RWE POWER – ALL THE POWER

RWE Power is Germany's biggest power producer and a leading player in the extraction of energy raw materials. Our core business consists of low-cost, environmentally sound, safe and reliable generation of electricity and heat as well as fossil fuel extraction

In our business, we rely on a diversified primary energy mix of lignite and hard coal, nuclear power, gas and hydropower to produce electricity in the base, intermediate and peak load ranges.

RWE Power operates in a market characterized by fierce competition. Our aim is to remain a leading national power producer and expand our international position, making a crucial contribution toward shaping future energy supplies. A strategy with this focus, underpinned by efficient cost management, is essential for our success. All the same, we never lose sight of one important aspect of our corporate philosophy: environmental protection. At RWE Power, the responsible use of nature and its resources is more than mere lip service. Our healthy financial base, plus the competent and committed support of some 17,800 employees under the umbrella of RWE Power enable us to systematically exploit the opportunities offered by a liberalized energy market.



In this respect, our business activities are embedded in a corporate culture that is marked by team spirit and by internal and external transparency. With an about 30 per cent share in electricity generation, we are no. 1 in Germany, and no. 3 in Europe, with a 9 per cent share. We wish to retain this position in future as well. And that is where we want to stay. Which is why we are investing our own energy in shaping and designing the energy supply of the future. Our aim: harmonizing the claims of economic efficiency, security of supply and climate protection. We provide impetus – with our know-how, innovative technologies and considerable investment.

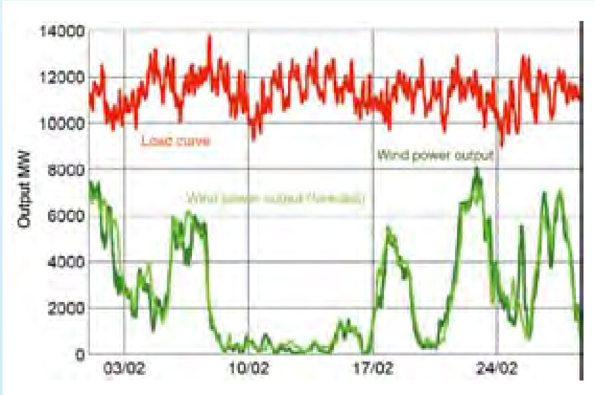
So research and development are of strategic importance for us. Our scientists and engineers are pursuing visions, tapping potentials, implementing ideas. This innovative power strengthens the company in the face of growing competition and on the way ahead. It creates the preconditions for a secure energy supply and economic success. That is what we are working for – with all our power.

COMPRESSED-AIR ENERGY STORAGE (CAES) AS BUFFER FOR ELECTRICITY FROM WIND AND SUN

The demand for flexible balancing power to maintain grid stability shows strong growth.

By 2020, the share of renewable energy in Germany's power generation is set to rise from today's 15% or so to 30%. The biggest slice of the new-builds required – besides biomass – will be accounted for by wind power and photovoltaics: the renewal of turbines onshore alone and extensions offshore will double the installed capacity of wind power to nearly 50,000 megawatts (MW). The feed-in of wind and solar power is weather-dependent, however, and is extremely intermittent – as experience has shown – between zero and 85% of the max. installed capacity. So if the electricity grid is to remain stable, these fluctuations must be balanced. This is because the amount fed in and the amount consumed must be the same at all times. Today, flexibly deployable, conventional power plants are used for this, as a rule pumped-storage, natural-gas and hard-coal power stations.

In certain weather conditions, their capacities are already nearly exhausted today. Moreover, thanks to the growing share of combined heat and power generation (CHP), they will tend to decline rather than increase. Still, CHP plants, too, are not geared to the electricity demand; their operation follows the demand for heat. Upshot: the need for flexible power-plant capacity, i.e. for amounts of electricity available in the short term, is growing rapidly.



Power consumption and power generation from wind in the VET grid zone (February 2008) (source: VDE study)

This is where storage technology comes in: whenever supply exceeds demand, e.g. on a windy day, the power can be stored and then fed into the grid again during a calm. If this succeeds on a large scale, the interaction of conventional power plants with renewable resources can be optimized. Storage technologies will not be a panacea, but could gain considerably in importance on tomorrow's electricity market.

ELECTRICITY STORAGE TODAY: PROVEN TECHNOLOGY, NEW APPROACHES

The technology of choice today is the pumped-storage power plant. In any excess power supply, water is electrically pumped into a reservoir on a hill, so that it can be discharged when power demand is high to drive a turbine in the valley.

Efficiency is between 75 and 85%. Today, Germany has pumped-storage power plants producing a total of about 7,000 MW. The expansion potential is severely limited, especially in northern Germany where the balancing need is greatest.

Compressed-air energy storage (CAES) is similar in its principle: during the phases of excess availability, electrically driven compressors compress air in a cavern to some 70 bar. For discharge of the stored energy, the air is conducted via an air turbine, which drives a generator.

Just as in pumped storage, its power can be released very quickly. One merit over pumped storage, however, is that the visible impact on the landscape is low. What is more, the facilities can be built near the centres of wind-power production, especially in central and northern Germany. Today, there are two CAES plants: one in Huntorf (Lower Saxony) since 1978, and another in McIntosh (Alabama, USA) since 1991. The efficiency of the 320-MW plant in Huntorf is about 42%, that of McIntosh around 54%. This means that they are more than 20 percentage points below the efficiency of pumped-storage plants.

What lowers the efficiency: first, the air that he ats up during compression must be cooled down again to the ambient temperature before it can be stored in the cavern. Second, the cold air must be re-heated for discharge of the storage facility since it cools strongly when expanding in a turbine for power generation. Today's plants use natural gas for this. Valuable efficiency percentages are lost.

Physical background: when air is compressed, heat, too, is produced, besides pressure. This can be observed when using a bicycle pump, for instance. Conversely, cold emerges when compressed gas escapes and loses pressure. This can be felt, e.g., when refilling a gas lighter.

Herdecke pumped-storage power plant

Turbine hall of the Vianden pumped-storage power plant

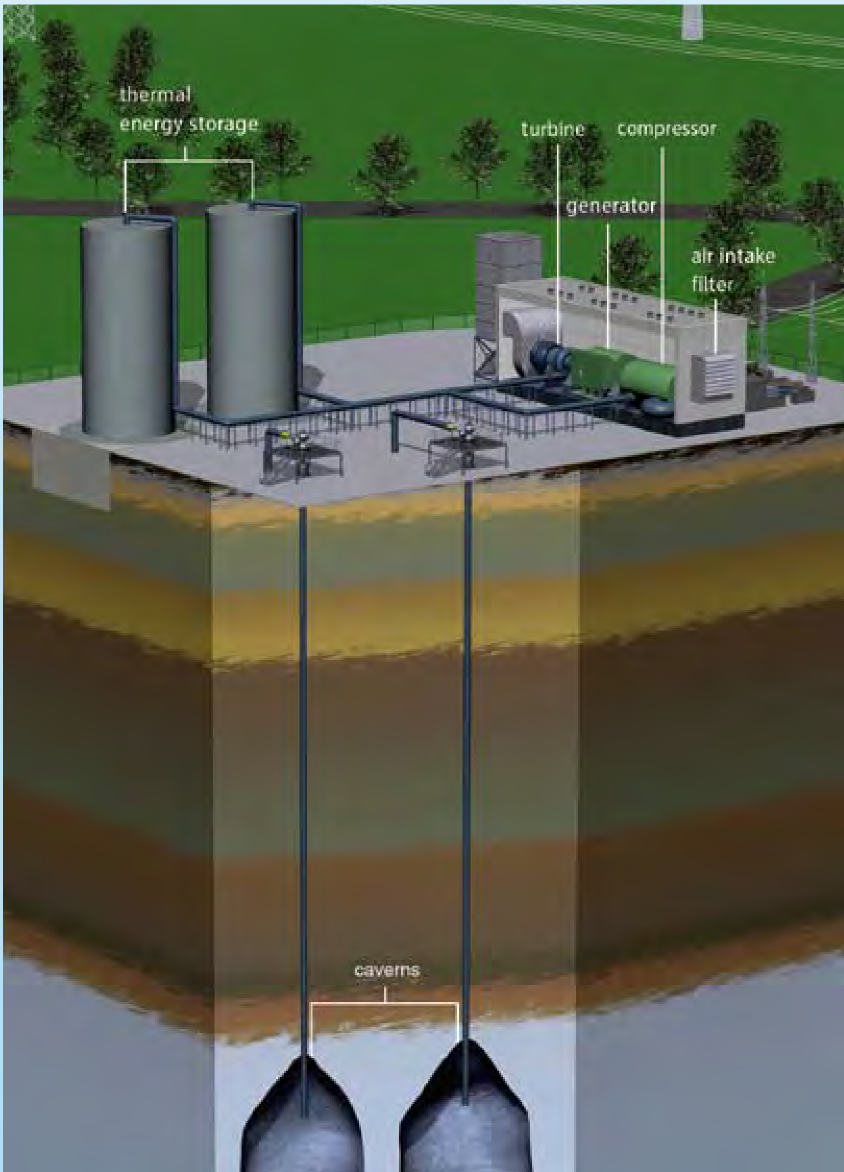
ADIABATIC COMPRESSED-AIR ENERGY STORAGE WITH BETTER EFFICIENCY

RWE Power is working along with partners on the adiabatic compressed-air energy storage (CAES) project for electricity supply (ADELE). „Adiabatic“ here means: additional use of the compression heat to increase efficiency.

RWE Power is working along with partners on the adiabatic compressed-air energy storage (CAES) project for electricity supply (ADELE). „Adiabatic“ here means: additional use of the compression heat to increase efficiency.

When the air is compressed, the heat is not released into the surroundings: most of it is captured in a heat-storage facility. During discharge, the heat-storage device rereleases its energy into the compressed air, so that no gas co-combustion to heat the compressed air is needed. The object is to make efficiencies of around 70% possible. What is more, the input of fossil fuels is avoided. Hence, this technology permits the CO2-neutral provision of peak-load electricity from renewable energy. That this technology is doable has been shown by the EU project Advanced Adiabatic Compressed Air Energy Storage (AA-CAES) and by a study presented by General Electric and RWE in 2008.

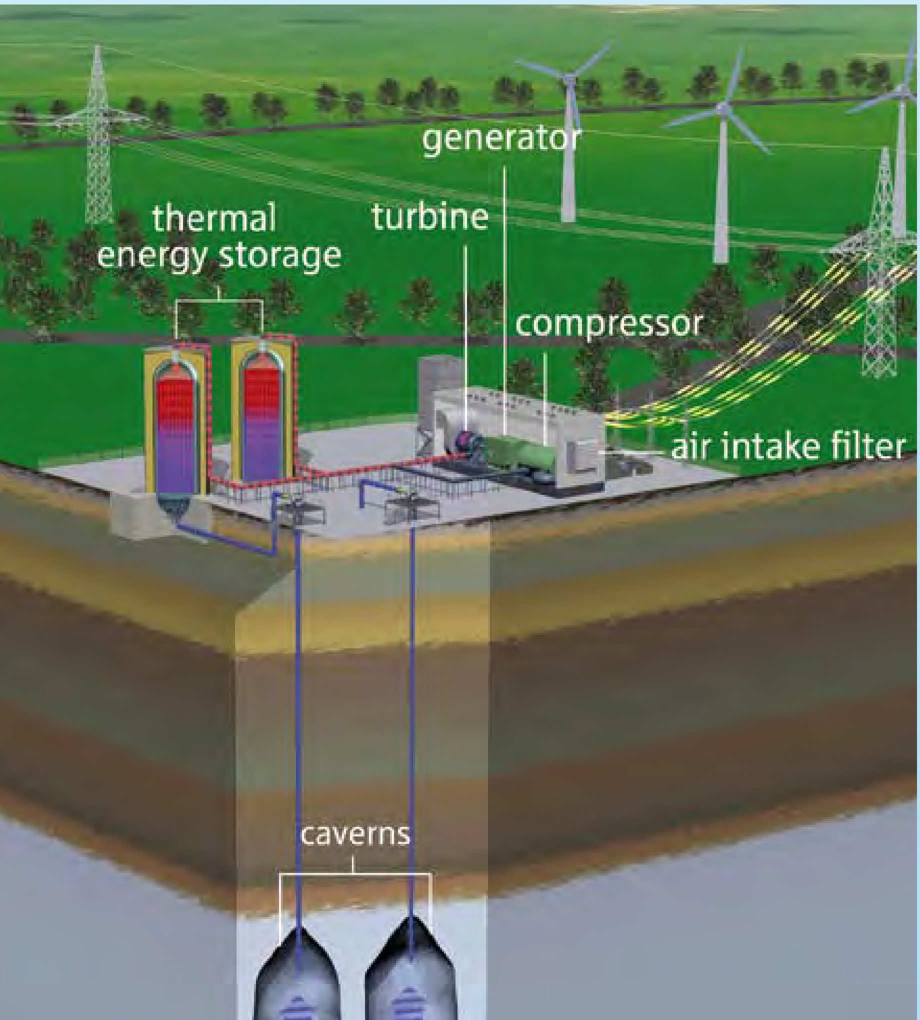
The aim of the new joint project mounted by the German Aerospace Center (DLR), Ed. Züblin AG, Erdgasspeicher Kalle GmbH, GE Global Research, Ooms-Ittner-Hof GmbH and RWE Power AG – the project being officially sealed in January 2010 – is to develop an adiabatic CAES power station up to bidding maturity for a first demonstration plant. The federal ministry for economics has held out a prospect of funding for the ADELE project.



UNRIVALLED WORLDWIDE

Pioneering work: six partners from industry and research want to bring adiabatic CAES technology up to industrial-scale application maturity.

In day-to-day charging and discharging operations, a commercial plant should store some 1,000 MW hours of electrical energy and feed some 300 MWel into the grid for several hours. The demonstration plant, which is necessary as a preliminary stage in the development line and is, in the nature of things, smaller, could probably go on stream in 2016 at the earliest. ADELE is bundling the know-how and experience of a power-plant operator, the manufacturing industry and research in an effort to clarify the open issues of the technology.



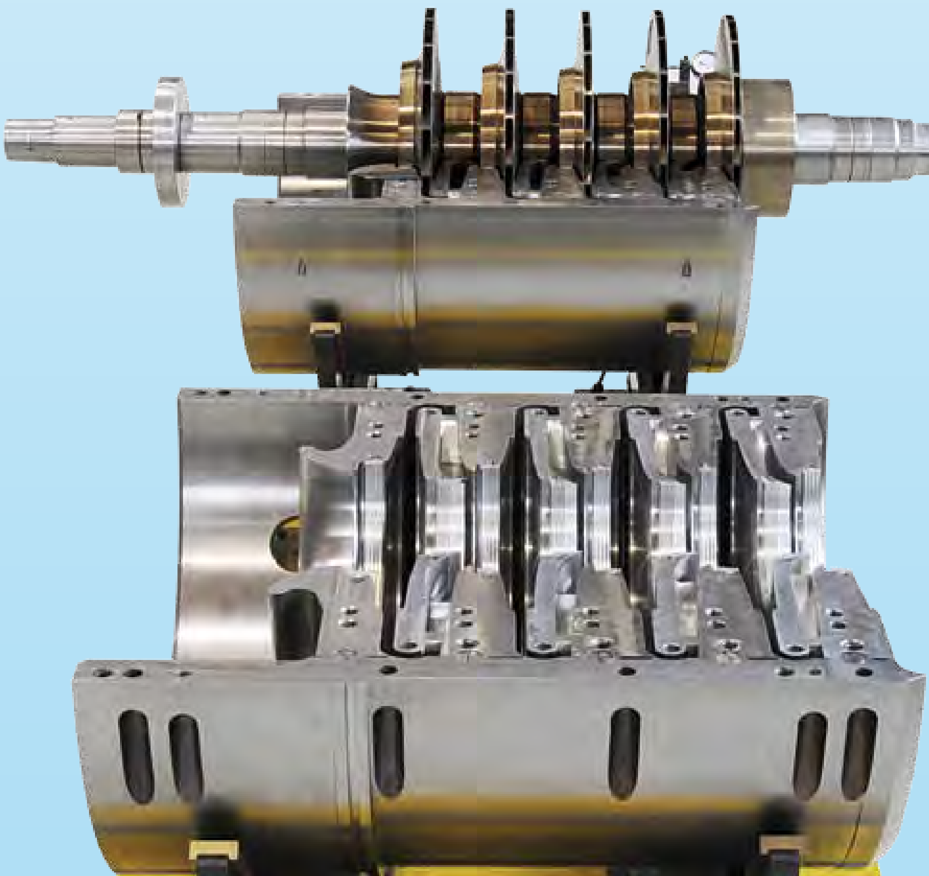
RWE Power is coordinating the project. As future operator, it is drawing up the requirement profile. This comprises, among other things, the deployment strategy, availability and operating safety issues. Investigations are assuming day-cycle-based operations geared to the spot market with proportionate provision of balancing energy. The vetting of feasible locations, too, is on RWE Power's work schedule.

The optimal interplay of all technical components, i.e. the system design, is the project's core task. Under the lead management of GE Global Research in Garching, specialists are clarifying the overriding mechanical-engineering and thermodynamic issues and working out the best-possible configuration for compressor, turbine, heat-storage device, cavern and other units. The final result will be a concept ready for bidding that covers the entire plant.

TECHNICAL CHALLENGES OF STORAGE: COMPRESSOR AND HEAT-STORAGE

The ADELE concept places extremely heavy demands on the equipment used: cyclical stresses, temperatures of over 600°C and a pressure of up to 100 bar.

General Electric (GE) is developing the compressor, one of ADELE's core components: driven by an electric motor, the compressor sucks up the ambient air, which is then compressed to up to 100 bar and fed into the heat-storage device as hot compressed air. Nothing is known of the interaction of high pressure and high temperatures at the compressor outlet in relevant industrial-scale requirements. GE must find innovative solutions for the entire compressor train, taking account of the cyclical mode of operation while meeting the demand for part-load capability and still-high efficiencies. GE is producing a preliminary aerodynamic design and the preliminary mechanical compressor design. Details will be clarified in a development project running in parallel with ADELE and financed by RWE and GE Oil & Gas. The heat of the compressed air – over 600°C – is no waste heat in the ADELE concept. It is stored and, during later discharge, re-used to pre-heat the compressed air. The heat-storage facilities are up to 40-m-high containers with beds of stones or ceramic moulded bricks through which the hot air flows. Which type of heat-storage stone holds on to the heat best and releases it again quickly when required? How must a heat-storage facility be insulated? Which building materials keep the pressure vessel tight? What must the pipelines to and inside the pressure vessel look like? Numerous material, structural and process-technology issues are on the agenda of the project partners Ed. Züblin AG and its subsidiary Ooms-Ittner-Hof GmbH (OIH), and of the German Aerospace Center (DLR).



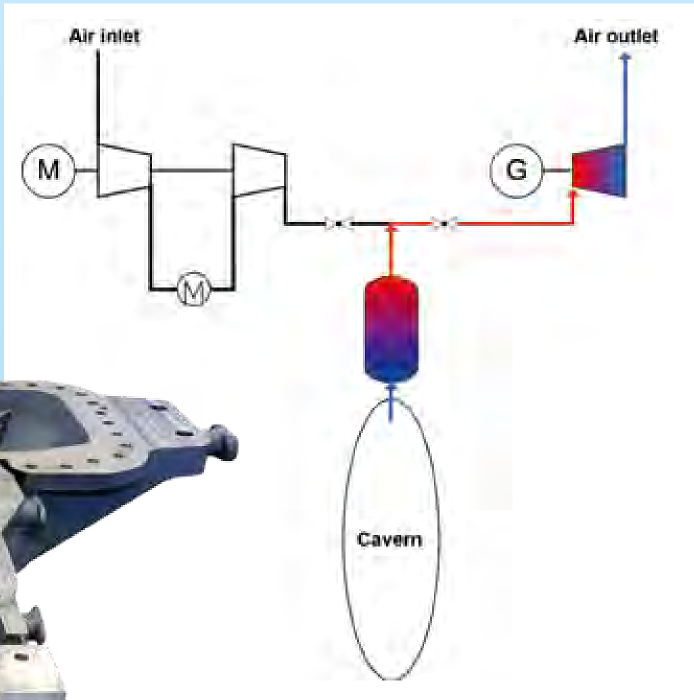
TECHNICAL CHALLENGES OF DISCHARGE: TURBINE AND CAVERN

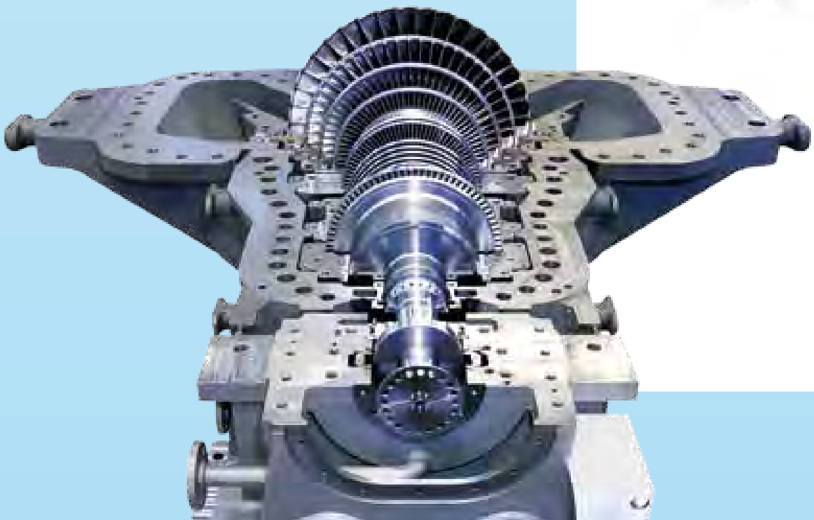
Turbine technology and cavern engineering are being adapted to meet the special requirements of the adiabatic CAES power plant.

Erdgasspeicher Kalle GmbH, a company in the RWE Group, has great experience in the planning, building and operating of underground natural-gas storage facilities. In ADELE's case, however, storing compressed air in a subterranean salt cavern is different from storing natural gas: the air is stored and removed on a daily basis and not over the long term, and the pressure fluctuates accordingly. This has consequences for the size and design of possible caverns. In addition, the humidity can lead to more corrosion of the underground bore-hole equipment, the cavern heads, pipes and fittings. Geology and locational issues, too, must be clarified.

The air turbine is the subject of another GE working package: at a later date, compressed air will flow into this central ADELE component to set it rotating and drive the connected generator. Here, General Electric's engineers are checking how they can adapt existing turbine technology for use in the CAES plant. The pressures to be expected, for example, far exceed the inlet pressures of today's gas turbines. Moreover, the turbine must cope with the considerable fluctuations in pressures and throughput amounts when the storage facility is discharged.

The turbine is the last link in the charging/discharging chain, so that the aimed-at overall efficiency of some 70% should approximate that of pumped-storage plants for the first time. ADELE would thus provide convincing answers to the questions: where to put the electricity when it does not happen to be needed? Who helps the powering-up peak-load stations to guarantee grid stability if electricity feed-in from wind and sun collapses?



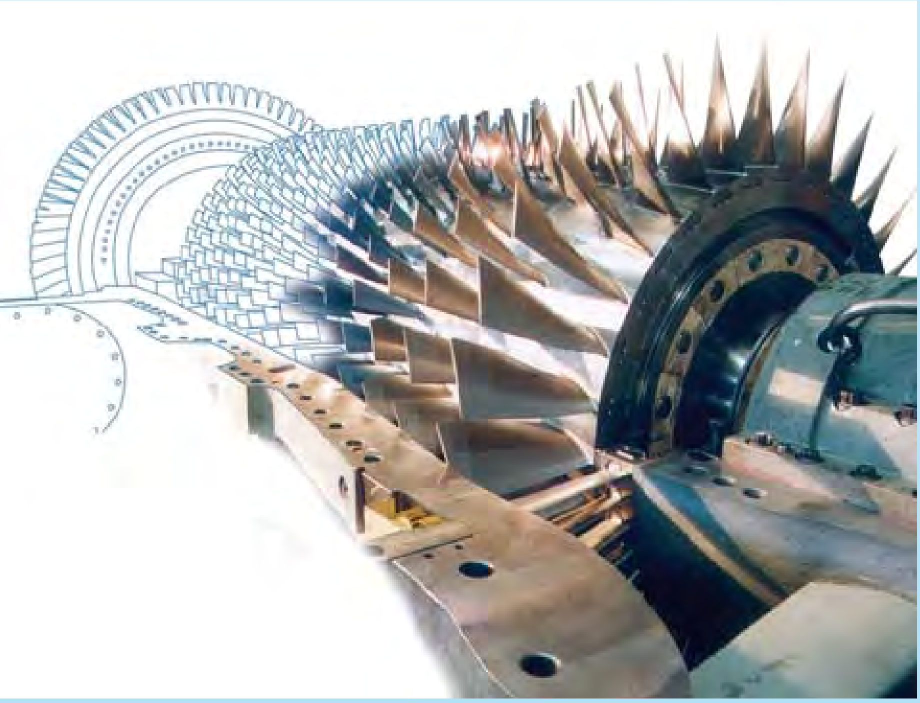


GE – FOCUS ON COMPRESSOR, TURBINE, OVERALL INTEGRATED PLANT

GE imagination at work

From its experience in developing and operating sophisticated energy systems and turbo machinery, GE is inputting comprehensive know-how for system optimization and for compressor and turbine development.

GE Global Research was opened in Garching near Munich in 2004 as the GE group's European research centre. Research focuses are the future energy supply using renewable and environmentally compatible energy concepts as well as increased efficiencies in power plants and turbo machinery. After extensive preliminary work, GE – in the ADELE project and in another parallel project financed by RWE and GE Oil & Gas – will drive forward the development of the CAES technology with focuses on system optimization and on compressor and turbine development. This requires a high degree of integration of all system components. From an application angle, therefore, the technical-economic optimization of the overall system is a key task which must take place in an iterative form with the development of the components. Besides system optimization, the success of the overall concept will depend crucially on an efficient and low-cost air compressor. The high temperatures and pressures at its outlet – coupled with cyclical stress – are a special technical challenge for which no commercial solutions are available as yet. Which is why ADELE needs innovative approaches in the design of the compressor train involved and the deployment of sophisticated manufacturing processes.

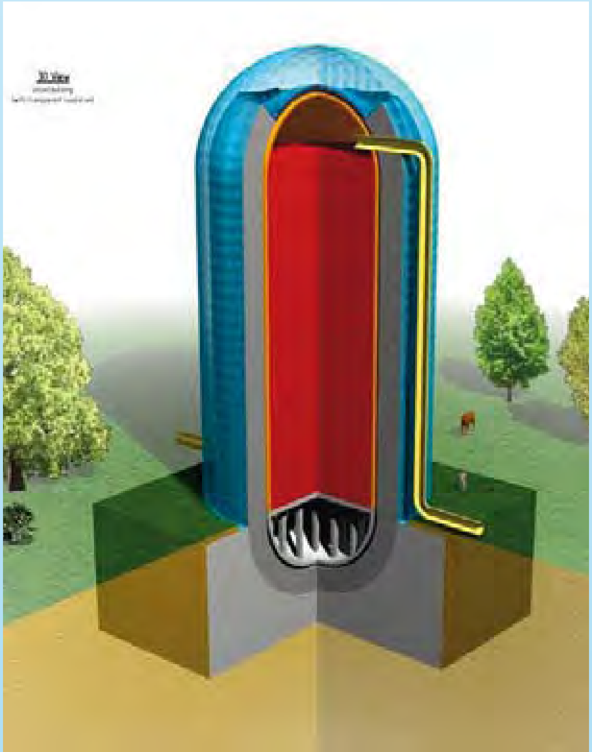


To obtain high overall efficiencies, a suitable air turbine, too, is necessary. Here, existing technology must be adapted especially to the high and temporally varying turbine inlet pressures and volume flows of a CAES plant. GE Global Research and GE Oil & Gas are in charge of developing the core components ‚air compressor' and ‚air turbine'.

ZÜBLIN AND OOMS-ITTNER-HOF - FOCUS ON HEAT STORAGE

Heat-storage devices, storage material and high-temperature insulation are the working focuses of Central Technology at Ed. Züblin AG and its subsidiary Ooms-Ittner-Hof GmbH.

Ed. Züblin AG is no. 1 in German building construction and civil engineering. At its heart is Central Technology, which bundles its technical competencies. One focus of its work is energy storage, a field in which its engineers have already acquired extensive know-how and numerous patents for solar power stations. For ADELE, they are in charge of developing the heat-storage pressure vessel. To be able to charge and discharge the large amount of heat at the high temperature of over 600°C with low exergy losses, the heat flows through the heat-storage device directly and is stored in inventory stones. Due to the high pressure, it is necessary to develop a pressure-resistant storage vessel specially adapted to the process requirements, and to integrate the sub-components ‚high-temperature insulation' and ‚storage inventory' to be developed by the project partners Ooms-Ittner-Hof and DLR. The cyclical temperature and pressure stresses and the aimed-at permanence and dependability of the heat-storage device place heavy demands on engineering and require innovative solutions and materials. Ooms-Ittner-Hof is one of the top performers in refractory and chimney construction and handles jobs in both engineering and assembly worldwide. The company has a 150-year tradition in refractory and chimney construction for industrial plants, like power stations, refineries, glassworks and steel mills. Refractory construction uses tried-and-tested materials that have been further developed across the decades. ADELE poses new challenges for the experts with its boundary conditions of cyclical temperatures, humidity, high pressure and long service lives. For one thing, this requires extensive material tests. Also needed are heat-technology calculations, constructional designs of ceiling and wall elements, anchorage points, assembly concepts, manufacturing and field assembly activity charts, and the dimensioning of the storage stones.



DLR – FOCUS ON HEAT-STORAGE DEVICE

Deutsches Zentrum für Luft- und Raumfahrt e.V. in der Helmholtz-Gemeinschaft

The German Aerospace Center (DLR) has years of experience in adiabatic CAES power plants.

DLR's Institute of Technical Thermodynamics (ITT) in Stuttgart is working on the use of highly efficient energy-conversion technologies and technical solutions for the introduction of renewable energy sources. The spectrum of its work ranges from basic-research-oriented laboratory activities all the way to the operation of pilot plants.

One of the focuses of its work is high-temperature heat storage for power-plant engineering and industrial processes for which it has long years of experience and in-depth involvement in numerous national and European development projects.

Here, adiabatic CAES has been the institute's field of activity for several years now: as early as 2003, initial concepts for the build-up of a high-temperature storage facility for this power-plant type were worked out and assessed together with partners in Europe's four-year „AA-CAES" project. Further-going contributions were made in a later study commissioned by RWE.

In the federal economics ministry's ADELE project, the state of knowledge on the heat-storage device is being further developed up to demonstration maturity in a division of labour between the partners Ed. Züblin and OIH. The focuses of DLR's contributions are on the concept and on design issues for shaping the storage inventory and the high-temperature insulation which, as core components, crucially mark the performance and cost efficiency of the overall structure.

The work is being supplemented by experimental investigations: functional tests on storage-facility components, for example, are underpinning the designs. For this purpose, existing DLR process-development units are being used. Cyclical testing of materials will answer existing questions on the choice of materials.

Test rig to investigate high-temperature storage facilities at DLR Stuttgart

RWE Power AG
Essen/Köln
www.rwe.com/rwepower

Position: Januar 2010 ▪ Design: Spohr's Büro für Kommunikation GmbH, Cologne

DRESSER-RAND

Bringing energy and the environment into harmony.℠

COMPRESSED AIR ENERGY STORAGE (CAES)


Unique load management and generation "on demand"

Unmatched experience makes Dresser-Rand your partner of choice.

This CAES equipment built by Dresser-Rand has been performing reliably in McIntosh, Alabama since 1991.

FROM CAES PIONEER TO CAES LEADER

Dresser-Rand is uniquely qualified to deliver total demand management and power generation using Compressed Air Energy Storage (CAES) solutions. We designed and supplied the entire turbomachinery train and controls for the first CAES plant in North America. Only the second of its type in the world, Power South's McIntosh, Alabama, USA facility has been building an impressive record of starting reliably more than 90 percent of the time, and demonstrating greater than 95 percent reliable operation since 1991.

FLEXIBLE SOLUTIONS FROM A SINGLE SOURCE

Dresser-Rand can supply the entire CAES train. Our teamwork reduces your project management time, and single-source packaging minimizes transaction and transportation costs.

We custom-engineer each CAES train to provide you with a system designed specifically to meet your site's operating and geologic requirements. We select and fine-tune standard Dresser-Rand components for your project, then we make sure that all components will work together to maximize efficiency, and reduce installation and start-up times. Systems can be configured for salt caverns, hard-rock caverns, aquifers, or depleted natural gas fields on land or sea.

FUTURE OPPORTUNITIES FOR CAES SOLUTIONS

Ever alert to workable solutions, Dresser-Rand engineers recently secured a patent for a sub-sea CAES concept that combines a conventional CAES facility with a sub-sea piping and compressed air storage system. Such a structure could bring CAES technology to a wide range of coastal locations that represent nearly 80 percent of the world's demand for electricity.

Furthermore, the growing interest in wind and solar energy has spurred interest in CAES technology. Wind farms typically generate more electricity at night when there already is a surplus of electricity. The ability to "bottle" this electric energy for daytime use (when it is most valuable) is an attractive consideration. Likewise, electricity from photo-voltaic farms in "sunny" regions could be sent through high-voltage DC transmission lines to CAES facilities elsewhere, where turbines would generate electricity year-round.

CAES technology gives utility operators the means to operate their base load plants more efficiently and provides a solution for balancing the grid. And it enables green technologies such as solar cells and wind turbines to be matched with daily and weekly demand requirements for electricity.

Unmatched experience.

The only CAES plant operating in North America, the Power South facility continues to meet its peak load demands on a daily basis. To date, the train has started reliably more than 90 percent of the time, and demonstrated greater than 95 percent reliable operation (running).

As changing market forces make CAES increasingly attractive, this ongoing success makes the Power South plant's major equipment supplier, Dresser-Rand, the logical choice for developing the next generation of CAES facilities.

CAES Plant Builds Impressive Record

Since 1991, a CAES plant in McIntosh, Alabama has been producing up to 110 MW of electrical power during periods of high peak demand. The plant's owner, Power South, uses it to boost its power capabilities during the peak daytime periods when demand for electric energy skyrockets. "Our load is primarily residential," says plant manager Lee Davis. "CAES fits well with our load shape. Basically, I'm very much for the CAES concept."

The facility uses excess electricity generated by a Power South coal-fired plant during off-peak hours (when electricity costs are lowest) to compress air for storage. It then uses that air to generate electricity and sell it at a higher price during peak periods. "We buy low and sell high," Davis says.

"Normal startup for us is 14 minutes to reach 110 MW," says Davis. "I can run down to 10 MW. It's just a better regulating tool." A dispatcher controls both the plant's compression and power generation cycles via microwave from 90 miles away.

The 140-foot train, one of the longest in the world, is almost exclusively Dresser-Rand equipment. It is technically derived from Dresser-Rand product lines that have been time- and field-tested for decades in other applications. The equipment includes single-stage turbines, standard multi-stage turbines, packaged geared turbine generators and engineered turbine generators, centrifugal and axial compressors, gas turbines, and reciprocating compressors.

The train has a centrally located motor/generator with clutches on both sides. On one side, a low-pressure compressor, intermediate compressor and high-pressure compressor work to store air in a salt dome at pressures up to 1100 psig. Four stages of compression and three inter-coolers are used to enhance cycle efficiency by minimizing compressor power.

When electric power demand peaks during the day, the process is reversed. The compressed air is returned to the surface, heated, and run through high-pressure and low-pressure expanders to power the motor/generator to generate electricity.

Power South uses an underground salt dome for compressed air storage. "We solution mined it for 629 days," Davis recalls. "That created 19 million cubic feet of cavern storage."

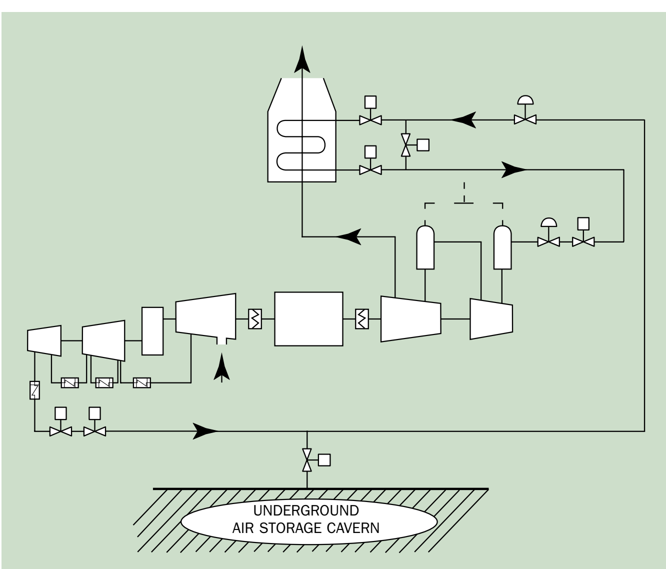
13-YEAR AVERAGE RELIABILITY			
COMPRESSION		GENERATION	
Starting	Running	Starting	Running
92.7%	99.6%	91.6%	96.7%

CAES

A Smart Choice for Many Utilities

Increases efficiency and extends base load unit life— CAES facilities enable you to optimize your base load units by minimizing load swings to maximize efficiency and extend unit life. Storing energy lets you use off-peak power to meet peak demand. This is less expensive than using traditional gas turbine peaking units or purchasing power from other sources.

Responds quickly—A CAES generator is designed to be started and brought to full load in as little as 10 minutes, eliminating the need for intermediate-load plants and providing a cost-effective way to meet spinning reserve requirements. CAES generators also have excellent load-following capability and very good part-load efficiency. Compressors can be engaged quickly to absorb load rather than reducing your base load generation.



Schematic of traditional CAES process showing air flow into and out of the storage cavern.

Flexible cycling options— The CAES system is available for compression duty when it's not in power generation mode, and can be configured for daily, weekly, or extended cycles. This allows you to "grid balance," and use inexpensive power for air storage (charging).

Environmentally friendly— CAES has environmental advantages compared to conventional gas turbines because its combustors use as little as two-thirds the fuel. Furthermore, CAES can be an attractive alternative to the costly modifications required to make coal-burning plants comply with increasingly stringent fossil fuel emissions requirements.

A CAES PRIMER

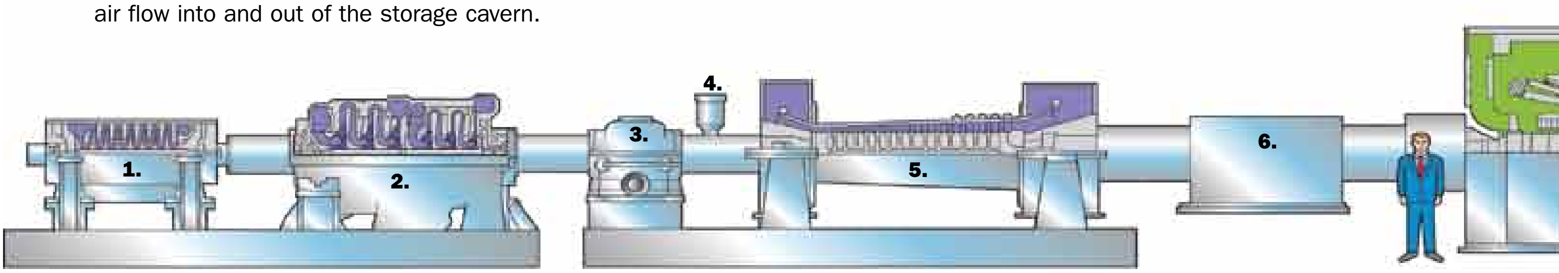
In a CAES plant, available off-peak electricity is used to power a motor/generator that drives compressors to force air into an underground storage reservoir at high pressures. This process (called "charging") usually occurs at night, and during weekends when utility system demands and electricity costs are low.

During intermediate electrical demand periods, the air is released from the reservoir, and without further compression is heated and expanded through gas- or fuel oil-fired combustion turbines to drive the same motor/generator to produce electrical power.

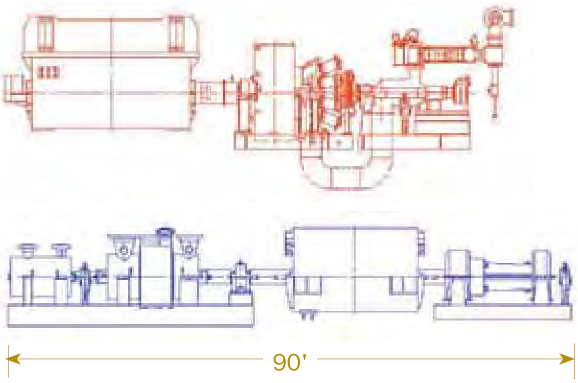
Compressed air may be stored in certain reservoirs created by solution mining bedded or domed salt formations; conventionally mining solid rock; or in aquifers and depleted natural gas fields. These formations can be found around the world.

LONG-TERM SERVICE AGREEMENTS (LTSA)

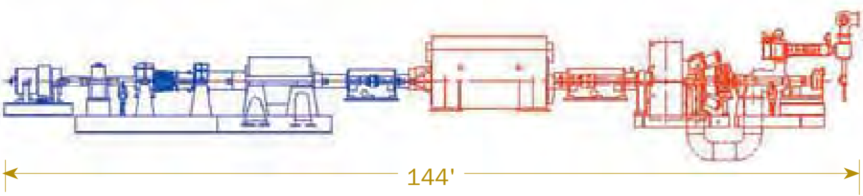
Dresser-Rand offers long-term service agreements (LTSA) to clients who require personnel to supplement or replace their maintenance organizations. A typical LTSA includes project management, technical services, field crews, and support from our OEM technical resource network. Our field teams are OEM-trained, fully equipped, committed to safety, and logistically prepared to provide professional and timely services to keep your critical equipment on-line, or restore it to full operation.



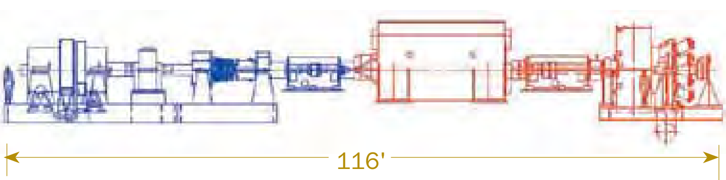
MODULAR DESIGN ALLOWS EACH SYSTEM TO BE CONFIGURED FOR MAXIMUM EFFICIENCY



Increased flexibility for simultaneous compression and power generation and quicker transition time between power generation and compression.



Matching power generation with compression flow requirements for air storage in salt domes or hard rock caverns.



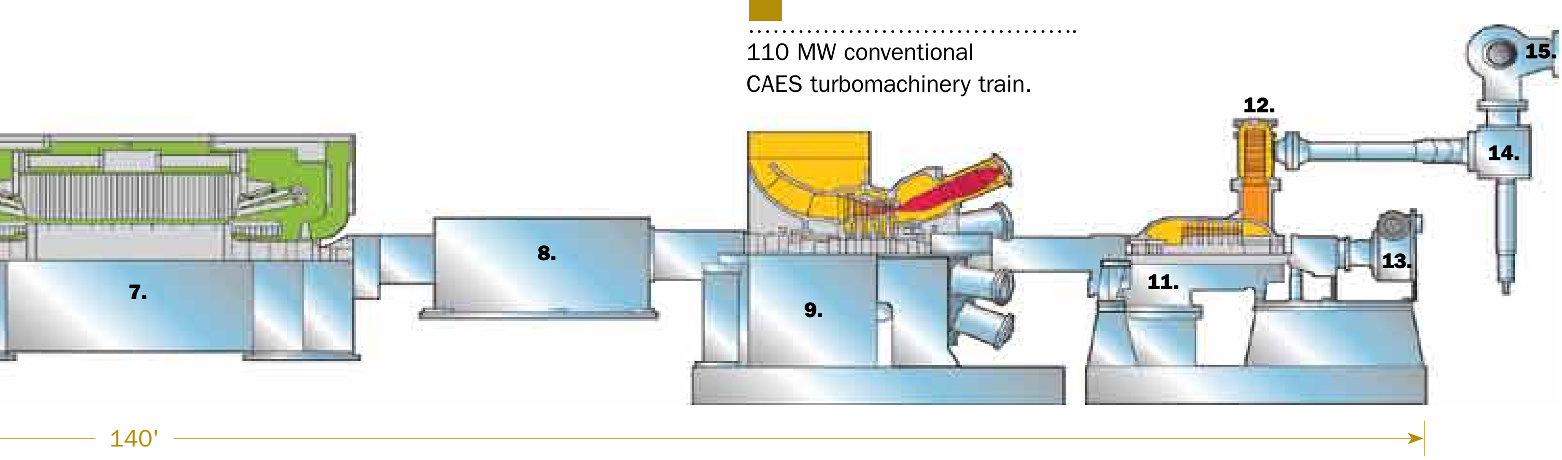
Matching power generation with lower discharge pressure requirements for air storage in aquifers.

FLEXIBLE OPERATION TO MEET CUSTOM REQUIREMENTS

- Modular, single-shaft train uses proven equipment designed to meet stringent American Petroleum Institute (API) standards
- Flexible operation modes available
- Low operation and maintenance life cycle costs achieved by:
  - Smaller, less expensive turbine components
  - Standard modules and replacement parts
  - Longer time between overhauls (compared to conventional high-temp gas turbines)
  - Lower fuel consumption (less than two-thirds that of equivalent gas turbines)
  - Wide turn-down (load) with only moderate reductions in efficiency
  - Higher efficiency at partial load
- Only a portion of the plant capacity is lost if a module of the CAES system is down for maintenance (compared to plants with large steam turbine units)
- Incremental capacity—development of storage sites
- Short lead times
- Rapid start—in as little as 10 minutes to full load
- Motor/generator can be used as a synchronous condenser to improve the system's power factor
- Output not affected by ambient temperatures

LEGEND

1. High-pressure compressor
2. Intermediate-pressure compressor
3. Speed-increasing gear
4. Turning gear
5. Low-pressure compressor
6. Clutch
7. Motor/generator
8. Clutch
9. Low-pressure expander
10. Low-pressure combustors
11. High-pressure expander
12. High-pressure combustors
13. Turning gear
14. Air throttle valve
15. Air trip valve



110 MW conventional CAES turbomachinery train.

***S*MARTCAES**™

Enhanced Renewable

Energy Solutions

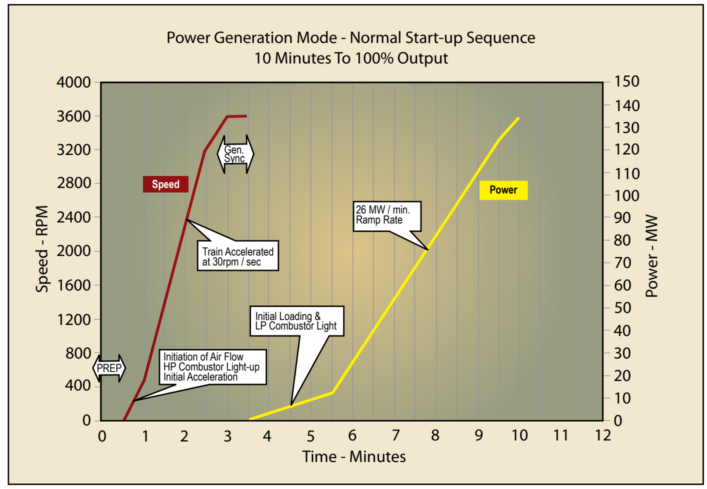


FIGURE 1: Power generation mode—normal start-up sequence

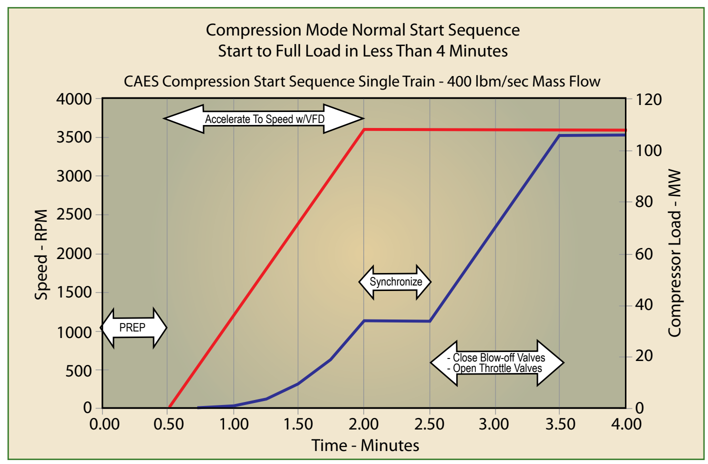


FIGURE 2: Compression mode normal start sequence

Dubbed ***SMART*CAES**™ equipment and services, this enhanced offering is more than a name; it's a reflection of Dresser-Rand's unique qualification to deliver the total integrated rotating equipment system—a "one-stop" CAES solution. This solution includes not only the rotating equipment, but all ancillary services as well—the heat exchange equipment, pollution abatement system, and the plant controls—complete with performance guarantees (both compression and power generation modes).

Over the years, related research and development from other Dresser-Rand products have been incorporated into our CAES offering (e.g., DATUM® compressor technology enhancements), and these ever-improving technologies have put CAES at the "head of its class" on every relevant subject.

SMART ON TECHNOLOGY

Technological advancements achieved since first introducing the CAES design for the McIntosh facility bring a range of benefits to Dresser-Rand's ***SMART*CAES** equipment, including operating flexibility, increased power output, reduced fuel and air consumption, improved compressor efficiency, noise reduction, and improved recuperator design.

Operating flexibility—*SMART*CAES equipment offers shorter startup times to achieve rated output in power generation mode, higher load ramping rates in power generation mode, faster compression start-up times, and faster transition between compression and power generation modes.

In power generation mode, the system is designed to start-up in less than 10 minutes to ramp output up to the rated 135 MW. Once synchronized, any output from 15 to 100 percent of rated load can be sustained indefinitely. Within this range, output may be ramped up or down at 20 percent of rated load per minute, or 27 MW per minute.

A variable speed drive system provides for rapid compression starts requiring less than 3.5 minutes. Once air is flowing to storage, the compressors may be turned down to any load between 65 and 100 percent of rated power, using variable inlet guide vanes, at a rate of 35 percent per minute (see figures 1 and 2).

For single train systems using a combination motor-generator, the variable frequency drive (VFD) system can be used to speed up the transitions between power generation and compression modes. Transitioning from power generation to compression can be achieved in five minutes, while adjusting from compression to power generation requires about 13 minutes. Multiple train systems, with separate motors for compression and generators for power production, eliminate mode transition time. The maximum transition time equals startup time in the desired mode.

Power output—The output of ***SMART*CAES** turbo expanders was increased from 110 MW to 135 MW. Combining modern analytical techniques and upgraded materials, the calculated safety factors for both the high-pressure and low-pressure turbines' flowpaths remain virtually unchanged, despite a total output increase exceeding 20 percent.

Fuel and air consumption—Turbine and system enhancements such as better recuperator effectiveness result in a two percent heat rate improvement, coupled with a 1.2 percent reduction in specific air consumption (SAC), across the design operating range from 20 MW to 135 MW. The heat

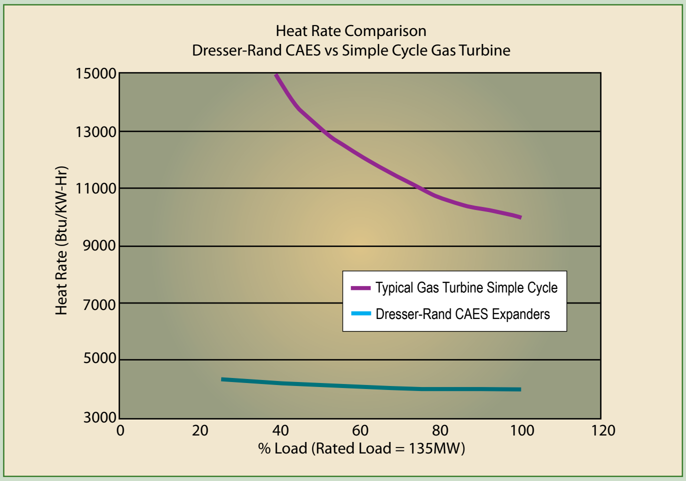


FIGURE 3: Heat rate comparison

rate of the Dresser-Rand ***SMART***CAES expanders is low and flat over a wide range of turndown from 100 percent load to 25 percent load because the expanders operate independent of the air compressors (see figure 3).

Compressor efficiency—Dresser-Rand's DATUM centrifugal compressor technology, more advanced axial compressor flowpath aerodynamics and careful design of the intercooled compression cycle all provide significant improvements in overall efficiency. Depending on final parameters, overall compression train flange-to-flange polytropic efficiency is in the mid-80 percent range in terms of energy consumption. The efficiency of the Power South CAES compressor train installed and operating in McIntosh is in the low 80 percent range (approximately three percent lower than Dresser-Rand's current CAES offering).

Noise reduction—Our patented noise reduction technology (D-R® duct resonator array) can achieve up to a 10 dB reduction in noise levels compared to centrifugal compressors that do not utilize this acoustic technology.

Recuperator design—The exhaust recuperator is a simpler design, with 85 percent heat transfer effectiveness compared to 75 percent in the earlier design. Strategically placed rows of stainless steel tubes avoid corrosion and exfoliation problems, and the entire recuperator is designed to operate at maximum air storage pressure, eliminating the cost and maintenance of pressure reducing valves. This change also makes sliding pressure cycles feasible where advantageous.

SMART ON THE ENVIRONMENT

The technological improvements to ***SMART***CAES equipment and services offer emission control options capable of meeting all current regulatory requirements for NO_X and CO limits. With features that can meet current emissions requirements, ***SMART***CAES equipment can do its part to reduce the buildup of greenhouse gases in the atmosphere and combat climate change.

A simple diffusion flame combustor with H_2O injection for primary NO_X control, coupled with an exhaust selective catalytic reduction system for final NO_X control, provides stable operation at high turndown ratios. It's possible to achieve final exhaust emission levels of 2 ppm NO_X and 2 ppm CO, corrected to 15 percent O_2. This means, depending on the operating profile, many potential CAES sites would fall under small-source emission limit rules. In addition, the VFD system reduces the compression start time, eliminating expander emissions from compression starts.

When used in conjunction with renewable energy such as wind or solar, ***SMART***CAES equipment has one-third the emissions of a conventional gas turbine.

SMART ON BUSINESS

The world's increasing focus on cleaner, greener energy use presents Dresser-Rand with an ideal opportunity to successfully integrate our CAES technology into new markets.

We recently secured a patent for a concept to combine a conventional CAES facility with a sub-sea piping and compressed air storage system. Such a structure could bring CAES technology to a range of coastal locations that represent nearly 80 percent of the world's demand for electricity.

The growing popularity of wind and solar energy could also spur interest in ***SMART***CAES solutions. Wind farms typically generate more electricity at night, when there's already a surplus, and the ability to "bottle" electric energy for daytime use is an attractive option. Within the solar market, electricity from photo-voltaic farms in sunny regions could be transmitted to facilities that use ***SMART***CAES equipment in other areas, where turbines would generate electricity year-round.

The world would benefit from increased use of renewable energy sources, such as wind and solar, however, a common reality is that they are inherently intermittent and to some degree unreliable. ***SMART***CAES equipment provides an excellent tool for "smart grid" management by having excellent load following capability, helping base load assets to be more efficiently utilized during off-peak times, and by being able to provide ancillary services such as VAR support, regulation and reserve.

The dynamics of the worldwide energy market are changing, and ***SMART***CAES solutions are one example of how Dresser-Rand is repositioning its offerings to address global needs. Renewable energy sources can benefit from the bulk energy storage capabilities that ***SMART***CAES equipment offers. ***SMART***CAES equipment is also complementary to energy conservation and development efforts associated with the "smart grid," giving utility operators the means to run their base load plants more efficiently.

Considering the careful research, advancements and efficiencies surrounding ***SMART***CAES equipment and services, its potential benefits are an obvious choice for creating an efficient power generation system.

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DRESSER-RAND

Bringing energy and the environment into harmony.℠

Huntorf Compressed Air Energy Storage Plant

321 MW

Compressed Air Energy Storage (CAES)

Germany's Huntorf Compressed Air Energy Storage Plant is the world's first and still the largest utility-scale, commercial compressed air energy storage plant (as of April 2012).

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http://www.uni-saarland.de/fak7/fze/AKE_Archiv/AKE2003H/AKE2003H_Vortraege/AKE2003H03c_Crotogino_ea_HuntorfCAES_CompressedAirEnergyStorage.pdf
http://www.bine.info/en/hauptnavigation/topics/renewable-energy-sources/wind-energy/publikation/druckluftspeicher-kraftwerke/
http://www.kraftwerk-wilhelmshaven.com/pages/ekw_en/Huntorf_Power_Plant/Media_Center/index.htm

The 321 MW Huntorf plant has operated since 1978, functioning primarily for cyclic duty, ramping duty, and as a hot spinning reserve for the industrial customers in northwest Germany. Recently this plant has been upgraded and now serves to level the variable power from numerous wind turbine generators in Germany.

The Huntorf power plant pumps air at off-peak times into two salt caverns totaling 300,000 cubic meters. These caverns are between 600 and 850 meters deep. At peak loads this air is drawn out and burned together with natural gas. It is then used in the gas turbine to generate power. The gas turbine is capable of black starts, i.e. it can be started without external energy and can reach its full output of 321 MW within (6) minutes.

The Huntorf power plant is fully automated.

Location:	Huntorf, Germany
Date Commissioned:	1978 (upgraded from 290 MW to 321 MW in 2006)
Rated Capacity:	321 MW over 2 hours.
Annual Production:	N/A
Capacity Factor:	**TBD**
Cycle Efficiency:	42%
Carbon Offset:	N/A
Owner:	E.O Kraftwerke GmbH (BBC Mannheim designed the plant).
Generation Offtaker:	E.O Kraftwerke GmbH
Generation Technology:	Diabatic CAES. (2) cylindrical salt caverns each 150,000 cubic meters.
Cost:	Unknown

SANDIA REPORT

SAND2012-0388
Unlimited Release
Printed January 2012

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A Study for the DOE Energy Storage Systems Program

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Abstract

The Iowa Stored Energy Park was an innovative, 270 Megawatt, $400 million compressed air energy storage (CAES) project proposed for in-service near Des Moines, Iowa, in 2015. After eight years in development the project was terminated because of site geological limitations. However, much was learned in the development process regarding what it takes to do a utility-scale, bulk energy storage facility and coordinate it with regional renewable wind energy resources in an Independent System Operator (ISO) marketplace. Lessons include the costs and long-term economics of a CAES facility compared to conventional natural gas-fired generation alternatives; market, legislative, and contract issues related to enabling energy storage in an ISO market; the importance of due diligence in project management; and community relations and marketing for siting of large energy projects. Although many of the lessons relate to CAES applications in particular, most of the lessons learned are independent of site location or geology, or even the particular energy storage technology involved.

ACKNOWLEDGMENTS

The authors acknowledge the guidance and support of the members of the Iowa Stored Energy Plant Agency (ISEPA), representing 57 municipal utilities in four states and owners of the Iowa Stored Energy Park (ISEP), and Bob Haug, Executive Director of the Iowa Association of Municipal Utilities.

In addition to funding from the ISEPA members, this work was funded in part and supported by the Energy Storage Program of the U.S. Department of Energy's Office of Electricity. The authors thank Dr. Imre Gyuk, DOE Energy Storage Systems Program Manager, for his support and insights.

Funding support for the test-well-drilling program for the Iowa Stored Energy Park was provided by the Iowa Power Fund.

The authors are also appreciative of the various companies and subject matter experts including Lee Van Atta, Ruben Moreno, and Tim Wang of R.W. Beck (an SAIC Company); Sep Van Der Linden of Brulin Associates; Rahul Walawalkar of Customized Energy Solutions; Mike King of Hydrodynamics Group, LLC; Tim Hower and Dennis Holler of MHA Petroleum Consultants; Steve Bauer of Sandia National Laboratories Geomechanics Department; the Iowa State Geologists of the Iowa Department of Natural Resources; Dave Vincent of Dresser-Rand; Tom Wind of Wind Consulting; and their respective teams that provided their skills and expertise in the design, development and assessment of the innovative ISEP compressed air energy storage facility and to this report. The authors also thank Todd Hillman, Rao Konidena, Durgesh Manjure, Dale Osborn, and David Van Beek of the Midwest Independent System Operator for their interest, advice, and cooperation.

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TABLES

ACRONYMS

AS	Ancillary Services
AWEA	American Wind Energy Association
CAES	Compressed Air Energy Storage
CAREBS	Coalition for the Advancement of Renewable Energy through Bulk Storage
CC	Combined Cycle
CEC	Clean Energy Credit
CES	Customized Energy Solutions
CO_2	Carbon Dioxide
CREB	Community Renewable Energy Bond
CT	Combustion Turbine
DIR	Dispatchable Intermittent Resources
DOE	Department of Energy
DR	Demand Response
D-R	Dresser-Rand
EASE	Electricity and Air Storage Enterprises, Inc.
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESA	Energy Storage Association
FERC	Federal Energy Regulatory Commission
FTE	Full-Time Equivalent
GE	General Electric
HRSG	Heat Recovery Steam Generator
IAMU	Iowa Association of Municipal Utilities
IOU	Investor-Owned Utility
IPF	Iowa Power Fund
ISEP	Iowa Stored Energy Park
ISEPA	Iowa Stored Energy Plant Agency
ISO	Independent System Operator
ITC	Investment Tax Credit
IUB	Iowa Utilities Board
kV	kilovolt
kW	kilowatt (thousands of Watts)
kWh	kilowatt-hour (thousands of watt-hours)

LMP	Locational Marginal Price
LSE	Load-Serving Entity
MAPP	Midcontinent Area Power Pool
MISO	Midwest Independent System Operator
MRES	Missouri River Energy Services
MVP	Multi-Value Project
MW	Megawatt (millions of Watts)
MWe	Megawatt (millions of Watts) electrical
MWh	Megawatt-hour (millions of watt-hours)
NOPR	Notice of Proposed Rulemaking
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
REC	Renewable Energy Credit
RES	Renewable Energy Standards
RT	Real Time
SA	Schulte Associates LLC
SCED	Security Constrained Economics Dispatch
SME	Subject Matter Expert
SNL	Sandia National Laboratories
SPA	System Planning Analysis
TO	Transmission Owner
WAPA	Western Area Power Administration

EXECUTIVE SUMMARY

This report summarizes the due diligence lessons learned in development of the Iowa Stored Energy Park (ISEP) project—the Lessons from Iowa. The purpose of the report and related documentation and marketing efforts is to enable these lessons to assist other storage projects in their development. The different areas of interest are broken into sections, and each section summarizes the lessons learned in bulleted form. Further details and resource references for each Lesson are provided in the individual sections.

Section 1: Introduction

Lessons from Iowa represent the due diligence lessons learned in development of the ISEP project. ISEP was a proposed 270 Megawatt (MW), $400 million compressed air energy storage (CAES) project to be located near Des Moines, Iowa, with in-service proposed for 2015. ISEP was owned by the Iowa Stored Energy Plant Agency (ISEPA), a public power agency organized under Iowa Statutes 28e, and representing 57 municipal utilities in four states (Iowa, Minnesota, North Dakota, and South Dakota).

The project planned to take advantage of the site's favorable geology and its location on the edge of a very favorable wind energy regime. Also, Iowa is a leading state in wind energy development. While ISEP was focused on CAES technology in the Midwest Independent System Operator (MISO) market, most of the lessons learned are independent of site-specific geology, and should be directly applicable to multiple storage technologies in multiple markets.

To provide context for the reader:

- ISEP was primarily intended to be a source of capacity as well as providing significant amounts of daily energy to the project owners. As such, it was intended as an "intermediate" supply resource available for operation up to 12 to 16 hours per day on weekdays, year-round.
- Providing ancillary services to the regional market was considered a secondary goal, rather than a primary goal of ISEP.
- ISEP was designed to be a large (270-MW) bulk storage facility located on the regional transmission grid. This contrasts to various other storage applications co-located with renewables facilities "behind the customer's meter," or located within a utility's distribution substation.
- The project was originally conceived by public power entities for use by public power entities. It was later revised to enable investor-owned participants as well.

The Lessons show that cost and economics considerations, while important, are only two of the challenges for implementing cost-effective bulk storage. Institutional, policy, legislative, and market forces also exist and need to be addressed.

Section 2: Project History

The benefit of hindsight shows that many of the Lessons from Iowa resulted from who the project owners were (and were not), and how the project was originally assembled and then evolved. The ISEP project was originally conceived as a public power project with public power (not-for-profit) owners. The public power-focused history of the ISEP project favorably affected the financials of the project, and negatively limited the market for project participation. The original participants in ISEP were municipal distribution utilities with extensive experience in distribution, but little experience in power plant project development. This negatively affected their ability to move the project forward until participants who had such experience joined ISEPA later in the project. The ISEPA members did not own wind energy or transmission facilities near the ISEP project site. They also did not own conventional intermediate or baseload generation facilities near the site. This negatively affected their ability to evaluate and capture all of the potential storage benefits of the ISEP facility.

Section 3: Economics

In evaluating costs, it is difficult to achieve comparable cost estimates for energy supply alternatives from different sources. Accordingly, the project spent much effort to develop costs for the proposed storage facility and conventional alternatives that were directly comparable. The owner's in-service capital cost of a bulk storage CAES facility like ISEP is about 20% higher than a comparably sized, conventional natural gas-fired combined-cycle electric generation facility. The fixed and variable O&M costs and environmental emissions rates per kilowatt-hour (kWh) of a CAES facility are similar to comparably sized conventional generation alternatives.

A CAES facility is operationally more flexible than a conventional generation alternative. It can start up faster, ramp up and down faster and in a linear manner, accommodate multiple daily startups and shutdowns better, and has a lower minimum load level. In addition, it can store electricity. A CAES facility has a significantly better heat rate (better fuel efficiency) in generation mode than a conventional natural gas-fired generation facility. This means lower fuel use during the generation cycle, and lower emissions.[1]

A bulk storage CAES facility like ISEP can be cost-effective when operated in the MISO market. It can also be more cost-effective than conventional, natural gas-fired generation alternatives.

The ISEP studies outlined in this section describe how bulk storage has unique attributes that can reduce system-wide production costs, improve the operation and profitability of regional conventional generating plants, decrease cycling (and operating and maintenance [O&M] costs) of conventional plants, offer a 100% dispatchable off-peak load for use by system operators to optimize the regional system, and enable an electric options market to address hourly price volatility (both upward and downward).

[1] Exclusive of fuel used in the storage (compression) cycle.

In addition, a bulk storage facility like ISEP can be supportive of renewables development and positively affect the economics of a system. Dispatched against MISO market prices, it can store electricity during off-peak periods when the wind is blowing, and generate during on-peak periods when the wind is not blowing.

Section 4: Transmission

Much has been written about the potential benefits of storage in reducing or deferring transmission investment. As a result, the transmission benefits identified in the ISEP economics study (specifically, the lack thereof) was disappointing. However, the reasons for this outcome are illustrative of issues facing bulk storage.

Little or no such benefits were found because ISEP was a bulk storage unit to be located on the transmission system "outside the customer's meter," as compared to a distributed storage unit such as a battery collocated with renewable resources "behind the meter." This meant the ISEP storage could be subject to potential transmission constraints *between* the storage and the renewable resource.

The MISO system in and near Iowa currently needs very large amounts of additional new transmission. The magnitude of that need significantly exceeds the size of the ISEP storage facility. From a generation interconnection perspective, whether the ISEP facility happened or not would not materially change these transmission development plans.

The ISEP owners do not own transmission near the proposed ISEP storage site, so they would not directly benefit from any reduced investments from transmission deferral.

The MISO generator interconnection study process examines transmission requirements as driven by the generator side of the storage facility. It does not consider the potential transmission savings of the storage (dispatchable load) aspect of the storage facility.

The amount of analytical work involved in determining any potential transmission benefits of the ISEP storage in reducing the current curtailment of Iowa wind resources was beyond the scope and resources of the ISEP economics study, and would have required the cooperation of wind energy and transmission owners who were not participants in ISEP. As a result, no cost benefits for transmission were included in the ISEP economics analyses.

This outcome does not necessarily say that a storage facility like ISEP would not have transmission benefits. However, it represents "lessons learned" that location of the storage on the transmission system, particularly relative to generation facilities that could benefit from the storage, matters; ownership (of the storage) also matters, as discussed in Section 5, particularly with regard to transmission and integration with renewables; and the regional ISO has not yet developed sufficient planning processes (as further described in Section 4 with regard to transmission) and tariffs (as described in Section 5) necessary to accommodate and enable storage.

Section 5: Markets and Tariffs

An "ideal" storage owner would be able to internalize all the benefits of the various valuable storage attributes for themselves. However, in an ISO with centralized dispatch, most of these benefits are disseminated to entities other than the storage owner. The ISO needs to actively innovate and enact market and tariff improvements to "commoditize" the various beneficial attributes of storage, so the storage owner can "monetize" them as incentive for them to own and operate the storage. The authors offer multiple suggestions for the tariff improvements necessary for an ISO to enable storage in their market area.

Legacy computer resource planning models used by utilities do not do a good job of modeling storage. They simply do not capture all of the beneficial attributes of storage. As a result, ISO policy toward storage should not be based primarily on such models. Conversely, MISO policy toward storage and renewables should drive necessary improvements in the models.

MISO is in the process of performing a major study of storage. Without ISEP, MISO lacks a new large storage project to drive the particulars of needed policy and tariff development for storage and renewables.

Section 6: Renewables Policy and Legislation

There is a growing realization that renewables and cost-effective storage can be combined and coordinated into an effective combination electric supply resource for the future. Because it enables renewables development, bulk storage itself should be eligible for credit against state renewable energy standards (RES) or federal clean energy standards requirements. Legislation or other policy initiatives are necessary to enable the full benefits of storage in encouraging and supporting renewables development.

Some examples:

- Passing the investment tax credit (ITC) and Community Renewable Energy Bond (CREB) financing provisions of the federal STORAGE 2011 Act sponsored by Senators Bingaman, Wyden, and Shaheen into law. This would have a materially beneficial effect on storage economics. This bill was reintroduced in the U.S. Congress in November 2011 as the STORAGE 2011 Act (S. 1845) by Senators Wyden, Bingaman, and Collins.
- Assigning state Renewable Energy Credits (RECs) or federal Clean Energy Credits to the storage function itself, if the storage can demonstrate it supports renewables development and operations.
- Classifying bulk storage itself as a Clean Energy Technology in any federal Clean Energy legislation, if the storage can demonstrate it is supportive of renewable energy.
- Creating a market for "firm" renewable energy. This is where the combination of renewables and storage is used to create a renewable product with both energy *and* dependable capacity attributes that has value above and beyond a corresponding amount of conventional, fossil-fueled capacity and energy.

Section 7: Siting

Due diligence demands that a storage project engage in an active and collaborative public and government affairs initiative. When siting an underground storage project in a community, market research of the community in advance is useful. Once market research is gathered, it should be used in real and practical ways.

It is important for the project to appear credible and trustworthy early in the process. Community objections to a new project are often based on a lack of information. To the maximum extent possible, decision processes should be transparent and accessible to the community affected; and the local community should be involved in decisions about where the plant facilities will be located.

Section 8: Project Management

A storage project by definition involves multiple and diverse parties. These would include the storage facility owner(s), transmission owner(s), wind energy resource owner(s), power purchase agreement off-taker(s), the power market(s), and potentially others. In an open access environment, it is unlikely that all of these parties would be the same entity.

It is a common misconception that development of a power plant involves only physical construction and operations. Instead, the initial years of development involve organizational definition and relations, market development, geology research, cost estimates, economic studies, contracts, financing considerations, and regulatory permitting.

Development of a bulk storage project like ISEP takes years before a Notice to Proceed to purchase equipment and construction occurs. During the initial development phase, the project Board's and Project Manager's primary job is due diligence, as a storage project needs an articulated due diligence/development plan to be successful.

A storage project by its nature will involve multiple and diverse participants, and this needs to be built in from the start. All prospective project owners/participants should be qualified by the project before they join it. Unless the project capacity is fully subscribed from the start, its organizational structure, financing plan, and ownership contracts plan need to think broadly regarding the types of owners (i.e., public power or investor-owned) that would be eligible to participate in it. Project participation should be on a project MW output-share basis from the start, rather than only investment dollars-based. All owners' participation should be based on paying their pro-rata share of project costs, based on their respective planned shares of the plant output.

On important issues, second opinions should be sought when there is uncertainty because of lack of data or other factors. Politics internal to the project owners' group can have major consequences on a project; consideration of the needs of all the participants is important to provide the necessary cooperation for the project to proceed.

Because such projects will likely involve multiple and diverse project owners, and because the complexity of characterizing the aquifer-based reservoir will involve expert opinions rather than only facts, the due diligence team and project manager should report to the project as a whole, rather than an individual project owner.

Section 9: Geology

From a technical geology perspective, accomplishing the site selection and geologic analysis for a greenfield, aquifer-based CAES project where there is no existing data or prior use of the reservoir is time-consuming and challenging.

From the business perspective of the storage facility owner, developing a greenfield, aquifer-based CAES project is problematic. Although the project's long-term economics looked favorable, the geology was a negative factor.

Section 10: Observations and Recommendations for Follow-on Work

An entity or entities contemplating ownership of or participation in a bulk storage project need to consider who they are, and what kind of market they will be operating in. This affects whether they can achieve the full gamut of potential storage benefits described in Section 3 in such manner that they will be sufficiently incentivized to own and operate the storage facilities.

Off-peak to on-peak price spread arbitrage is often considered the primary potential economic benefit of a bulk storage unit, but the ISEP experience and studies show it is not the only one. Accomplishing bulk storage will require the tapping of the full range of storage's attributes, benefits, and value described in Section 3:

- Off-peak to on-peak price arbitrage (intrinsic value).
- Option value to address price and quantity variability (extrinsic value).
- Fast startup, multiple daily startups/shutdowns and fast ramping (ancillary services).
- 100% dispatchability of off-peak load (to improve capacity factors and reduce cycling of conventional plants, and reduce curtailment of renewable resources).
- Ability to enable more renewable resources than could be accomplished without storage.
- Transmission deferral.

A storage owner or participant must be ready and capable to innovate if they hope to achieve the full benefits of such a project. As described in Section 5, many of the market mechanisms necessary to enable new storage projects do not currently exist.

The ISEP project was focused on future operation in the MISO market. Although specific market operating rules vary among the various ISOs, the conceptual lessons learned about what it takes to make bulk storage happen in MISO would likely apply to other ISO markets as well. MISO is working on various storage studies and tariffs, and these efforts need to result in tariffs that can enable the full range of beneficial storage attributes and the full value of storage for the storage owners and the MISO region as described in Sections 3 and 5. This would include ancillary services tariffs, creation or participation in an electric options market as necessary to achieve the full extrinsic value if the storage owner cannot monetize such value themselves, and coordination with various legislative initiatives providing incentives for additional renewables (and related storage) development.

Another market concept that deserves consideration is the creation of a market product involving "firm" or "firmed" renewable energy, with both energy and capacity components. Historically, renewables have been thought of as primarily an energy resource because they are intermittent. Combinations of renewables and storage could provide renewable energy capacity value as well. This combination should be valued and priced as a premium product compared to conventional energy sources, similar to organic produce sold in supermarkets.

As described in Section 5, existing computer resource planning models do not do a good job calculating the potential benefits of storage. MISO is working on improved modeling techniques, but more improvements need to happen before the models. In the meantime, the authors suggest that MISO policy toward encouraging storage, particularly to address increasing levels of intermittent renewables on the regional system, should drive modeling improvements, rather than modeling shortcomings suggesting MISO storage policy.

Demonstration storage projects can also be useful. It is recognized that from a practical perspective, MISO and other markets probably need specific new proposed bulk storage projects of material scale that would help drive the need for proved tariffs, markets, and planning models. Doing such development in the abstract without an actual specific project to focus on is difficult, and would probably be (rightfully) assigned a low work priority.

The need for storage is growing, at least in part, as a result of legislatively driven incentives for renewable energy development. For the same reasons, storage should be similarly encouraged by legislation too. Simply, storage enables existing renewables (and other resources) to operate better, and enables more renewables to be built than could be accomplished otherwise.

Legislation at the federal level for storage should include passage of the STORAGE 2011 Act (as described in Section 3 and 6) or something similar, including ITCs for investor-owned bulk storage owners and CREB financing for public power entities. If a national RES or Clean Energy Standard is passed, then bulk storage that demonstrably enables renewables operation and development should itself be classified as a renewable or clean energy resource, and thereby eligible itself for RECs or clean energy credits.

Legislation at the state level for storage should include recognition of the role of bulk storage in enabling renewables development and achieving state RES. For those bulk storage facilities that demonstrably enable renewable operation and development their storage energy should be, in whole or in part depending on the project-specific circumstances, credited against the owners' state RES requirements and eligible for RECs of their own.

1. INTRODUCTION

1.1 Purpose

The Iowa Stored Energy Park (ISEP) project, a 270 Megawatt (MW), $400 million compressed air energy storage (CAES) project to be located near Des Moines, Iowa, was terminated on July 28, 2011 [1]. The Iowa Stored Energy Plant Agency (ISEPA), an Iowa Statutes Section 28e power agency representing 57 municipal utilities in four states who owned the project, ended the project after eight years of development because of project site geology limitations. About $8.6 million had been invested in ISEP by the ISEPA members, the U.S. Department of Energy's (DOE's) Storage Systems Program, and the Iowa Power Fund.

With the encouragement and support of the DOE's Energy Storage Program, "Lessons from Iowa" (referred to in this document as "Lessons") is the documented lessons learned of the ISEP project. The purpose of this report and related documentation and marketing efforts is to enable Lessons from Iowa to assist other storage projects in their development. By documenting Lessons, it is hoped that other storage projects, whether they use CAES or other technologies, can avoid confronting the issues and challenges addressed by ISEP. Most of the Lessons are independent of geology, or even of the storage technology used.

1.2 Content

Lessons represents the practical experience of public power utilities in developing a large, utility-scale, bulk storage project in an independent system operator (ISO) marketplace. The content of Lessons is designed to enable the reader to quickly identify the lessons learned in the project, and access the detailed project reports that document the individual lessons.

This report and associated documentation are organized in the following sections:

- An Executive Summary that overviews the Lessons in each section category.
- Section 1: Introduction (this section).
- Section 2: Project History.
- Section 3: Economics.
- Section 4: Transmission.
- Section 5: Markets and Tariffs.
- Section 6: Renewables Policy and Legislation.
- Section 7: Siting.
- Section 8: Project Management.
- Section 9: Geology.
- Section 10: Recommendations for Follow-on Work.

Each section includes references to the detailed project reports developed during the ISEPA project that provide additional background information on each section topic.

This report and the documentation library will be posted for public reference and use on the ISEPA website at www.isepa.com.

1.3 Context for the Reader

The Lessons from Iowa provide knowledge gained that can be used in the development of other storage projects.

The ISEP experience represents some of the most-current development work in bulk, grid-connected electricity storage in general, and CAES in particular. Also, in contrast to other, privately developed storage projects, the public nature of the ISEP project allows Lessons to be openly offered for public information and use.

While the ISEP project was focused on CAES technology, many of the lessons learned are independent of geology, and should be directly applicable to multiple storage technologies. Because ISEP was to be a bulk storage unit located on the transmission grid, some of the Lessons (particularly transmission system impacts) are unique to such a configuration. Some Lessons are not directly applicable to distributed storage applications where the storage is located behind the customer's meter, or within a utility's distribution substation. Because the ISEPA members intended ISEP to be a source of intermediate-duty capacity and energy, it was designed to be an energy machine, with ancillary services being only of secondary interest to the extent that could provide additional revenues for the project. This is in contrast to other storage technologies (i.e., flywheels and some applications of batteries) that have relatively short durations of output and thus see providing ancillary services as their primary source of revenue.

Because ISEPA is a public power entity, the primary focus of Lessons (particularly the economics studies) is from a public power perspective. However, because investor-owned participants/owners were also envisioned for the project, sensitivity analyses are included where financial and other economic results would vary from that of a public power owner.

Much of the ISEP work presented in Lessons from Iowa was performed as due diligence to help the ISEPA members and potential new project participants decide whether participating in the storage project was a good idea for them and for their customers. As such, Lessons represents a learning laboratory and process for anyone interested in considering storage, and whether storage will work for them. Lessons shows that costs and economics, while important, are only two of the challenges for implementing cost-effective bulk storage. Institutional, legislative, and market forces and market development issues also exist. Simply, storage is very different from the conventional generation and transmission resource technologies that have been applied in the electric grid to date. As described in Sections 3 and 7, in the process of the ISEP project the ISEPA members realized their strengths and weaknesses as candidates to own bulk storage. The corresponding costs and benefits for other storage ownership candidates will depend on their unique needs and characteristics, their customers, the electric market in which they operate, and certainly their level of innovation.

2. PROJECT HISTORY

2.1 Introduction

This section describes the history of the ISEP project and its owners, the ISEPA. The benefit of hindsight shows that many of the Lessons from Iowa resulted from who the project owners were (and were not), and how the project was originally assembled and then evolved.

2.2 Lessons

The ISEPA project was originally conceived as a public power project with public power (not-for-profit) owners. The project began as an effort by the Iowa Association of Municipal Utilities (IAMU, www.iamu.org) to develop an energy project for its members. The following time line outlines the chronology of project development.

In 2002, an IAMU study indicated a need for municipal utilities to secure intermediate[2] electricity supply resources. IAMU determined that CAES technology could meet that need. An ISEP Committee of IAMU members was formed to lead the effort. Iowa has an excellent wind energy regime. Figure 1 illustrates the wind potential in the United States, and highlights that most of the potential exists in the Midwest, including Iowa.

In 2003, the ISEP Committee raised $680,000 in project development funds from IAMU members. As an incentive, the members were offered multiples on their investments contingent upon the ISEP project reaching commercial operation. The ISEP Committee commissioned Burns & McDonnell to develop a conceptual design and cost estimate for the project [2].

In 2004, the project received a $150,000 Federal DOE grant. A study of a potential site near Ft. Dodge, Iowa, concluded the site would not meet the participants' needs [3]. Municipal funding of the project exceeds $1 million.

In 2005, multiple project studies were performed. Among them, a generic (non-site-specific) feasibility study by Black & Veatch Corporation found, "The project appears to be economically viable under a number of scenarios, and the project risks can be controlled." [4] A screening report by Hydrodynamics Group LLC identified possible geologic sites in Iowa [5]. The ISEPA was formed as a public power agency under State of Iowa Statutes 28e for purposes of administering the ISEP project. ISEPA took over the role of project governance from the ISEP Committee and IAMU. Eleven IAMU members became the original ISEPA members.

ISEPA received a $1.5 million DOE grant for the project.

In 2006, as described in Section 9, the Dallas Center site near Des Moines was chosen from other site alternatives, primarily because of its relatively favorable geology. As shown in Figure 2, the site was on the edge of a very favorable wind energy regime.

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2 The term "intermediate" refers to energy resources that are neither baseload (operating continuously) or peaking (operating only at peak load times). Instead, they operate on a daily basis (typically during daylight hours on weekdays) to meet the rise and fall of utility customers' typical electric usage.

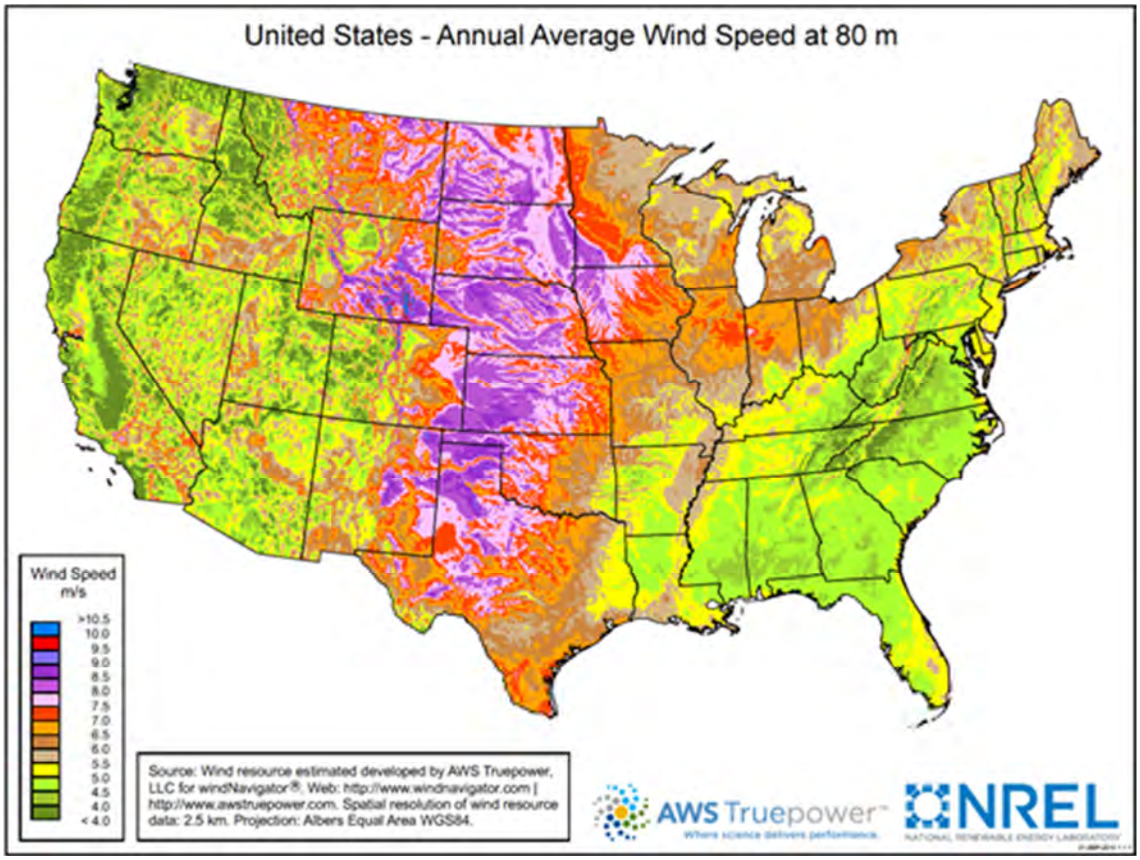

Figure 1. Annual average wind speed at 80 meters height [6].

Initial seismic studies of the Dallas Center Dome site were performed. Hydrodynamics interpreted the data and confirmed the presence of a geologic dome at the site [7].

ISEPA received another $1.5 million DOE grant for the project. The ISEPA Project Team determined that an overall public relations effort was necessary. Frank Magid Associates of Marion, Iowa, was retained to develop the plan. The resulting media strategy was executed with press and television coverage. See Section 7 for details.

In 2007, additional seismic studies were performed on the Dallas Center site to supplement and further extend initial studies done the previous year. Hydrodynamics used the collective seismic data to develop a computer reservoir simulation model, using the characteristics of the nearby Northern Natural gas storage site at Redfield as an analog [9].

A market feasibility study was performed, which concluded “the Project is estimated to yield positive net margin.” [10]

Congressional earmarks were eliminated in FY 2007. However, the DOE/OE Energy Storage Program provided $200K in funding to continue the project. The project governance structure was reorganized with ISEPA established as an Iowa Statutes 28e public power agency.

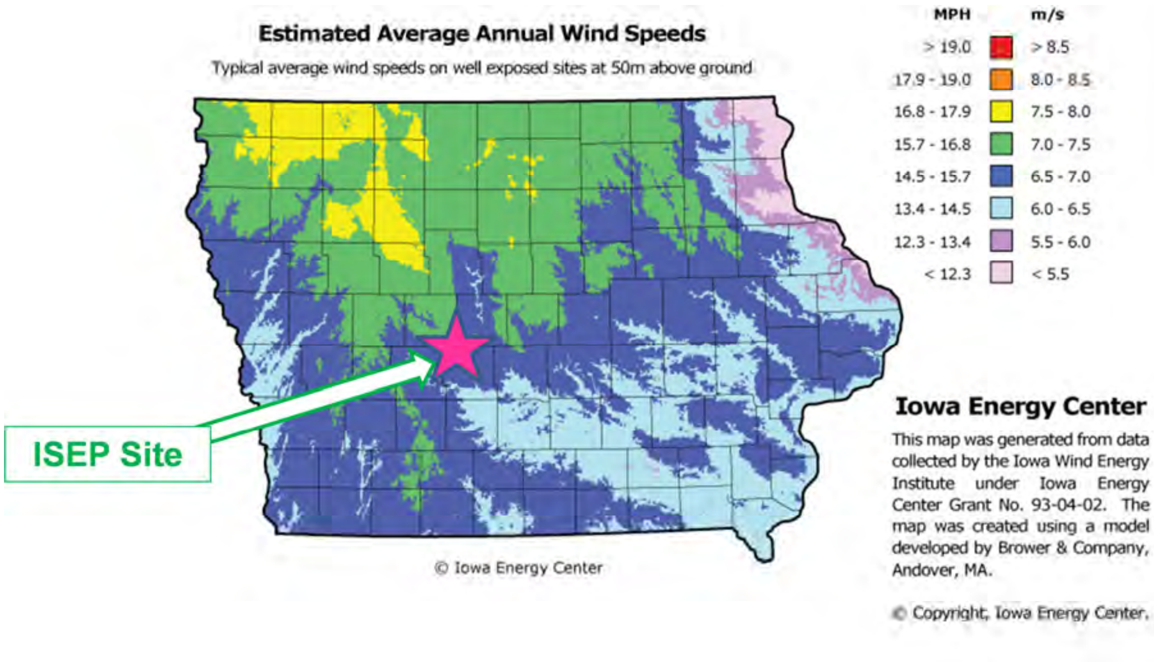

Figure 2. Annual average wind speed in Iowa and ISEP storage project site [8].

In 2008, ISEPA received an additional $1.5 million DOE grant for the project. ISEPA applied for and received a $3.2 million loan from the Iowa Power Fund to support test well drilling and pump testing at the Dallas Center site [11]. The loan was to be repaid, or converted to equity ownership in ISEP by the State of Iowa, contingent on the ISEP project successfully achieving commercial operation. The loan was forgivable if the project was not successful.

A study performed by Black & Veatch for Missouri River Energy Services (MRES) concluded "…that within a wide range of reasonable expected values for capacity and energy services, participation in the ISEP unit proposed by the Iowa Stored Energy Plant Agency (ISEPA) would be to MRES's economic benefit." [12]

In 2009, MRES and Utilities Plus, both municipal power agency's with experience and internal staffing for energy supply resource planning and power plant project development, joined ISEPA. A land acquisition strategy was developed, and land appraisals were acquired. The "Keith" property was purchased, as it represented the then-known center of the top of the storage reservoir structure. In November, the Mortimer property was acquired through a bidding process described in Section 7. Along with the Keith property, this was intended as the above-ground plant site. Discussions began within ISEPA regarding the need to retain an independent third-party to lead a due diligence effort as a basis for decisions on the project.

In 2010, the ISEPA Board of Directors retained Schulte Associates LLC (SA, www.schulteassociates.com), a management consulting firm with experience in power project development, management, and permitting, in April to develop and lead an independent, third-party, and objective due diligence effort on the project. Robert H. Schulte of SA became Executive Director and Project Manager to accomplish this. SA defined the due diligence process as having three components: economics studies, site geology, and project marketing. All three components needed to be successful for ISEP to be successful.

Two test wells (Keith Well #1 and Mortimer Well #1) were drilled and pump tested. Core samples were sent to Sandia National Laboratories (SNL) for testing (see Section 9 for details).

As the result of a competitive bid process, R.W. Beck was retained and performed the "Phase I" cost and economics studies. See Section 3for details. At SA's recommendation, the ISEPA Board decided to consider other, non-public power entities as participants in the project (see Section 8 for details). Initial project marketing to potential new participants was performed (see Section 8 for details). Project transition agreements were developed between the ISEPA members to move the project from investment-based participation to Megawatt share-based participation, and to enable the addition of new, non-public power participants (see Section 8 for details). An additional $145,000 in project funding was invested by ISEPA members.

In 2011, the third test well (Mortimer #2) was completed. Core samples were sent to SNL for testing (see Section 9 for details). An additional $105,000 in project funding was invested by ISEPA members. R.W. Beck was retained and performed the "Phase II" economics studies (see Section 3 for details). Project marketing to potential new participants was continued and expanded early in the year, but later suspended when results of the geology studies indicated the outcome might be unfavorable.

Hydrodynamics performed computer reservoir modeling of the Dallas Center site including the results of the test wells. The results showed the geology of the site to be challenging because of low permeability of the sandstone storage structure. Instead of the contemplated 270 MW, the site could perhaps accommodate a smaller CAES Project of about 65 MW (see Section 9 for details). A third-party peer review of the site geology findings chartered by the ISEPA Board and performed by MHA Petroleum Consultants, based on the work by Hydrodynamics, found the Dallas Center site as unsuitable for a CAES project of any size (see Section 9 for details). The R.W. Beck Phase II report showed that a CAES project smaller than 270 MW would not be cost-effective. Based on the geology and economics results, the Project Management Team recommended to the ISEPA Board that the project at the Dallas Center site be terminated. The Board agreed and voted unanimously on July 28, 2011, to terminate the project. Project shutdown activities (capping of the test wells, restoration of the well sites, sale of project properties, etc.) were under way at the time this report was written.

The DOE's Storage Systems Program and SNL provided support for documenting Lessons from Iowa, and providing Lessons to other storage projects under development.

The public power-focused history of the ISEP project favorably affected the financials of the project, and negatively affected (i.e., limited) the market for participation. As discussed in Section 3, having public power entities as owners of the project helped the cost-effectiveness of the ISEP storage project. This happened because the financing requirements of public power entities for large capital investments are lower than the corresponding requirements of for-profit entities like investor-owned utilities (IOUs). As a result, the annual capital investment-related revenue requirements on the ISEP investment (return of and on the debt service) for a public power storage owner are smaller relative to the potential annual operating benefits of the project than they are for a for-profit owner. This makes the project benefit/cost ratio for a public power entity tend to be higher than that for an investor-owned entity for the same project. In the absence of investment tax credits (ITCs), this is generally true for any large capital-intensive utility project, not just storage.

The project was originally conceived as an effort by public power, for public power. In the early stage of the due diligence effort in mid-2010, SA advised the ISEPA members that their total need for such resources could not justify the entire 270-MW project. In fact, the ISEPA members alone could potentially justify only about 50 MW to 100 MW of the project. Additional project participants would be needed to fully subscribe the project. That meant that the project would need to approach non-public power entities for their participation. After much discussion, the ISEPA members agreed to do that.

The original IAMU participants in ISEP were municipal distribution utilities with extensive experience in distribution, but little experience in power plant project development, and this affected their ability to move the project forward until participants who had such experience joined ISEPA later. The original participants typically procured their energy resources from wholesale power suppliers through contract arrangements, or as partners in multi-owner power plants. Those wholesale power suppliers and power plant partners had provided the expertise and management to actually develop the power plant facilities themselves. This background of the original ISEP participants limited their efforts to research and development studies until the MRES and Central Minnesota Municipal Power Company power agencies joined ISEPA as members in 2009.

The ISEPA members did not own significant quantities of wind energy or transmission facilities near the ISEP project site. They also did not own significant quantities of conventional generation facilities near the site. This negatively affected their ability to evaluate and capture all of the potential storage benefits of the ISEP facility. As a result, the due diligence process determined that the ISEPA members by themselves were probably not the most beneficial owners of storage. Either they needed to secure additional project participants with the desirable characteristics, or they needed further developments in MISO markets and tariffs to realize the full value, or both. See Section 5 for more details.

3. ECONOMICS

3.1 Introduction

The results of the economics analyses are described in this section. The cost assumptions developed for the CAES project and its alternatives are also included. The economics study was performed in two phases, and both phases are detailed here.

3.2 Costs

3.2.1 Introduction

In preparation for the economics study, the ISEPA Project Team and its consultants spent considerable effort to correctly estimate the input cost assumptions. The results of the cost estimate process are described here.

Experienced utility resource planners understand that it is very difficult to get truly comparable cost figures from different alternatives from different reference sources. This occurs because there is not a standard definition of what cost elements are included in a capital cost. Accordingly, the Project Team worked to develop cost assumptions for the various alternatives on a consistent and comparable basis.

Cost assumptions for the ISEP CAES facility were based on previous work by Burns & McDonnell and Black & Veatch for the project, updated by Brulin Associates working with R.W. Beck and Dresser-Rand (D-R). Cost estimates for comparably sized conventional natural gas-fired CC and simple-cycle CT generation facilities were developed by R.W. Beck. Beck then reviewed the information for all three alternatives, and revised them as necessary to place them on a consistent basis, with similar cost elements and development assumptions. Costs were expressed in 2010$, and escalated to represent costs for in-service in 2015.

3.2.2 Lessons

Although ISEP did not choose a specific CAES technology for its project, for planning purposes the facility was assumed to consist of two 135-MW (net generation) D-R trains of CAES equipment for a total generation output of 270 MW. This project size was based on a combination of factors including the estimated size of the ISEP reservoir, the nominal total need of the project participants as viewed at the time, and the size of the standard D-R equipment offerings. Larger sizes were viewed as desirable to achieve economies of scale.

Other suppliers and configurations of CAES equipment are available in the marketplace, and the ISEP project considered several. For purposes of the study, the ISEP Project Team used D-R equipment configurations because the D-R designs were more mature, and D-R offered more solid cost estimates and assurances that were considered to be more conservative than other, less mature designs. If the project had proceeded further, ISEPA would have considered all equipment vendors and designs for the final plant equipment order.

The assumed compression (storage) cycle load for the ISEP facility was 220 MW. The ISEP CAES facility was assumed to have a split-train configuration, with separate compression and generation trains. That is, the compressor motors and generators were separate machines [13].

Although it is unlikely that the facility would be storing and generating at the same time, this assumption was used to provide additional flexibility for ISEP operation during transition from storage mode to generation mode. The two operating CAES facilities in the world use "split shaft" configurations, with a single electrical machine doing both motor and generator duties. Shaft clutches on each side of the electrical machine separate the two modes of operation at these facilities. Small improvements in operating efficiency were also gained by eliminating the clutches in the ISEP design. Splitting the trains involved additional capital cost for the ISEP alternative.

Conventional generation alternatives to CAES included a comparably sized generic natural gas-fired CC facility, and a comparably sized generic natural gas-fired simple-cycle CT facility. The CC alternative was assumed to include one General Electric (GE) 7FA combustion turbine, one heat recovery steam generator (HRSG), and one steam turbine generator, nominally rated at 270 MW [14]. The simple-cycle CT alternative included three GE 7EA combustion turbines with a total nominal rating of 270 MW.

The estimated capital cost of a 270-MW CAES facility, including equipment costs, installation labor, owner's costs and other factors described in Section 3 is about $1,374/kW (in 2010$), which is (see Table 1) about 22% higher than a comparably sized conventional natural gas-fired CC generating unit, at $1,122/kW (in 2010$); and about 83% higher than a comparably sized natural gas-fired simple cycle CT generating unit, at about $750/kW (in 2010$).

The inflation rate for costs from 2010 thereafter was assumed to be 2.4%/year [15].

The estimated employment staffing required for a 270-MW CAES unit is about 15 full-time equivalent (FTE) employees. This compares to (see Table 2) about 19 FTEs for a comparably sized CC, and about 10 FTEs for a comparably sized simple cycle CT unit.

The estimated fixed O&M cost of a 270-MW CAES unit (in 2010$) is $16.69/kW-year. This compares to (see Table 1) $19.81/kW-year (in 2010$) for a comparably sized CC, and $12.43/kW-year (in 2010$) for a comparably sized CT.

The estimated non-fuel variable O&M cost of a 270-MW CAES unit (in 2010$) is about $2.03/MWh. This compares to (see Table 1) $2.44/MWh (in 2010$) for the CC, and $2.63/MWh (in 2010$) for the CT.

The forced outage rate for the CAES facility was assumed to be 3%. This compares to (see Table 1) 2% for the CC unit, and 4% for the CT unit.

This assumption was based on Brulin Associates and R.W. Beck's judgment that a CAES unit would likely have a forced outage rate somewhat higher than a CC unit, but somewhat lower than a CT.

The minimum load of the 270-MW CAES generating unit was assumed to be about 32 MW. This compares to (see Table 2) about 159 MW for the CC unit, and about 132 MW for the CT unit.

Table 1. Facilities Modeling Assumptions (2010$) [16].

	ISEP CAES	Generic CC	Generic CT
Total Capital Cost ($/kW)	1,374	1,122	750
Generation Cycle:			
Min Capacity (MW)	32.3	158.8	132.4
Max Capacity (MW)	264.7	264.7	264.7
Air Flow @min (lb/s)	149	-	-
Air Flow @max (lb/s)	800	-	-
Heat Rate @min (Btu/kWh HHV)	4,806	7,370	9,750
Heat Rate @max (Btu/kWh HHV)	4,395	7,000	9,750
Variable O&M ($/MWh)*	2.03	2.44	2.63
Fixed O&M ($/kW-yr)	16.59	19.81	12.43
Forced Outage Rate	3.0%	2.0%	4.0%
NO_x Rate (lb/MMBtu)	0.0100	0.0100	0.0300
SO_2 Rate (lb/MMBtu)	0.0006	0.0006	0.0006
CO_2 Rate (lb/MMBtu)	119	119	119
Compression Cycle:			
Load (MW)	219.82	-	-
Air Flow (lb/s)	830	-	-
Reservoir Capacity (lb)	100,000,000	-	-
Variable O&M ($/MWh)	0.00	-	-
Fixed O&M ($/kW-yr)	0.00	-	-
Forced Outage Rate	3.0%	-	-

*Calculated based on 50% capacity factor

Table 2. Facility Staffing Plan [17].

Description	CC 1x1 Facility	SC 3X0 Facility	CAES 2x0 Facility
Plant Manager	1	1	1
Office Manager	1		
Admin Assistant/Warehouse	1	1	1
Plant Engineer	1		1
O&M Manager	1	1	1
Control Room Operator	5	5	5
Power Block Operator	5		
Instrument, Controls and Electrical Technician	2	1	2
Mechanic	2	1	4*
Total Staff	**19**	**10**	**15**

*The mechanics at the CAES Facility would take on the role of Operation and Maintenance Technician. They would work a rotating schedule for two-shift to cover the startup, operation, and shutdown of the thermal expander and perform mechanical maintenance as needed.

The ratio of kWh of electricity input in the compression (storage) cycle to generation kWh output for a 270 MW CAES unit is about 80% [18].

In addition to energy contained in the compressed air, the CAES unit generation cycle uses natural gas firing. The heat rate for the CAES unit at full load of 270 MW is 4,395 Btu/kWh. This compares to (see Table 1) [19] 7,000 Btu/kWh for the CC unit, and 9,750 Btu/kWh for the CT unit.

The environmental emissions *rates* per MMBtu of fuel consumption for the three alternatives were assumed to be similar. However, *total* emissions of the three alternatives were different because of their differing heat rates. The CAES unit enjoyed a significant emissions advantage over the conventional alternatives because of its lower heat rate (fuel consumption rate) in generation mode. However, total CO_2 emissions of the CAES alternative were also affected by the fuels used to store air in the compression mode. This happened because the cost of CO_2 allowances was reflected in the price of the off-peak power that the CAES unit purchased to compress air. If compression power came from fossil units, that entailed an off-peak CO_2 cost penalty for the storage alternative. If compression power came from wind machines, that did not entail an off-peak CO_2 cost penalty for the storage alternative.

The ISEPA members intended the CAES unit to be an intermediate generation unit (not baseload or peaking) that is capable of daily operation on weekdays of 10 to 12 hours, and has a compression cycle occurring during low electric load periods on weeknights and weekends.

One 135-MW CAES generation unit of the type contemplated in the ISEP project requires about 400 pounds per second of air input at a minimum inlet pressure of 827 pounds per square inch (psi) [20]. A 270-MW generation facility consisting of two 135-MW units would require about 800 pounds per second (see Table 1). For a 270-MW facility, this represents a requirement for about 2.9 million pounds of air per hour.[3] The 220-MW compressions stage would produce about 800 pounds per second at maximum output (see Table 1).

For planning purposes, the ISEP CAES facility had a design assumption of being capable of continuous operation in generation mode of 36 hours at full load output of 270 MW. This would require a useful storage capability of about 100 million pounds of operational air (not counting "cushion" air) in the storage reservoir at the start of each weekly operations cycle (i.e., Monday mornings). Economic modeling of ISEP in the MISO marketplace over its lifetime did not challenge this reservoir size assumption [21].

3.3 Economics Studies

3.3.1 Phase I Economics Study

"Phase I" was performed by R.W. Beck from July to December 2010, with funding provided from the DOE Energy Storage Program. Beck was selected by the ISEPA Project Team as the result of a competitive bidding process. Two additional firms were selected as subject matter experts (SMEs) to assist R.W. Beck. Brulin Associates was retained as SME for CAES

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3 (60 seconds/minute) * (60 minutes/hour) * (800 lb/second) = 2.9 million lb/hour.

equipment design and cost estimates. Customized Energy Solutions (CES) was retained to examine Midwest Independent System Operator (MISO) tariffs and business practices. The ISEP CAES facility and the conventional alternatives were assumed to operate as merchant plants dispatched against MISO locational marginal prices (LMPs), with public power ownership/financing. The LMPs were calculated based on zonal power market simulation of MISO to develop projections for Iowa Hub energy market prices, with adjustments for the nodal basis at the Grimes substation based on Security Constrained Economics Dispatch (SCED) simulation for selected years.

Other assumptions were made in this phase:

- The benefits and costs of all alternatives were examined over the 20-year time period 2015 through 2034.
- No coordination with regional wind resources was assumed.
- Compression energy was assumed to be provided from the resources operating in the MISO market when the compression stage was dispatched.
- Carbon regulation costs of $10.30 per ton in 2015 (in nominal dollars) increasing to $92.30 per ton in 2035 were included.
- A total wind energy build-out of about 23,000 MW (nameplate) was assumed in MISO over the planning period.
- Ancillary service revenues for spinning and non-spinning reserve were included. Revenues for regulation services were not included, primarily because of the difficulty in modeling this attribute with existing computer models.
- Three different planning scenarios for the future were examined Base Case, High Fuel Costs, and Lower Regional Wind Build-Out.

Both intrinsic benefits (i.e., based on average hourly LMPs) and extrinsic benefits (i.e., ability of alternatives to address future hourly price and quantity volatility around average hourly values) were calculated.

Present worth (in 2015$) $/kW values for CAES and alternatives were compared to estimated costs. Base analysis was performed using public power financial assumptions (i.e., 5%/year discount rate for present worth calculations); and sensitivity analysis performed using IOU financial assumptions (i.e., 8.7%/year weighted cost of capital discount rate), because potential additional participants in the Project may be IOUs.

3.3.2 Phase II Economics Study

"Phase II" extended the Phase I results further by examining coordination of ISEP storage with regional wind energy resources. It was performed by R.W. Beck from January to July 2011, with funding from the DOE Energy Storage Program. Potential additional benefits assessed in Phase II included the correlation of wind speed and LMPs in MISO; improving profitability of regional baseload plants; reducing cycling (and thus operating and maintenance [O&M] costs) at conventional facilities; reducing curtailment of regional wind facilities; transmission; MISO tariffs; and potential legislative incentives for storage.

Phase II determined that significant additional benefits were available to the storage option, resulting in net benefits higher than the conventional generation alternatives. But the additional benefits of storage would require innovation to achieve, as described below.

3.3.3 Lessons

3.3.3.1 Lessons from Phase I

Modeling using actual historical MISO loads and costs during the period 2007 to 2009 showed the ISEP CAES unit would have been dispatched at annual capacity factors of 32% in 2007, declining to 24% in 2009. However, the economic recession and lower natural gas prices resulted in lower capacity factors in 2010 and thereafter [22].

Modeling showed the annual capacity factor of the CAES unit in 2015 and thereafter would be in the range of 13% to 17% [23]. On average, this is equivalent to operation for five to six hours each weekday of the year. The dispatch of the CAES unit was simulated for each hour for 25 years. The modeling results showed that the operation of the CAES unit would be responsive to market prices during peak periods such as weekdays in winter and summer months when the off-peak and on-peak prices spreads were greater. The CAES unit operated less during the spring and fall months when price spreads were lower.

The intrinsic value of a resource alternative is the value typically calculated by utility resource planners for conventional electric generation facilities. The simulation used to calculate intrinsic value was based on deterministic forecast of hourly prices using average fuel prices and normal weather and load patterns. The intrinsic value of the ISEP CAES facility was found to be similar to that of the conventional alternatives.

Extrinsic value represents the option value of a resource to address future load quantity and price volatility, above and beyond the intrinsic value calculated using average hourly prices. See Figure 3. Intrinsic value represents the value of a resource calculated using average hourly prices. On Figure 3, these are shown as the solid lines representing the average off-peak and on-peak prices for a given time period. In reality, the CAES unit will respond to real-time MISO price signals, which have significant uncertainty and price volatility, as shown by the shaded "clouds" surrounding the average price.

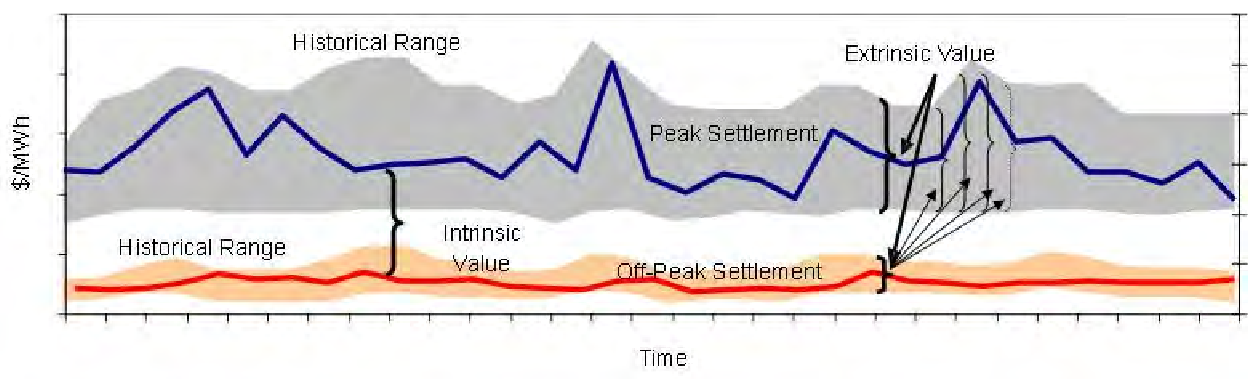

Figure 3. Illustration of the derivation of intrinsic and extrinsic values [24].

The extrinsic value was calculated based on historical volatility in MISO prices, using Black Scholes options valuation techniques, and using only hours when the unit was not otherwise dispatched for intrinsic value (to avoid double-counting) [25].

To estimate the “fair” value that the LSE may be willing to pay for such protection, it was decided to use a series of option valuations applied to the price uncertainty and label it extrinsic value. This method was used for it distinctly measures the value of volatility in excess of the intrinsic value economics of dispatch. [26]

In general the methodology suggested by Eydeland and Wolyniec (2002) [27] was used for the Forward Dynamic optimization and its approximation through a complex set of calendar spread options. The method essentially derives the value of the asset given prices of spread options with the strike prices adjusted so that the opportunities already included in the intrinsic value are not curtailed or double-counted by the implicit insurance protection;

Monetizing this extrinsic value will depend on the risk appetite by which the facility is operated. The methodology purposely does not incorporate a risk profile or operational characteristics in order to better understand the value of ISEP to an “average” investor. This therefore implies that the end-result may seem “low” for a relatively aggressive investor that is looking at a facility from a merchant perspective, but may be high for an investor that is simply not going to extract any volatility value. [28]

The extrinsic value of CAES was significantly higher than the conventional alternatives [29]. This resulted because the CAES unit could ramp fast (in both generation and storage modes), accommodate multiple starts and stops in a day, *and* store energy, and provided better insurance against future quantity and price volatility than the conventional alternatives, particularly in the storage mode that the conventional alternatives did not offer.

The magnitude of the extrinsic value of the CAES facility was found to be 59% to 119% of the gross intrinsic value of the CAES alternative in historical years 2007 to 2009 (for an average of 85% in those years) [30], and 30% to 40% of the CAES alternative’s Phase I present worth net total value depending on the case studied [31].

Extrinsic value is thus a potentially large component of an electric storage unit’s economic benefits, above and beyond the intrinsic value based on average hourly price off-peak to on-peak arbitrage, which is usually the primary focus of traditional storage economic studies.

There was internal debate among the Project Team during Phase I whether extrinsic value could actually be realized, because of the current absence of a liquid and transparent options market in MISO for such things. While the Phase I analysis valuation approach used Black Scholes options theory to define and price the extrinsic value,[4] the Project Team concluded that a storage owner did not actually need a formal options market to sell these advantages to others. They could extract most if not all of the extrinsic value for themselves.

4 In the alternative to using Black Scholes options techniques, another way to calculate this value would have been to run hundreds or thousands of Monte Carlo simulations for various price paths, based on the expected volatility of hourly prices over the planning period. The options method was a more economical way to do this estimation.

The storage unit itself, dispatched against market prices, would see the price volatility and, through its operational flexibility, be able to generate into upward price spikes (if not already fully dispatched during such times). Similarly, the compression stage would be able to take advantage of downward price volatility by storing at those times (again, if not already fully dispatched to compress during those hours). As a result, the Black Scholes analysis did not represent a requirement that an options market actually be available in order to achieve extrinsic value. Instead, it was used as a proxy for the additional value that would have been calculated if available production cost models used in the intrinsic analysis could have captured hourly price volatility, rather than using only average hourly prices. Simply stated, the intrinsic analysis using only average hourly prices tended to understate the dispatch hours of the CAES unit. Considering price volatility in the extrinsic analysis means the CAES unit would actually see wider price spreads over more hours annually, thereby causing the CAES unit to be dispatched more frequently than the intrinsic analysis alone would suggest. The term "extrinsic" here really relates to the fact that price volatility calculations were external to the standard average hourly price methods and models used that are typical of traditional utility resource planning methods. The Black Scholes method was used in the analysis as an alternative to an infinite number of Monte Carlo production cost modeling runs that would otherwise be necessary to capture the probable production cost effects of hourly and sub-hourly price volatility.

Going beyond the capabilities of the storage unit itself to achieve extrinsic value, certain types of storage owners may have additional opportunities to extract extrinsic value, depending on their specific characteristics.

A storage owner who is a Load Serving Entity (LSE) (e.g., a distribution utility with an obligation to serve its retail customers — like the ISEPA members) may be able to extract additional extrinsic value from the ability to ramp up generation (or ramp down compression) quickly when hourly sales quantities and prices are volatile upward, thereby avoiding real-time market penalties for generation scheduling shortfalls, and the ability to ramp down generation (or ramp up compression) quickly when hourly sales quantities and prices are volatile downward, thereby avoiding inefficient generation scheduling oversupply during such time periods. Simply, this is an ability to avoid being long in supply resources in a low-price environment, or short on supply resources in a high-price environment.

A storage owner who owns wind resources has the ability to ramp up compression load when LMP prices are low and wind output is high; the ability to ramp-down compression load when LMP prices are high and wind output drops; the potential ability to avoid curtailment of their wind resources; the overall improved ability to match load with wind output from their own resources, and the ability to provide regulation or ramping ancillary services (when such tariff products are available in the market).

The ideal is a storage owner who is *both* an LSE *and* owns significant quantities of wind resources.

A storage owner who was an LSE and/or a wind owner could extract the additional extrinsic value. By changing the way their resource planners plan their generation mix, relying more on the new, faster-ramping, higher-flexibility CAES to replace less flexible, slower-ramping resources. This allows them to avoid oversupplying needs with fixed generation blocks or purchases just to meet future quantity/price volatility. A storage owner could also get additional value by adjusting the way their load schedulers scheduled their daily load and generation, again taking advantage of the faster resource that also includes storage. The fast-ramping capabilities would be a new tool to help them avoid real-time price penalties that they may currently accept as a matter of "business as usual."

To the extent the storage owner could not extract the full extrinsic value by operating the storage facility to maximize their own operations, the owner could use bilateral agreements with third-party LSEs and wind owners to sell whatever surplus of extrinsic value they themselves did not need or could not realize.

Finally, an open and transparency electric options market, if available, would be useful if necessary to monetize any remaining extrinsic value not otherwise captured by the storage owners. It was recognized that the ongoing future evolution of ancillary services markets in MISO for such things as fast ramping, or a Demand Response (DR) tariff for off-peak dispatchable loads, could also realize a portion of the extrinsic value calculated in the Phase I analysis (see Section 5 for details).

Including both intrinsic and extrinsic value, the CAES unit offered higher total $/kW value than the conventional generation alternatives in all scenarios studied (see Table 3). The CAES option also has a higher capital cost, as described later in this section. As shown on Table 3, the result of the Phase I analysis was that the lifetime net $/kW present worth benefit of the CAES facility (benefits minus costs) was positive (i.e., benefits exceeded costs), and comparable to that of the conventional alternatives.

Table 3. Base Case Intrinsic and Extrinsic Value Summary for Public Power Entities [32]. (Present Worth $/kW in 2015$)

	ISEP	CC	CT
Intrinsic	1,713	1,696	1,281
Extrinsic	473	264	190
Total	2,186	1,960	1,471
Cost	1,547	1,205	805
Net Benefit	**639**	**755**	**666**

A sensitivity case (high fuel prices) was examined to evaluate the effects of higher natural gas and coal prices (see Table 4). The results of this case showed:

- The net benefits of all three alternatives increased compared to the Base Case.

Table 4. High Fuel Prices Sensitivity Case Intrinsic and Extrinsic Value Summary For Public Power Entities [33]. (Present Worth $/kW in 2015$)

	ISEP	CC	CT
Intrinsic	1,703	1,740	1,191
Extrinsic	703	373	334
Total	2,406	2,113	1,525
Cost	1,547	1,205	805
Net Benefit	**859**	**908**	**720**

- The net benefit of the CAES alternative moved closer to that of the combined cycle (CC) unit, and surpassed that of the combustion turbine (CT). This occurred because the CAES unit has a better heat rate (fuel efficiency) in generation mode than the conventional alternatives. Also, its extrinsic value becomes larger faster than the conventional alternatives as fuel prices increase.

- A CAES unit like ISEP represents a hedge against increasing future fuel prices.

To test the relationship between the assumed regional wind build-out and the economics of storage, a sensitivity case (reduced wind build-out) was performed assuming the wind build-out in MISO would be half that of the Base Case. This was not an expression of lack of faith in the assumed level of wind build-out over time. Instead, it was performed to assess how the level of wind affected storage economics.

The results of this analysis showed that a deceased level of wind build-out make storage *more* cost-effective (see Table 5). This was initially a counterintuitive result, as it was expected that less wind would make storage less valuable. Upon further review, two things effected this result:

1. Delaying/reducing the wind build-out moved the capacity value for the CAES facility earlier in time. Although wind was not provided much firm capacity value, its deferral gave the CAES unit (as well as its alternatives) more capacity value earlier.

2. Potentially more important, it was realized that the analysis probably did not capture the potential benefits of storage to the profitability of the wind machines. Any benefits of storage to the wind machines (e.g., in reducing curtailments to them) would have occurred outside the analysis, and thus were not internalized to the storage facility's benefit. This was an initial signpost that potential benefits associated with certain storage attributes were not being captured in the analysis. Although the Phase I analysis used a merchant plant perspective, conventional utility planning analyses typically have the same shortcoming. See Section 5 for more examples of this phenomenon.

Table 5. Low Wind Build-Out Case Intrinsic and Extrinsic Value Summary For Public Power Entities [34]. (Present Worth $/kW in 2015$)

	ISEP	CC	CT
Intrinsic	1,812	1,906	1,397
Extrinsic	540	330	264
Total	2,352	2,237	1,661
Cost	1,547	1,205	805
Net Benefit	**805**	**1,032**	**856**

Similar sensitivity analyses in storage planning studies to date by the MISO planning staff have yielded similarly counter intuitive results on this topic [35]. The authors believe the same factors affecting the ISEP work are at play here.

The Phase I study concluded that all three generation alternatives were economically viable in the Base Case and the two sensitivity cases [36]. These Phase I results were encouraging to the ISEPA members because the net benefit of a new generation resource is not always positive. In fact, in utility applications it is often negative, requiring the utility LSE to raise its rates (prices) to customers to accommodate the resource addition. This happens because an LSE does not have the option to do nothing (i.e., not supply the retail customer's electric needs). This utility-based perspective is different from that of an independent power producer or investor, who does not have an obligation to serve, when they look at a potential project investment. As an investment, they require the net benefits to them to be positive, or they will not do the project at all.

Although the CAES option's capital cost was higher than the conventional alternatives, there was potential that the operating benefits would be sufficient to offset that disadvantage. The ISEP members knew that Phase I did not include all of the potential benefits of the CAES unit. Thus, the Phase I results taken alone were conservative (i.e., biased against the CAES unit) [37]. The ISEPA members also knew that the innovative technology of the CAES facility (particularly the geology) represented a higher risk factor than the conventional alternatives (see Section 9 for details).

Because the basic Phase I analysis was performed from the perspective of a public power owner of the facility, a sensitivity analysis was also performed to assess the corresponding results for an IOU. An IOU has higher financing costs than a public power entity due to shareholder return requirements and taxes. For example, an 8.7% weighted cost of capital was used as the discount rate for IOUs in the sensitivity analysis. As a result, future benefits of a project look smaller in present value to an IOU than a public power entity.

Results for the high fuel cost and low wind build-out sensitivity cases were also calculated for IOUs [38]. The conclusions were similar to those for public power entities described above.

To assist the ISEPA members and new participants in evaluating storage for their own systems, Phase I included preparation of a Resource Planner's Toolkit. The Toolkit included modeling assumptions, price forecasts, capital costs, extrinsic value adders, and ISEP dispatch results in detailed form [39]. A Resource Planners Toolkit Supplement provided additional assumptions and details of the analysis in spreadsheet form [40].

3.3.3.2 Lessons from Phase II

Following Phase I, a Phase II effort was enacted to investigate additional benefits of CAES that were not considered in Phase I. Such benefits included [41]:

- Coordination of the bulk storage facility with regional wind energy resources (Phase II, Task 1) [42], including usefulness of bilateral supply contracts with wind resources to supply off-peak compression energy (and thereby create a new market for wind during time periods when it is least valuable); correlating MISO LMP prices with wind speed; reducing wind energy curtailment; enabling more wind installations than would be possible without storage; and enabling credit for storage toward state Renewable Energy Standards (RES) or federal Clean Energy Standards.
- Improved operation of other generating units (Phase II, Task 2) [43], including reduced cycling and improved capacity factors and profitability.
- Ancillary services revenues (Phase II, Task 3) [44], including regulation; fast ramping; off-peak dispatchable load (or demand response, DR) during off-peak periods to add/build load); transmission benefits of storage (Phase II, Task 4) [45], and summary of total Phase I and Phase II benefits of CAES compared to alternatives.

Phase II also examined existing MISO tariffs as they would be applied to storage, and changes that may be needed to enable storage [46]. See Section 5 for details.

Overall, Phase II determined that additional $/kW value was possible using the unique storage capabilities. But achieving these benefits would often require innovation, changes in current utility practices and MISO tariffs, legislative changes, or bilateral contracts.

Phase II, Task 1 examined the correlation with wind. At face value, some form of coordination between intermittent wind resources and a fully dispatchable load like a CAES or other storage unit implicitly makes sense. From the total market's perspective, such coordination benefits the market as a whole. However, ways of practically achieving such benefits *for the economic benefit of the storage facility owner or an individual wind owner* (and thereby motivating them to build storage, or to benefit their wind resource), particularly in an LMP market like MISO as it is currently defined, are not so obvious. For example, ignoring transmission congestion effects, a wind machine and a storage unit located near each other would see the same LMP in any particular hour. The wind machine has no economic incentive to sell its output to the storage unit instead of to the market. Conversely, the storage unit would have no incentive to buy compression energy from the wind machine instead of buying it from the market at the LMP. MISO is set up to maximize the benefits of dispatch for the market as a whole. So any unique advantages of a fully dispatchable storage load accrue to the market as a whole, not to individual wind machines or other generators. While the benefits of wind/storage coordination are seen by the market as a whole, MISO itself does not own facilities; therefore, it is not a candidate to own the storage capabilities. However, it can encourage storage by appropriate tariffs and pricing that appropriately reflect the benefit of storage to the market participants.

As a result, whether a bilateral contract between bulk storage and wind resources for compression power would be a good idea in an LMP market was a subject of internal debate among the Project Team. Two ideas where such a bilateral contract may make sense are:

1. To create a hedge option so the wind machines would not see the lowest prices during low load periods, because the storage unit would ramp up its compression load during such times. This would serve to focus the benefits of the dispatchable load of the storage on particular wind machines; rather than allow the same benefit to be dispersed to the market as a whole.
2. To demonstrate that the storage and renewables are directly contractually linked, as may be necessary to qualify the storage for credit toward state renewable energy standards or federal Clean Energy Standards. Such credit for storage itself (in addition to Renewable Energy Credits [RECs] earned by the wind machines), should be considered because storage enables more renewables to be installed.

In lieu of a bilateral contract arrangement between the storage and wind, Phase II examined the probability that the storage would be compressing when the wind is blowing.

Many things affect LMP prices in an ISO market. However, based on historical data for MISO LMP prices and wind speed/output, Phase II found that on average the wind blows more during off-peak hours (see Figure 4). Also, there is a negative correlation between MISO LMP prices and wind output in MISO. “Negative correlation” means when wind output goes up, MISO prices go down (see Figure 5). This was true for all five price hubs of MISO examined (Figure 4), and it was true for Iowa as well [47].

For comparison, a similar wind speed/price correlation was done for four Electric Reliability Council of Texas (ERCOT) zones in Texas. ERCOT currently has a higher installed wind capacity-to-load ratio than MISO does. The results showed an even stronger negative correlation between wind speed and market prices there [50]. Phase II concluded that ERCOT is probably a precursor to future effects in MISO as the wind build-out in MISO increases [51]. That is, market prices will become even more dependent on wind speed and output.

These findings suggest that there need not be a bilateral contract between wind machines and storage to demonstrate cooperative operation between them. Dispatched against MISO LMP prices, the storage will be compressing during the low-load periods when the wind is blowing. Also, wind affects MISO LMP prices, and MISO LMP prices drive CAES dispatch; therefore, wind affects CAES dispatch.

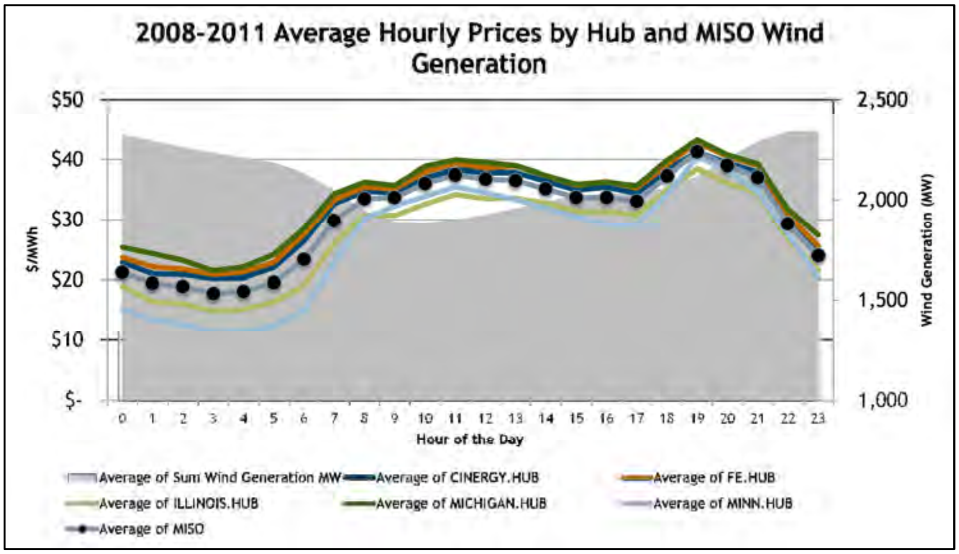

Figure 4. Average wind speed and MISO LMP prices for five price hubs in MISO [48].

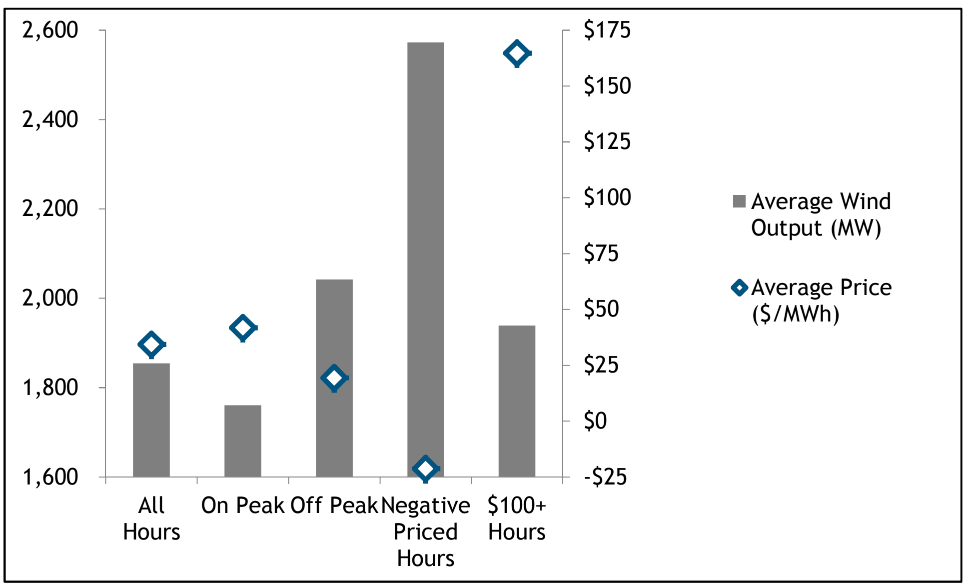

Figure 5. MISO wind output higher during off-peak and low-priced hours [49].

In theory, correlating the operation of the bulk storage facility should enable reduced curtailment of wind resources. There are two opportunities to do this:

1. If the curtailment is because of generation oversupply during low-load periods, the storage can provide additional dispatchable load to absorb the excess generation output. Phase II calculated that reducing wind curtailment in Iowa would result in a benefit of $5 million per year for each 1 percentage point reduction in such curtailment. If the storage could capture 50% of this benefit (a reasonable assumption considering the size of the ISEP storage capability), the resulting additional present

worth (2015$) benefit for the CAES unit over its lifetime would be $40/kW [52]. However, it would require a mechanism to recapture this benefit directly by the storage owner, not dispersed to the market as a whole. Either a bilateral contract with wind machines (perhaps also owned by the storage owner), or a MISO tariff that rewarded dispatchable off-peak load (i.e., a DR-type tariff, but aimed at off-peak rather than on-peak time periods), would be necessary.

2. If the curtailment was because of transmission constraints, the storage could theoretically be used to absorb the output of the wind machine during the constrained time periods. This would keep the wind machine(s) operating while keeping the output off the transmission system until the constraint was resolved, and the storage could then release the energy to the system. See Section 4 for more details.

Phase II considered the ability of a bulk storage facility like ISEP to enable additional wind resources to be installed. As such, ISEP could potentially qualify for REC values. Some precedent exists for energy storage projects to qualify for RECs, but would require state or federal legislation to implement it. ISEP may need to show its compression energy is actually provided by wind energy to qualify for RECs (e.g., a contract path back to a wind farm or other support for linkage). Assuming 25% of ISEPA's generation Megawatt-hours (MWhs) would qualify and REC value is $25/MWh (which is significantly above the current market in MISO, but representative of a robust future renewables market), the average annual revenue would be approximately $2 million. This represents a net present value (NPV) (2015$) of $37/kW for a 270-MW ISEP project [53].

Phase II, Task 2 examined the improved operation of other generating units. Phase I modeling determined that the ISEP storage unit reduced MISO system production costs by about $11 million per year by 2025, compared to no storage unit. If ISEP could capture 50% of this benefit for its owners, this is equivalent to a present value benefit (2015$) of $65/kW for a 270-MW ISEP project [54]. A mechanism necessary to capture this system benefit and focus it on the ISEP owners to help them pay for the project is not currently available. The benefit is MISO-wide, and MISO does not own facilities; therefore MISO owning the storage is not in MISO's business model. In the pre-MISO past, an individual utility would dispatch its own generation, and could thereby internalize the benefits of its own storage facilities through improved operation of its own generation system.

A literature search in Phase II identified national and regional work and concern regarding increased cycling of conventional coal generating units because of increasing penetrations of intermittent wind energy resources. This increased cycling was increasing wear and tear on such units, and the resulting O&M costs.

The Phase I modeling had determined that ISEP would reduce cycling of certain nearby coal units in Iowa. Phase II estimated that this increase in cycling represented an increase in O&M costs of $24 million per year. If ISEP could reduce the cycling by 30% (represented by ISEP's MW output compared to the total MW of coal units affected), that would be a $7 million per year savings. If ISEP could capture 50% of this savings, that would be a present value benefit of $42/kilowatts (kW) for a 270-MW ISEP project [55]. Unless the affected coal units' owner(s) also owned the storage, there is no current method for transferring these benefits to the owners of ISEP.

Phase I modeling calculated that ISEP operation in compression mode during off-peak time periods would improve the capacity factor of certain baseload generating units in Iowa by 11% to 12%. This represents an estimated potential gross margin improvement of $5 million for these units. If ISEP could capture 50% of these benefits, that would amount to an NPV benefit of $37/kW for a 270-MW ISEP unit [56]. Unless the affected baseload units' owner(s) also owned the storage, there is no current method for transferring these benefits to the owners of ISEP.

Phase II, Task 3 examined existing MISO tariffs as they would be applied to storage, and changes that may be needed to enable storage [57]. The results include:

- Current MISO tariffs do not fully recognize the value of fast-ramping resources and generally tend to undervalue Ancillary Services (AS).
- MISO is working to improve AS markets and the pricing of AS.
- Improvements could lead to additional revenue for ISEP from higher Spin and Regulation prices in particular and potential incremental value from a ramping AS product that could be introduced in the future.
- Some of the improvements in AS markets combined with other changes MISO is working on related to dispatching units in the Real Time (RT) market could reduce price volatility in the RT market.
- Since historic price volatility was incorporated in the valuation of ISEP under the Phase I estimation of Extrinsic Value, the changes under way at MISO could present at least a partial trade-off for ISEP's valuation (i.e., higher AS revenues but lower energy revenues).

This is a dynamic issue and will continue to evolve. MISO is actively investigating energy storage and existing barriers. MISO storage studies should highlight and quantify the benefits of energy storage and the existing barriers that need to be addressed. Beyond the studies, the specific rules will be critical but this will be a long process that will continue to evolve through 2012 and 2013.

Some form of off-peak dispatchable load (DR) tariff (during off-peak periods to add/build load) would be beneficial to help enable storage development. To date, most tariff and DR efforts have been focused on on-peak time periods. Little or no focus has been placed on off-peak time periods, largely because historically there has not been significant storage project opportunities that would drive the need for and discussion about such tariff developments. See Section 5 for further discussion of MISO tariffs.

Phase II, Task 4 considered the potential transmission benefits of storage [58]. As a result of this analysis, no benefits for transmission were included in the projected benefits of the ISEP CAES facility (see Section 5 for details).

The effects of greenhouse gas (CO_2) regulation were examined. It is often claimed that storage helps reduce CO_2 emissions. The statement is true if the storage enables more renewables to be built than would otherwise be built without the storage. However, the veracity of the statement depends upon the resources used for the CAES unit's compression cycle, and the resources displaced by the CAES unit's output in generation mode. In MISO, the off-peak compression energy would likely come from coal resources and wind. The on-peak resources that would be displaced would likely be coal or natural gas.

The Phase I study assumed CO_2 regulatory costs of $10.30 per ton (in 2015) to $92.30 per ton (in 2035) over the analysis period [59] (nominal $). While in an absolute sense the CAES unit was penalized for this assumption because its generation mode uses natural gas (resulting in CO_2 emissions), in a relative sense it was benefitted by it compared to the conventional generation alternatives that have higher heat rates (i.e., lower fuel efficiency). However, Phase I assumed the CAES unit would get its compression energy from whatever resources were available in the MISO market at the time. This entailed fossil-fired resources including coal. The CAES unit was further disadvantaged by the CO_2 assumption because the purchased electricity to operate the compression was assumed to be purchased at the MISO LMP, which included the pass-through of CO_2 allowance costs by the units (mainly coal) setting the marginal price in off-peak hours. When the ISEP unit was generating, the sale price of electricity at the MISO LMP also included the pass-through of CO_2 allowance costs, but on-peak the marginal unit was typically a natural gas CC plant, which has less than half the CO_2 emissions rate compared to a coal unit. Therefore, the ISEP unit's costs increase more relative to power sales due to the assumptions about CO_2 regulation. In the Phase I analysis, the off-peak CO_2 penalty to the CAES alternative was larger than its on-peak CO_2 benefit. The result in was a net CO_2 penalty overall for the CAES unit compared to conventional generation alternatives. Again, this was a Phase I result where compression energy was assumed to come primarily from coal resources. This result reverses if compression energy would come from renewable resources, as discussed below.

Given the passage of time since Phase I was performed, it is less certain that CO_2 regulation will occur, and in the magnitudes assumed in Phase I. If CO_2 regulation involving CO_2 allowances or similar taxes did not occur, removal of the off-peak to on-peak compression penalty would increase the present value lifetime benefits of the CAES unit compared to the conventional alternatives by $140/kW [60]. The off-peak compression energy penalty of CO_2 against the CAES unit, if it occurred, was bigger than the on-peak advantage of the CAES unit because of its higher generation efficiency. Whether ISEP would achieve this increase in benefits compared to conventional alternatives depends upon whether CO_2 regulation is passed, and at what $/ton cost, or whether CO_2 regulation, if any, is implemented as a direct mitigation through controls (e.g., through the Environmental Protection Agency's (EPA's) Title V and prevention of significant deterioration programs) without an allowance trading program. If that occurs, then the outcome would be the retirement of coal units and no accompanying allowance trading as was modeled in Phase I [61].

Phase II did not attempt to calculate the potential CO_2 benefit that would occur if ISEP used a bilateral contract with wind machines to supply compression energy, thereby increasing the percentage of energy that renewables contributed to its total compression energy. Instead, it was assumed that any CO_2 benefit of doing this would probably be reflected in the price for compression energy offered by the wind producer, so there would be no actual savings for the storage owner.

Table 6 summarizes the various additional benefits for the ISEP CAES facility determined in Phase II.

Table 6. Summary of Phase II Benefits of ISEP CAES Facility [62].
(Present Worth $/kW in 2015$)

Phase II Results	$/KW
MISO System Savings	$66
Baseload Unit Profit	$37
Baseload Unit O&M Savings	$42
Avoided Wind Curtailment	$40
REC Value	$37
Total	**$222**

As summarized above, the Phase II study identified potential additional benefits for the CAES option that did not apply to the conventional generation alternatives. Table 7 illustrates the total lifetime present worth benefit/cost analysis for the CAES unit and alternatives including results from both Phase I and Phase II.

Table 7. Adjusted Phase I Value and Phase II
Values for Public Power Entities 270-MW Alternatives [63].
(Present Worth $/kW in 2015$)

	ISEP	CC	CT
Intrinsic	1,713	1,696	1,281
Extrinsic	473	264	190
Original Phase I Total	**2,186**	**1,960**	**1,471**
CO_2 Penalty Removal	140		
CREB Benefit	199		
Revised Phase I Total	**2,525**		
Phase II Benefits	222		
Total Phases I and II	**2,747**		
Capital Cost	1,547	1,205	805
Net Benefit	**1,200**	**755**	**666**

3.3.3.3 Results of Phase II Analysis

The results of the Phase II analysis show that a 270-MW bulk storage unit like ISEP operating in MISO potentially offers significant benefits compared to the conventional generation alternatives, but it will take innovation, contract arrangements, and changes in MISO tariffs and legislation to accomplish it.

3.3.3.4 Potential Value of Storage

The results of Phases I and II also demonstrate that traditional utility resource planning analyses that typically examine only those benefits that were considered intrinsic value in the ISEP analysis *significantly understate the potential value of storage*. See Figure 6.

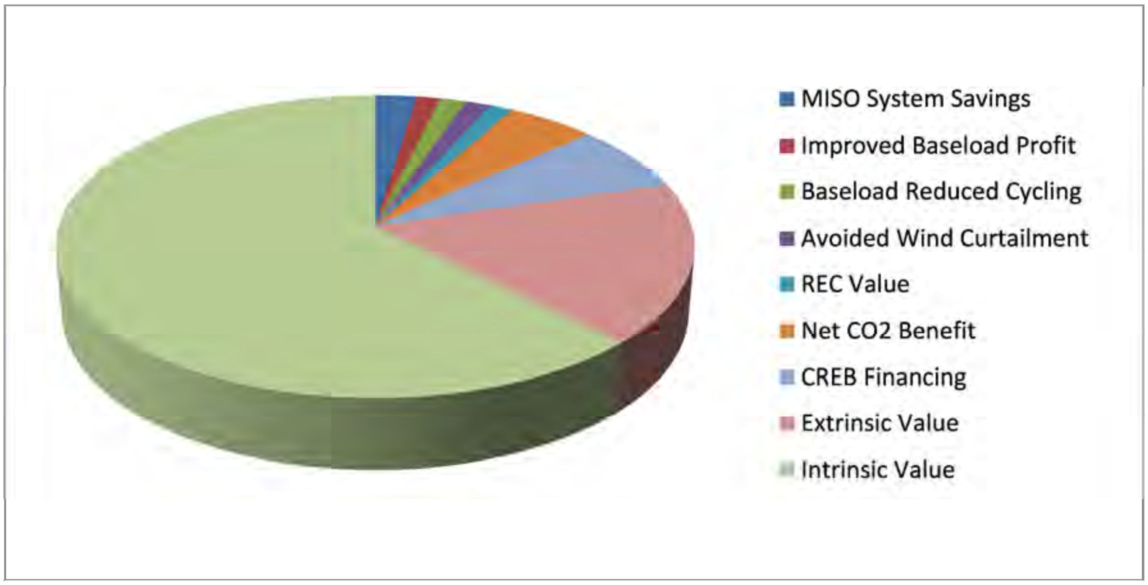

Figure 6. Estimated ISEP storage lifetime total value by component[5] (Present Worth $/kW).

3.3.3.5 Sensitivity Analyses

The results described above were for the Base Case Phase II analysis. One Phase II sensitivity analysis was also performed. Instead of a 270-MW CAES facility, Table 8 provides comparable economic results for smaller (70-MW and 135-MW) CAES facilities. These results were prepared in mid-2011 when it appeared the site geology may limit the size of the facility. As shown on Table 8, and considering the uncertainties involved in achieving the Phase II benefits, a 135-MW CAES facility would be roughly comparable in economic benefit compared to a conventional 270-MW combined cycle unit,[6] and a 70-MW CAES facility would not be cost-effective compared to the 270-MW combined cycle alternative. This happens due to lost

5 Values shown from Table 7.

6 Although capital costs for smaller CC and CT alternative units were developed, the ISEPA members considered a 270-MW CC unit to be their alternative, not a smaller one.

economics of scale for the smaller CAES unit. That is, if the entity contemplating using a storage option considers a 270 MW CC or CT unit as their practical alternative to storage, the higher $/kW costs of a smaller CAES unit would tend to make it less cost-competitive compared to the larger conventional generation alternative.

Table 8. Adjusted Phase I Value and Phase II Values for Public Power Entities CAES Units Smaller than 270 MW [64]. (Present Worth $/kW in 2015$)

$/KW	ISEP 70 MW	ISEP 135 MW	CC 270 MW	CT 270 MW	CT 53.5 MW
Intrinsic	1,713	1,713	1,696	1,281	1,281
Extrinsic	473	473	264	190	190
Original Phase I Total	**2,186**	**2,186**	**1,960**	**1,471**	**1,471**
CO_2 Penalty Removal	140	140			
CREB Benefit	199	199			
Revised Phase I Total	**2,525**	**2,525**			
Phase II Benefits	222	222			
Total I & II	**2,747**	**2,747**			
Capital Cost	2,187	1,714	1,205	805	1,451
Difference	**560**	**1,033**	**755**	**666**	**20**

4. TRANSMISSION

4.1 Introduction

The potential transmission impacts and benefits of the storage project, as determined in Task 4 of the Phase II study [65], are described in this section.

4.2 Lessons

Much has been written about the potential benefits of storage in reducing or deferring transmission investment. Although this can take many forms, it is frequently represented as a way where storage can absorb intermittent renewable energy when it is available and the transmission is constrained. This avoids placing the energy on the transmission system until a later time when the constraint is no longer present. This scenario assumes there is not a transmission constraint between the renewable energy source and the storage.

A simple example of such a transmission opportunity is a distributed storage unit (such as a battery) collocated with a wind machine "behind the (customer's or wind producer's) meter." In such a scenario, the transmission system sees the wind resource and storage as one combined resource, with no transmission constraints between them. In the ISEP example, the ISEP bulk storage facility would be located on the transmission system, with transmission facilities (and potential constraints) between the storage and the renewable energy facilities. Wind facilities in Iowa currently experience significant curtailments/interruptions because of transmission constraints in the region. By itself, this would appear to be an opportunity for storage.

ISEPA filed a generator transmission interconnection request with MISO in September 2009. In accordance with the MISO study process, ISEP was included with other proposed Iowa generation resources in the "System Planning Analysis (SPA) 2010 Iowa" group. This group included about 800 MW of wind machines, and the ISEP storage facility [66]. The SPA Iowa groups for the past three years (2008 to 2010) included more than 5,000 MW of wind machines, and the ISEP storage facility. Again, this would appear to be a storage opportunity in Iowa.

MISO issued a SPA report in May 2011 with regard to the SPA 2010 Iowa group [67]. The report concluded

- Interconnection of the SPA 2010 Iowa group of generators as MISO network resources would require high-voltage transmission improvements—primarily 345-kilovolt (kV) facilities located near the Iowa/Illinois border for exports to the East.
- The total cost of the necessary transmission improvements would be approximately $130 million, of which $20.6 million (or $76/kW based on 270 MW of ISEP output) was allocated to ISEP [68]. This figure may change in accordance with additional studies [69].[7]

[7] This network interconnection cost for ISEP was assumed to apply to any of the generation alternatives in the ISEP economics study whether ISEP, combined cycle or simple cycle. As such, these network transmission costs were assumed to offset each other between the various generation alternatives considered in the study.

- Notably for ISEP, the MISO study considered ISEP as only a generation facility that needed interconnection service. The study process did not include consideration of potential transmission benefits of matching the storage up with regional wind and other generation resources to delay or eliminate transmission.

Phase II, Task 4 of the ISEP economic study as described in Section 3 considered the potential transmission benefits of storage. In terms of network interconnection costs, R.W. Beck determined that whether ISEP were built or not, it was unlikely to affect the amount of new transmission needed for interconnection of the other SPA 2010 Iowa generation projects [70]. If ISEP were built, it would benefit the other generation projects in the SPA 2010 Iowa group because ISEP would be allocated a portion of the transmission costs that would otherwise be allocated to the other generation projects without ISEP [71].

The MISO process also identified other local transmission developments, the need for which was not affected by the presence of the ISEP generator [72]. Also, it was unclear whether ISEP could defer or eliminate the need for these transmission projects [73]. The MISO SPA study did not consider the potential benefits of the ISEP generator generating into a known load substation (MidAmerican Energy's Grimes substation near Des Moines) during on-peak load times, thereby theoretically delaying or deferring transmission investment. The MISO process is focused on generation interconnection costs, not potential savings from generator interconnections. As a result, no transmission benefits were assigned to ISEP for this cost element in the economics study.

Considering reducing wind curtailments because of transmission constraints, while this is a theoretical benefit of storage, during Phase II it was acknowledged that the transmission constraint could not be between the storage and the wind machine(s). Instead, such a benefit would be more likely if the storage and wind were both located "behind the same meter"—such as battery co-located with the wind machine. A bulk storage facility like ISEP located some distance from the wind machines may not be able to realize such transmission benefits. Also, transmission constraints can be relieved with time and money through improvements to the transmission system. Phase II realized that it would not be prudent to justify a long-term storage resource using short-term transmission benefits that may be fleeting as the transmission system continues to evolve. However, the use of storage to delay or defer transmission investments may have potential value.

Detailed assessment of the potential benefits, if any, of reducing wind curtailments because of transmission constraints in the specific case of ISEP and nearby wind machines was beyond the scope of the Phase II effort and funding. It also would require study participation by the wind project owner being affected by the curtailments and owners of the transmission facilities involved. The ISEP owners represented neither of these interest groups. As a result, no transmission benefits were assigned to ISEP in the economics study.

It is clear that the current MISO transmission interconnection study process is traditionally geared to examine costs of connecting generators on-peak. This captured the cost required in connecting the generation side of the CAES facility to the network, like any other similarly sized generating unit. There currently are no apparent provisions in the MISO process to examine the potential transmission benefits of storage limiting wind curtailment off-peak; in the past there have not been significant storage projects that drove the need for such analysis. This shortcoming needs to be addressed if significant storage development is to be accomplished in MISO.

5. MARKETS AND TARIFFS

5.1 Introduction

This section discusses actions that need to happen at the ISO level in order for a storage owner to achieve the estimated benefits.

5.2 Lessons

One lesson learned is that ownership (of the storage) matters. As described in Section 2, the ISEPA members consisted of three municipal power agencies and ten individual municipal utilities. While the ISEPA members represented LSEs, they did not own significant quantities of wind energy resources near the ISEP site. They did not own significant amounts of transmission or conventional baseload generation in the area, either. Two of the municipal agencies who were ISEPA members were MISO participants and transmission owners (TOs). The other ISEPA members were neither.

These characteristics of the ISEPA members (or the absence of them) became important during the ISEP project. The ISEP Project Team came to realize that the ISEPA members were not necessarily the ideal bulk storage owner for the reasons described in this section. When ISEPA embarked on efforts to market a portion of ISEP to new participants, in addition to looking for capacity and energy off-takers the marketing effort was focused primarily on entities who were potentially better suited to be storage owners.

A significant portion of the potential benefits of a storage facility operating in MISO are storage attributes (and potential market products) above and beyond the basic off-peak/on-peak price arbitrage available from corresponding LMPs.

In theory, a "perfect" or ideal bulk storage owner would be an entity that can internalize all the potential economic benefits of storage. In simple terms, before the MISO market such a perfect owner might be a vertically integrated utility that:

- Directly dispatches its own energy resources for the benefit of its own customers.
- Owns or otherwise has access to energy supply resources whereby the storage can experience adequate off-peak to on-peak price spreads.
- Is an LSE with an obligation to serve its customers. This means the entity's customers may be exposed to upward hourly price volatility that would benefit from the extrinsic value of storage described in Section 3.
- Owns significant wind energy resources near (within an unconstrained transmission distance of) the storage. This means the entity's wind resources may be exposed to downward hourly price volatility (or even negative LMPs) during off-peak hours that would benefit from the extrinsic value of storage described in Section 3.
- Owns conventional baseload generation resources that would benefit from increased load factors (and improved profitability) from the storage operation in off-peak hours.

- Owns conventional generation resources that are subject to increased cycling and startups/shutdowns (and increased O&M costs) because of intermittent renewables and other causes. The storage could take on this cycling burden instead.
- Is experiencing transmission constraints that may be alleviated by appropriately located and operated storage.
- Is experiencing wind energy curtailments (and thereby lost revenues) because of transmission constraints, or because of excessive generation in the area during off-peak periods when the wind is blowing.
- Wants to maximize the depth and effectiveness of its renewables portfolio.

This definition of the perfect storage owner is provided for purposes of illustration. The characteristics are all aimed at achieving the various benefits of storage described in Section 3. Few individual utilities can fulfill all of the characteristics in this simplified definition, but some utilities may have many of them. If an entity is not a perfect storage owner, then they need market mechanisms or tariffs to enable them to sell certain storage attributes to others and thereby monetize them.

Many storage benefits would occur at the ISO level. Going beyond the simplified definition of a perfect storage owner, operation in the MISO marketplace makes the search for the appropriate (if not perfect) storage owner more complicated. Unlike the simplified vertical utility example, operation in an LMP market like MISO means many of the benefits of storage are dispersed (or even dissipated) among many market participants, rather than directed specifically to the storage owner alone.

For example, the operation of storage to absorb energy during off-peak load periods would increase the load factor (and likely the profitability) of multiple baseload generation units in the region. Those profits would accrue to the owner of the baseload units, who would not necessarily be the storage owner. Similarly, the operation of storage to absorb energy during off-peak load periods would reduce the possibility of curtailment of regional wind resources during those time periods. It would also be supportive of additional wind development because it represents a new market during off-peak periods that would not otherwise exist. These benefits would accrue to the owners of multiple wind machines in the region, who would not necessarily be the storage owner. The fast-ramping capabilities of certain kinds of storage like ISEP would be useful to handle the ramping burdens currently carried by conventional generation units. If the storage took this duty, the owners of conventional generation units would experience O&M savings from the reduced cycling. But the storage owners would not necessarily see these cost benefits.

Much of the rationale for dispatching resources at the ISO level (rather than the individual utility) is to minimize energy production costs ISO system wide. As a result, operation in an ISO market means many of the potential benefits of storage are observed at the system level. However, they are dispersed among various ISO market participants who are not necessarily directly involved in providing or operating the storage.

Because much of the potential benefits of storage are observed at the MISO system level, it would seem that MISO would be the perfect storage owner. But MISO does not own facilities.

Given that, the issue is how to give an entity other than MISO incentive to own and operate bulk storage.

Short of MISO owning facilities, development of bulk storage in MISO depends upon innovation in the development of appropriate market products, mechanisms, and tariffs that recognize the potential benefits of storage and places value on them.

Just as current LMP market prices place a value on the marginal costs of energy production, transmission losses and constraints, the enactment of storage awaits development of similar market mechanisms that recognize the other dispatchability, flexibility, ramping, and option attributes (values) of that resource.

Task 3 of the ISEP Economics Study Phase II examined current and planned MISO tariffs as they may be applied to storage [74], and found that the existing MISO tariffs currently undervalue storage. In fairness to MISO, there have not been many new, large storage project opportunities to drive necessary tariff developments, so the absence of such tariffs has been largely moot.

But examination of the current MISO tariffs as they would be applied to projects like ISEP indicates that the tariffs undervalue the potential benefits of storage. Some examples include:

- MISO currently relaxes spinning reserve requirements during time periods of capacity shortages [75]. This policy undervalues all potential sources of spinning reserves, including storage.
- MISO lacks a "look ahead" capability when it develops dispatch orders [76].
- MISO procurement of regulation as a share of load is significantly low compared to most other ISOs. One possible explanation for this is the five-minute dispatch horizon discussed above [77].

The current MISO market does not feature tariffs that address all the potential attributes of and benefits that storage can provide. These benefits include fast ramping, fast cycling, and fully dispatchable off-peak loads. MISO simply has not had sufficient storage project opportunities where such products were necessary until now.

The ISEP Phase II economics study examined current MISO efforts in tariff development that may be useful for storage applications [78], [79]. These developments include:

- Development of a fast-ramping tariff [80]. This effort would be designed to help place value on fast-ramping storage resources like ISEP. The Federal Energy Regulatory Commission (FERC) has also issued a Notice of Proposed Rulemaking (NOPR) on fast-ramping resources [81]. ISEP provided comments to this FERC NOPR process [82].
- Development of improved dispatch "look ahead" capabilities [83]. This work would be designed to improve the dispatch of storage resources.
- Recent implementation of a Dispatchable Intermittent Resources (DIR) tariff. This too would be designed to further improve the dispatch of all system resources, including storage, in concert with intermittent wind [84].

- In addition to tariff efforts, MISO has begun a major storage study to be completed in 2012 [85].

ISEP believes these efforts are valuable, and suggestions for additional work follow.

Based on the ISEP experience, further development of new tariffs and mechanisms such as the following "shopping list" of potential actions is recommended:

- An ancillary services tariff that rewards fast-ramping resources (both ramp-up and ramp-down, in both storage and generation modes). One of the key beneficial attributes of CAES units (and other storage technologies as well) is their ability to ramp their output up and down, both in generation and storage modes. This is an important attribute to address and offset the variability of renewable energy resources. As noted in the previous section, MISO is already examining this topic.
- An ancillary services tariff that rewards fully dispatchable off-peak loads. In essence, this would be a DR tariff that addresses off-peak load dispatching, the converse of the traditional on-peak interruptible loads. This is a major "missing link" in ancillary service developments to date with regard to storage. Most ancillary services address dispatchable generation topics, not dispatchable load because there have not been significant new dispatchable load options proposed in MISO since the start of MISO operations.
- An ancillary services tariff that recognizes and compensates resources that can help avoid cycling wear and tear on conventional generation units. The ISEP economics study included a literature search on studies correlating increased cycling of conventional generating plants with increased O&M costs [86]. This search revealed there is significant concern in the industry about the effect of increasing levels of renewables on the cycling of conventional units. An expanded and enhanced ancillary services tariff should be considered to reimburse facilities like storage that are designed for cycling and can take the cycling burden off of conventional facilities.
- As a global solution to the issues unique to storage, MISO (perhaps with guidance from the FERC) should consider establishing storage as a class of facilities of its own (similar to generation or transmission), and then allocating cost recovery of such facilities across the entire MISO footprint, similar to the Multi-Value Project (MVP) classification recently adopted to classify transmission lines with region-wide benefits.[87]Elimination of the current MISO practice of relaxing spinning reserve requirements when resources are short, which undervalues spinning reserves when they are most needed. Review of current MISO practices showed that MISO relaxes its spinning reserve requirements when resources are short [88]. This practice reduces the value of spinning reserve, and the resources like storage that are well placed to provide it.
- To the extent the storage owner cannot harvest the full extrinsic value of the facility in other ways as described in Section 3, a fully transparent electric options market may also be necessary that enables LSEs to contract for fast-ramping generation services from storage when hourly LMPs are volatile upward, enables wind resource owners to contract for storage (load) services when hourly LMPs are volatile downward (and perhaps

negative), and enables storage to achieve its full extrinsic value, as discussed in Section 3.

As discussed in Section 3, extrinsic value was found to offer 30% to 40% of the total potential benefit for storage in the ISEP economics studies. While the storage owner may be able to internalize most of this extrinsic value without an options market if it had the right characteristics,[8] an options market, if available, would be useful to sell any residual extrinsic value the storage owner cannot absorb themselves to others. MISO itself would not necessarily need to establish such an options market. Perhaps the market could be supplied by the New York Mercantile Exchange (NYMEX) or similar entities, with authorization by MISO for operation in the MISO region and coordinated with MISO markets. In the alternative, if a "perfect" array of appropriate ancillary services tariffs was put in place that would potentially obviate the need for an options market to achieve similar levels of extrinsic value.

- A transmission interconnection study process that examines the benefits of off-peak storage to the transmission system, rather than only the interconnection requirements of the generation side of the storage resource as is done now. As discussed in Section 4, in the ISEP experience the MISO process for evaluating transmission requirements associated with interconnection of new generation developments has traditionally looked only at the new generation facility as just a generation process, with no evaluation of the potential *benefit* to the transmission system of the storage (load) phase of a generation project that also happens to include storage. This represents a missed opportunity for MISO, where appropriately located storage may provide transmission benefits and reduced or deferred transmission costs.
- A market mechanism to recognize, in monetary terms, benefits that storage may have in deferring transmission investments and making a fair portion of that benefit available to the storage owner. It is not difficult to conceptualize opportunities where storage could help reduce or defer transmission investment. For example, what if storage could be used to absorb the output of wind machines when the existing transmission system was constrained?[9] The wind output could then be released to the transmission system when the constraint was no longer present. In another example, what if the generation side of the storage facility (as in the ISEP example) would generate into a known load substation during peak load times, thereby potentially deferring the need for additional transmission into the substation?

  Some form of MISO-level monetary mechanism is necessary to enable storage to capture some of these types of storage benefit to the transmission system. Similar to other storage benefits, because the storage facility owner may not be the affected transmission owner, a way to transfer some of these benefits to the storage owner is not immediately obvious.

[8] As discussed on Section 4, the storage owner would need to be a Load Serving Entity (LSE) and a wind resource owner to internalize the extrinsic value for themselves. But they would still need an options market to monetize extrinsic value they could not use.

[9] Of course, in this example the transmission constraint could not be between the storage and the wind machines.

- A mechanism where storage investment can, at least in part, be considered as a transmission investment where storage assists the transmission system, either by deferring or obviating the need for specific transmission investments. To address the challenges described in the previous paragraph, perhaps MISO should allow a certain portion of the storage investment to be considered as transmission rate base,[10] rather than generation rate base. By doing that, the storage owner would be enabled to earn a return on its storage investment as an alternative to transmission investment.

Because traditional resource planning models used by utility planners were built to consider generation options, they do not do a good job evaluating storage. This happens because the current models:

- Do not do a good job of representing the daily, hourly, or sub-hourly dispatch of storage. Most models use an hourly dispatch algorithm, or even further simplified dispatch algorithms, in the interest of computation speed. This approach does not optimize the operation of a storage unit against off-peak and on-peak market prices.[11]
- Do not examine storage operations on a sub-hourly basis (and thus do not capture all the potential benefits of providing ancillary services). As discussed in Section 3, one of the primary attributes of a CAES storage facility is its ability to ramp its output up and down quickly—within minutes. Planning models that use only hourly dispatch cannot capture the benefits of such sub-hourly attributes.
- Do not examine the full array of potential benefits of storage to the system. As described in Section 3, storage offers benefits in terms of improved profitability of and reduced cycling wear and tear on other regional generation resources.[12] Such benefits are not captured in traditional planning analyses.
- Do not internalize the benefits of storage that accrue to individual market participants (and thus undervalue storage benefits to the system participants). Traditional planning analyses at the MISO level examine the net market cost of various alternatives. They do not examine the relative profitability to the owners of individual regional resources under various scenarios. The ISEP economics analyses show that storage not only reduces system-wide costs, it also (positively) affects the profitability of nearby resource owners whose facilities are benefited from operations of the storage.

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[10] For example, a portion of the storage investment would be included in the owner's MISO "Attachment O" as transmission investment. This would imply the storage owner would be a "transmission owner" in MISO—even though the storage owner may not own traditional transmission facilities in MISO.

[11] For this reason, in the ISEP Project Team's search for a contractor to perform the ISEP economics studies, if a contractor in its bid proposal offered to use PROMOD, a leading resource planning model, without acknowledging that PROMOD has shortcomings in modeling storage, it was grounds for immediate disqualification for the work.

[12] Increased capacity factors on and reduced cycling of regional intermediate and baseload generation resources, and reduced curtailment of regional wind resources.

Because resource planning computer models are complex, there is a risk that their results could be perceived as the ultimate answer to planning questions. Good planners know better. Models only provide additional insight into planning issues and sensitivities to various planning assumptions. When the model itself does not completely capture all the costs and benefits of an alternative, the planner needs to apply additional caution and judgment.

Bulk storage is a prime example of the need for such judgment. As noted above, traditional hourly planning models cannot capture the sub-hourly activities of a storage facility's operation. The MISO planning staff is pursuing a newer, PLEXOS™ planning model that offers sub-hourly analyses. That is a positive step. But even PLEXOS™ is not built to include consideration of all the benefits that storage can provide. One need only look at the various benefits of storage calculated in Phases I and II of the ISEP work (Section 3) to identify the things the modeling approach needs to consider when analyzing storage.

Accordingly, it is suggested that the ISO's interest in considering storage at a policy level[13] should continue to drive and demand additional improvements in the associated planning models and planning approaches. The output of traditional planning models and analyses without needed improvements should not suggest what the ISO's storage policy should be.

New or revised MISO tariffs or market mechanisms may be necessary to implement legislative initiatives promoting the integration of storage and renewables. Such initiatives are described in Section 6.

[13] It is observed that an ISO forecasting 23,000 MW or more of intermittent wind resources, as MISO is doing, should be interested in cost-effective storage of all types.

6. RENEWABLES POLICY AND LEGISLATION

6.1 Introduction

This section discusses the types of legislative actions that need to happen at the state and federal levels in order for a storage owner and the region to achieve the estimated benefits.

6.2 Lessons

There is a growing realization that renewables and cost-effective storage can be combined and coordinated into an effective combination electric supply resource for the future.

Though the storage and renewables industries in many instances have worked together in recent years, the wind industry as a whole (as represented by wind equipment manufacturers) has been reluctant to acknowledge any need for storage. This is in part because of sensitivity to the costs of renewables, which would only be increased by the cost of storage, combined with the practicality that the electric grid could accommodate initial amounts of intermittent renewables without significant impacts, and relatively few cost-effective storage alternatives existed. However, the growing contribution of intermittent renewables to the nation's energy portfolio now makes combinations of renewables and cost-effective storage increasingly important.

More recently, the American Wind Energy Association (AWEA) and the Energy Storage Association (ESA) issued a joint statement regarding the combination of renewables and storage [89]. The statement, in part, said:

> *"Energy storage provides many benefits to the power system, and the benefits associated with facilitating the integration of renewable energy are just one benefit of many."*

- Legislation or other policy initiatives are necessary to enable the full benefits of storage in encouraging renewables development. Some examples of potential legislative incentives include: Passage of the ITC and Community Renewable Energy Bond (CREB) financing provisions of the federal STORAGE 2011 Act bill sponsored by Senators Bingaman, Wyden, and Collins. This bill was a reintroduction of the STORAGE 2010 Act sponsored by Senators Bingaman, Wyden, and Shaheen [90], with provisions similar to the 2010 version. The STORAGE 2011 Act bill includes [91] a 20% ITC for investments up to $40 million per qualified storage project. Passage of this bill would have a material positive effect on the economics of storage ownership for IOU and other taxable entities interested in owning storage facilities. The analysis (Table 9) showed that passage of the ITC would have a positive and material effect on the net benefits of the CAES project for IOU owners. Similar to the results for public power entities, the results for the three alternatives were close, pending the results of Phase II.

Table 9. Base Case, Phase I Intrinsic and Extrinsic Value Summary For an Investor-Owned Utilities [92]. (Present Worth $/kW in 2015$)

	ISEP	CC	CT
Intrinsic NBITDA[14]	1,171	1,141	869
Extrinsic	335	183	136
Total Value	1,506	1,324	1,005
Capital Cost	1,547	1,205	805
Investment Tax Credit	(111)	0	0
Net Benefit	**70**	**119**	**200**

- CREB financing for public power entities interested in owning storage. CREB financing could mean a benefit to public power owners of about $199/kW [93].

Another potential legislative incentive is assigning state RECs or federal Clean Energy Credits (CECs) to the storage function itself, if the storage can demonstrate it supports renewables development and operations. As described in Sections 3 and 4, the ISEP project experience demonstrates that bulk storage like ISEP would be supportive of wind energy development in the region. This raises the possibility that the role of storage in encouraging and enabling additional renewables should be recognized in state or federal renewable energy goals and/or credits.

Using innovative ways to provide renewables credit to technologies is not without precedent. In Minnesota, for example, a number of public power entities have received allocations of hydro energy from the Western Area Power Administration (WAPA) for decades. Although the energy from this renewable resource is not eligible for application against the utilities' RES requirements, it is nevertheless deducted from the total retail energy used to calculate the utilities' RES requirements. This way, the WAPA allocations are not counted 100% against the RES requirements, but they do reduce the total RES requirements that would otherwise be necessary.

The amount of wind that would be enabled by storage was subject to considerable discussion and debate among the ISEPA Project Team and its consultants. From a simple perspective, if a 270-MW storage facility like ISEP featured 220 MW of compression, that compression load would represent a new market for regional wind machines that would not exist otherwise. Also, the market would exist during off-peak hours, when non-dispatchable wind energy was worth the least. This is a capacity-based perspective.

[14] Net earnings before interest, taxes, depreciation, and amortization.

As an alternative view, from an energy perspective 220 MW of compression load could serve a wind farm larger than 220 MW. This is possible because a wind farm does not always operate at its maximum output because of wind variation; a 220-MW storage facility could serve a larger (say, 350-MW) wind farm during hours when the farm was operating at less than maximum wind speeds. Simply, the capacity factor of the bottom 220 MW of a 350-MW wind farm is higher than the capacity factor of the 350-MW wind farm overall. This perspective, while theoretical and more complex than the capacity perspective, is nonetheless valid.

Section 3 used the more conservative (capacity) approach to assigning REC credits to storage, and assumed that only 25% of the energy stored would qualify for REC treatment. This yielded an additional present value (2010$) benefit of storage of $37/kW [94].

Proposed state legislation regarding storage and renewables include:

- California AB 2514, which directs the California Public Utilities Commission by March 1, 2012, to open a proceeding to determine appropriate targets, if any, for each load-serving entity 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, to be achieved by each load-serving entity by December 31, 2015, and a second target to be achieved by December 31, 2020 [95].
- Ohio Senate Bill 221, which would categorize storage that improves utilization of renewable resources during off-peak hours as a "Renewable Energy Resource" [96].
- Proposed legislation in Utah, which would categorize CAES projects like ISEP as a renewable energy source [97].

Another potential legislative incentive is classifying bulk storage itself as a Clean Energy Technology in any federal Clean Energy legislation, if the storage can demonstrate it is supportive of renewable energy. Another way of legislatively encouraging the function of storage in enabling renewables would be to classify qualified storage facilities as a Clean Energy Technology in any federal Clean Energy legislation. Doing this would enable qualified storage facilities to be eligible for certain incentives offered renewables.

In April 2011, ISEP participated with the Coalition for the Advancement of Renewable Energy through Bulk Storage (CAREBS, www.carebs.org), a bulk storage industry association, in submitting comments in response to a request by the Senate Energy and Environmental Committee regarding potential components of a congressional Clean Energy bill [98]. Among other things, the comments proposed that bulk storage that can demonstrate it is supportive of clean energy resources like renewable wind energy should itself be classified as a Clean Energy Technology—and thereby entitled to similar incentives [99].

Creating a market for "firm" renewable energy would be another incentive. This is where the combination of renewables and storage is used to create a renewable product with both energy *and* dependable capacity attributes. Such a combination resource could theoretically have market value above and beyond a corresponding amount of conventional, fossil-fueled capacity and energy offering similar amount of dependable capacity.

Historically, renewable energy goals and market transactions have typically been expressed in energy terms, not capacity. This happened because wind energy in particular is considered an energy resource, with little dependable capacity value, so it has been priced accordingly.

With the potential for wind/storage combinations, renewable energy can have additional capacity value made possible by the storage. As this occurs, a potential arises for a new category of market product: "firm" (or "firmed")[15] renewable energy, with its own energy *and capacity* price components. This would be analogous to "organic" vegetables being sold for a premium price at the supermarket, compared to non-organic ones.

These legislative concepts are only examples of ways storage could be encouraged in combination with renewable energy. Other concepts are certainly possible.

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[15] Depending on the dependability of the contract arrangement between the wind and the storage, the resulting combination might be "firm" like a conventional generation unit, or something less than that but more firm than the renewable resource by itself.

7. SITING

7.1 Introduction

Candidate site identification and selection for the ISEP facility represent a significant portion of the project's eight-year history (see Section 2 for details). The process of geologic work related to site selection is discussed in Section 9. This section discusses the communication and community outreach efforts related to the selected Dallas Center site.

7.2 Lessons

Due diligence demands that a storage project engage in an active and collaborative public and government affairs initiative.

In Spring 2006, it became apparent that the CAES site would be located somewhere in central Dallas County, Iowa. The probable site was located in one of the most desirable, transitional rural/suburban areas in the northwest part of metropolitan Des Moines, and gaining the public's acceptance would be difficult. Furthermore, public acceptance was made more complex by the fact that previously Northern Natural Gas had alienated many of the local residents when it purchased storage rights for its underground natural gas storage operation six miles to the west. Performing the required non-invasive seismic testing for ISEP would require the purchase of access rights from landowners and permits from Dallas County.

Members of the ISEPA Project Team realized that a strategic plan was necessary to measure and obtain the public's acceptance of the CAES project. In the teams' view, this was critical given the fact that the public had a very negative impression of storage projects as a result of its adverse experience with Northern Natural. Furthermore, obtaining approval and permits from county and municipal governments would be difficult given that history. Due diligence demanded that ISEPA have a robust public affairs and government affairs strategy.

Regarding public affairs, ISEPA engaged the services of Frank Magid and Associates of Marion, Iowa. The Magid group was a consultant to the ABC, NBC, and CBS networks, as well as several Fortune 500 companies. Working with Magid, the Project Team engaged in goal-setting and strategic planning. The public relations goal was three-fold:

1. Counter the adverse perception of the project left from the Northern Natural experience;
2. Enhance ISEPA's credibility in the community; and
3. Gain the public's acceptance and endorsement of the project.

Strategically, the goal was accomplished by identifying and measuring the public's specific concerns concerning energy supply, costs, and delivery.

When siting an underground storage project in a community, market research of the community in advance is useful. The Magid group performed a survey of the Dallas Center community to learn the residents' attitudes about energy in general and the project in particular. With regard to general attitudes about energy, the survey found [100]:

- A significantly high number of respondents (41%) felt that current household energy costs were higher than they should be.
- There was overwhelming support about the need to develop alternative energy sources.
- Only 10% of respondents were aware of the ISEP project. When asked for details about the project, most of the 10% did not know.
- After being read a description of the project, almost 60% thought it was a good idea.
- About 45% of respondents strongly supported the project idea, and 10% were strongly non-supportive. Importantly, 42% did not have an opinion.
- Of the 10% who were strongly non-supportive, the primary issue was safety of the project. Their primary issues, in descending order or importance, were:
    1. Safety/issues/dangerous for the area.
    2. I don't know enough about it/I don't know/don't understand it.
    3. Don't want it under my house/don't want it in my community.
    4. I would want more research done/sounds too good to be true.
    5. It wouldn't work/not feasible/doesn't make sense.
    6. Already have natural gas stored and I'm not comfortable with that.
    7. Cost to the county/expense.

The findings of the survey included the following recommendations to the project [101]:

- ISEPA needed to work to retain the 45% who supported the project, while convincing the 42% in the middle to support the project as well.
- Key messages of interest to the community were developed based on the Magid work. The resulting eight key talking points addressed why ISEP was a good idea:
    1. Help reduce costs/cheaper/wind is free/help control energy prices.
    2. There's lots of wind/it's something we already have/uses the wind/uses something we're not using.
    3. Decrease dependence on foreign oil/decrease dependence on foreign countries.
    4. Alternative resource/alternative source is a good idea/need to find different kinds of energy services.
    5. Healthier for the environment/clean energy.
    6. Decrease fossil fuel use, dependence/reduce our dependency on gasoline, natural gas, and other forms of energy.
    7. It's a natural source/should use the natural resources, like wind.
    8. Save energy/save resources/conserves fossil fuel/can't depend on fossil fuels forever/more efficient.

The market research firm also reviewed all project communications materials and the project website. Among other findings, it was recommended that the project reduce emphasis on building an industrial-like "plant" in the community, and choose the term "park" instead. As it turned out, the Lesson was that sometimes the simplest suggestions are the most elegant and effective. Here, Magid suggested that the public would likely view a "plant" as a purely industrial facility with all the potentially unfavorable visual and environmental aspects of such a development. Instead, following Magid's advice, the agency changed the project name from "Iowa Store Energy ***Plant***" to "Iowa Stored Energy ***Park***." The project logo became an image of stately wind machines in a bucolic scene of corn fields typical of the Dallas Center area.

Based upon the Magid study, the ISEPA due diligence team was able to formulate a successful Public Affairs program that emphasized the positive and sought to educate regarding the negative. ISEPA encountered no obstacles in obtaining access rights and local government permits for geophysical testing. When it came time to purchase property for test wells, the public support encouraged landowners to engage in a bidding process to determine who would sell or lease their property to ISEPA for testing. Government Affairs was impacted positively by the fact that city and county government and the local school district actively promoted the ISEP project.

Once market research is gathered, it should be used in real and practical ways. Based on the market research of the community, the project applied its recommendations to its operations in several ways.

- The project name was changed from "Iowa Stored Energy *Plant*" to "Iowa Stored Energy *Park*."
- The project website look and text was revised from an engineering, power-plant orientation to conform with the various important environmental reliability and energy security messages identified in the research as important to community members.
- The primary community messages were incorporated into project communication and marketing collateral materials and presentations going forward.

It is important for the project to appear credible and trustworthy in the process. The ISEP project Technical Director and Development Director spent a lot of time in the field interacting and communicating with people in the community. Although these contacts were not specifically part of the overall communications plan, they became an important asset to the project's community relationship.

Objections to a new project are often based on a lack of information. The project needs to ensure that basis for objection is minimized by substantial communication. Also, the project needs to establish a recognized and sanctioned community forum for regular communications about the project. In addition to monthly board meetings, the project established a Dallas Center community forum, chaired by the mayor. This was used to communicate and collect community input to the project.

It is useful to establish a community mailing list and use it for project updates. The Project Team established and maintained such a mailing list, and used it for project announcements and notifications of upcoming events. A project starting today would likely have a presence on Facebook or similar social networking media.

To the maximum extent possible, the decision processes should be transparent and accessible to the community affected. Project board meetings were held in the community to facilitate attendance by community members; most board meetings were held in the city of Dallas Center. The ISEPA board meeting agendas were posted on the isepa.com web site in advance of the meetings, and community members were encouraged to attend the meetings. Conference call dial-in and webinar connections to board meetings were provided so community members who could not attend in person could listen in. Community members also dialed in to board conference calls.

If possible, it is also important involve the local community in decisions about where the plant facilities will be located. Once the project's underground reservoir "footprint" had been identified by geology studies, the ISEP Project Team researched the property titles of the affected properties represented by the footprint. It was anticipated that this information would be useful later for permitting of underground storage rights with all affected property owners. More immediately, it was useful for the siting of the above-ground plant equipment and facilities.

Based on the property records, the ISEPA Project Team issued a Notice of Intent to Purchase the plant site land for the above-ground facilities. It was sent to every landowner in the project footprint. Each landowner was invited to bid on selling the land to the project. The Notice included a statement that the project had the right of condemnation for the property, but this was never necessary.

Multiple landowners submitted bids to sell their property to the project. Some bids were subsequently revised downward by the property owner when the original bid amounts were announced to the public. Although not all community members were enthusiastic about the prospect of having a power plant in their neighborhood, the bidding process resulted in some generally friendly competition among property owners for selling the plant site. The positive tone established in this process was supportive of good relations with the community throughout the balance of the project.

In the end, although it took some additional time and effort, maintaining a transparent and open decision process with ongoing accessibility to the public turned out to be the right thing to do. Although they did not necessarily agree with every project decision, the public came to know what to expect and came to respect that everything that was happening was being communicated. In fact, the Team observed that for the most part the local community was, in the end, just as disappointed in the project's termination as the owners and the Team were, and expressed that to the Team. The Lesson is simple: Projects of this nature are not by industry; industry needs to be a partner with the community.

8. PROJECT MANAGEMENT

8.1 Introduction

This section describes project management lessons learned in the ISEP project. The context is initial development from technology development to ownership development to marketing the project to potential project participants and the local community.

Project management of a multi-owner power plant project encompasses many topics. The focus of this section is on topics that relate specifically to a storage project like ISEP.

8.2 Lessons

It is a common misconception that development of a power plant involves only physical construction and operations. Instead, the initial years of development involve organizational definition and relations, market development, geology research, cost estimates, economic studies, contracts, financing considerations, and regulatory permitting. Development of a bulk storage project like ISEP takes years before a Notice to Proceed to purchase equipment and construction occurs. During the initial development phase, the project board's and Project Manager's primary job is due diligence. Before a Notice to Proceed to purchase equipment and construct the facility, these points are made regarding the Project Manager role:

- His/her primary responsibility is due diligence – enabling the project owners to make correct decisions regarding the project, including the decision to *not* construct the project.
- The Project Manager should be a qualified, independent, and objective third-party. He or she cannot have a personal vested interest in ownership or construction of the project.
- At this phase of development, the Project manager should *not* be:
  - The eventual planned construction or operations manager of the project (although such skills would be useful). The skill sets for developing and permitting a project are not always the same as constructing and operating it.
  - An employee of one of the project owners/participants. Instead, he/she should report to the project owners *as a group*. This is necessary so the Project Manager is not pressured by the interests of only one owner.
  - A developer with a personal financial interest in the project proceeding to construction. During the initial years of ISEP development, project management consisted of an ad hoc group of project team members and consultants. For lack of a designated project leader, at times the consultants seemed to be in charge of the project. In 2009, the ISEPA Board realized that they needed to designate someone to be in charge, and determined that an independent and objective Project Manager was necessary.
- The Project Manager needs to ask the right (and sometimes impertinent) questions of project staff, consultants, and geologists.
- The Project Manager should be responsible for every aspect of the project's development, and to the project's governing body for results.

A storage project needs an articulated due diligence/development plan to be successful. In the ISEP project, this plan consisted of three components:

- Economics (see Section 3 for details).
- Geology (see Section 9 for details).
- Marketing. The marketing effort consisted of contacts to and meetings with various regional public power and investor-owned entities potentially interested in becoming a participant in the project. Non-disclosure and confidentiality agreements were established with these entities to facilitate the discussions.

For a CAES project, "Geology" and "Utility" are two different languages. During the ISEP project, it became clear that geologists and utility personnel (i.e., board members) did not speak the same language. Often, the geology had to be interpreted into utility engineering and business language to facilitate communication with the board.

All prospective project owners/participants should be qualified by the project before they join it. Such qualifications include but are not limited to:

- Knowledge of what kind of resource (baseload, intermediate, peaking, renewables, etc.) they want/need.
- Ability to determine the range of MW of the project they need for their own customers.
- Ability to accommodate the project in their resource portfolio. This particularly applies to distribution utility entities with long-term wholesale contracts with other suppliers and the specific provisions of those contracts.
- Ability to economically participate in the market in which the storage will be operated.
- Ability to finance their share of the project.

The ISEPA members were not prequalified on such characteristics before they joined the project. As a result, these qualifications for some of the members had to be backfilled later as the project progressed – requiring additional ownership agreements to be negotiated among the ISEPA members while the project was in development.[16] These qualifications, or lack thereof, caused some members to withdraw.

A storage project by its nature will involve multiple and diverse participants, and this needs to be built in from the start. These would include the storage facility owner(s), transmission owner(s), wind energy resource owner(s), power purchase agreement off-taker(s), owners of conventional facilities nearby that would benefit from the off-peak load, the power market(s), and potentially others. In an open access environment, it is unlikely that all of these parties would be the same entity.

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[16] The ownership agreements included a Transition Plan, which defined the needed changes from investment-based participation to MW capacity-based participation and enabled entities other than public power to participate in the project; an Asset Sale Agreement, which sold the project from the ISEPA members to a new entity called "Iowa CAES Project"; and an Iowa CAES Project Organization Agreement, which defined the new project entity that would proceed with ISEPA members and new participants, both public power and investor-owned. These agreements were approved by the ISEPA Board in Summer 2011.

In the ISEP experience, the original ISEPA storage facility owners did not own the transmission or wind energy resources or significant amounts of conventional generation resources in the vicinity of the storage site. As described in Section 3, this represented a handicap to them achieving the various benefits of storage. The importance of these factors came to light later in the effort. In retrospect the Project Team members realized that involving a diversity of project participants earlier in the effort, rather than focusing primarily on geology alone, would have been beneficial, even though it would add complexity to the effort.

Unless the project capacity is fully subscribed from the start, its organizational structure, financing plan, and ownership contracts plan need to think broadly regarding the types of owners (i.e., public power or investor-owned) that would be eligible to participate in it. As described in Section 1, the project was originated by public power entities, for the use and benefit of public power only. Later, when it was realized that public power alone could not fully subscribe the project and investor-owned utilities would be needed as participants too, the project organization (e.g., organized as a public power agency) needed to be changed. This required the development of several organizational transmission contractual agreements among the ISEPA members to address.[17] In retrospect, it would have been better if an broad-based project organization structure had been set up from the start.

Project participation should be on a project MW output-share basis from the start, rather than only investment dollars-based. All owners' participation should be based on paying their pro-rata share of project costs, based on their respective planned shares of the plant output. In ISEPA, project participants originally joined the project on an investment basis. This investment turned out to have little relationship to each participant's actual MW need for the project. This had to be reconciled late in the project in order to determine investment responsibilities among the ISEP members for the project going forward, and to prepare to add outside parties as new participants under consistent investment rules. In retrospect, this needed to have been done at the beginning of the project.

On important issues, second opinions should be sought when there is uncertainty because of lack of data or other factors. In the ISEPA experience the uncertainty created by limited geology data (as discussed in Section 9) made the geology recommendations to proceed or not an opinion, as viewed by the ISEPA staff. Because the geology was so important and would potentially require a high level of investment in subsequent project steps, the staff was not comfortable with depending solely on the opinion of only one expert. As a result, ISEPA sought and secured a second opinion on the site geology.

Politics internal to the project owners' group or department within a single significant owner can have major consequences for a project. Consideration of the needs of all the participants is important to provide the necessary cooperation for the project to proceed.

Finally, with the benefit of hindsight, the Project Team offers the following guidance to those who may be contemplating an aquifer-based CAES project:

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[17] Ibid.

- *Project Team independence.* Future project owners would be well advised to employ as ISEPA did a due diligence project management team whose members are totally independent from individual project owners. The due diligence team should report to a committee or board representing the project owners as a group. Having multiple project owners naturally entails the potential for differing and potentially hidden agendas and philosophy that can easily result in a conflict of interest, the ramifications of which can be very detrimental. The independence of the project management team acts as a bulwark against conflicts to protect the integrity of the project's decision-making process on behalf of the project as a whole.
- *Risk assessment.* Determine, at an early stage, the owners' tolerance for risk and how that risk will be determined. It is much easier to benchmark a project against a predetermined risk standard than one which is fluid or, worse yet, non-existing.
- *Fact and opinion.* Because the critically important aquifer-based storage reservoir cannot be easily or precisely defined, project decision-making in such a CAES project will, in large measure, be based upon a combination of fact and the opinions of experts. Facts are those findings about which there is absolutely no dispute. Facts are static, and capable of being proved; opinions can differ, even when they are based on the same facts. To ensure quality decision-making we suggest that whenever reasonable, opinions be corroborated. Access to the geological expertise of SNL and the Iowa Geologic Survey as well as its contracted experts Hydrodynamics and MHA Petroleum Consultants was instrumental to the Project Team.
- *Public domain data.* Certain facts regarding the nature and size of the candidate site may exist in the public domain. It is advised to corroborate the accuracy of the data, particularly if is more historical than recent in nature.
- *Seismic data.* Non-invasive or seismic data are extremely important. However, geologists can often differ regarding seismic interpretation. One can rarely over-seismic a project. Had the ISEP had proceeded further, it is likely the project would have accomplished advanced, three-dimensional seismic to further define the reservoir and optimize locations for the production wells.
- *Core sampling.* Determining the appropriateness of an underground aquifer geological structure is always challenging. It is difficult to determine, with precision, the exact characteristics of what actually exists underground without core sampling (i.e., test wells). A CAES aquifer candidate will soon learn that "when you see one core sample, you've seen just one core sample." The characteristics of a core sample provides accurate data only as to the particular 5-inch diameter (i.e., the diameter of the test well) sample. What exists beyond the 5-inch sample is a matter of extrapolation. The further one extrapolates from the 5-inch sample without additional data, the greater the risk of missing an important geologic anomaly. Consequently, the number of and spacing between the core samples becomes very important and will form the basis for "go/no-go" decisions involving future investment of many millions of dollars. Each sample (test well) in the ISEP experience cost $500k to $700k to collect. These decisions are more easily made if the concepts of team independence, risk tolerance assessment, and opinion corroboration have already been embraced.

9. GEOLOGY

9.1 Introduction

While the site-specific geology details for ISEP may not be particularly instructive to other CAES projects in other locations, the process of securing the information should be. The Lessons for this section include a chronological list of the various geology studies performed by the project, and also includes lessons learned from the business perspective.

9.2 Lessons

9.2.1 Technical Geology Perspective

From a technical geology perspective, accomplishing the site selection and geologic analysis for a greenfield aquifer-based CAES project where there is no existing data or prior use of the reservoir time-consuming and is challenging. As an illustration, the following is a chronology of the geology studies performed for ISEP:

In 2004, Fairchild & Wells, Inc. produced a report to the Iowa Stored Energy Plant Committee, providing a review of SP27 site geology for use as natural gas and/or compressed air storage site [102].

In 2005, The Hydrodynamics Group, LLC, the primary geology consultant to ISEPA, conducted a reservoir selection study of potential CAES geological storage structures in Iowa for Electricity and Air Storage Enterprises, LLC [103]. The goals of this initial reservoir selection study were acquisition of geological data; development of high-level reservoir screening criteria; and high-level reservoir screening of geological structures. The report included comparative data for input requirements of various CAES equipment types and suppliers. The report recommended further investigation of the Stanhope Anticline and Dallas Center structures.

A study by Electricity and Air Storage Enterprises, LLC (EASE), a consultant to ISEPA, compared the infrastructure needs of three potential sites: "Alpha" (Dallas Center Dome), "Bravo" (Bagley-Herndon Anticline), and "Charlie" (Stanhope Anticline) [104].

EASE produced a report on efforts to conduct a review of potential reservoirs and locations for the ISEPA CAES facility. Based on work performed by Hydrodynamics, the report recommended further investigation of the Stanhope Anticline and Dallas Center structures [105].

EASE reported on transmission screening using load flow analyses performed by Wind Utility Consulting to examine transmission interconnection requirements for the Stanhope Anticline, Bagley-Herndon Structure, and Dallas Center Dome sites. They assumed 400 MW of peak demand impact including both wind and the storage facility's output at the same time. The study focused only in interconnection requirements, and did not attempt to replace detailed transmission network interconnection studies that will be necessary in the Midcontinent Area Power Pool (MAPP)/MISO [106].

EASE issued a report listing legal issues remaining to be addressed by ISEPA. The report addressed the structure of the project entity, project financing, joint action agency, storage rights ownership, Iowa Utilities Board (IUB) certification required, property taxes, income taxes, renewable energy tax credits, compression energy (wholesale or retail selection), and other considerations [107].

EASE developed a report on infrastructure assessment (water, highways, rail, land rights ownership, gas supply, etc.) comparing the Stanhope Anticline, Bagley-Herndon Structure, and Dallas Center Dome sites. The report recommended the Stanhope Anticline site for further assessment as most likely to support a CAES operation [108].

EASE produced a report that advanced the analysis of the previous four reports further by recommending the next steps to be taken to confirm the technical viability of the location and reservoir with the most promise for technical and commercial success based on reports and investigations to date. The report affirmed the Stanhope Anticline should be the target for seismic studies, with the Dallas Center site as a backup.

In 2006, Hydrodynamics produced a reservoir selection study examining the Stanhope and Dallas Center sites. The report was on results of seismic survey performed at the Stanhope site in November 2005. The target was the support of two 134-MWe D-R trains of CAES equipment. The Dallas Center site was chosen as the primary site, and Stanhope the secondary site [109].

EASE reported on the conclusions of seismic studies at the Stanhope Anticline. Results showed Stanhope is unsuitable for a CAES Project because it is too small and the caprock appears to be fractured. Attention turned to the Dallas Center site [110]. Hydrodynamics issued a report on the results of a high-resolution seismic survey performed at the Dallas Center site in August 2006 [111].

EASE issued a report referring to the Hydrodynamics report dated September 26, and provided a recommended technical plan for next steps in project development. EASE recommended that site modeling and the initial preparations for test wells begin, a communications plan be developed, and initial steps be taken to fulfill IUB requirements [112].

Hydrodynamics issued a report summarizing analyses of the Dallas Center site for two 134-MWe CAES units. Site modeling was performed using Northern Natural Gas' Redfield site characteristics as an analog. The report outlined multiple phases of work that needed to be done, including test wells, air injection testing, and CAES design [113].

In 2007, Hydrodynamics issued a revised edition of the September 2006 report that was the culmination of the Iowa site candidate screening analysis and selection process, a seismic reflection survey of the Dallas Center geological structure, and a CAES reservoir simulation model using the characteristics of the Redfield storage field as an analogue. The report recommended a multi-phase approach including test wells, air injection testing, and a CAES design effort [114]. The report also highlighted the key issues in doing an aquifer-based reservoir [115]:

- Water encroachment,
- Matching reservoir air pressure cycles to turbo-machinery requirements,

- Air bubble deliverability,
- Oxygen depletion,
- Oxidation issues,
- Caprock integrity, and Structure integrity with faulting.

EASE issued a report referring to and based on the findings in December 2006 and March 2007 Hydrodynamics reports. EASE recommended that ISEPA proceed with the recommendations of Hydrodynamics, and begin work securing storage leases [116].

EASE issued a report on the results of a supplemental seismic survey performed at Dallas Center in January 2007. The results modified the previous results slightly, and confirmed a dome structure at Dallas Center. EASE recommended that modeling of the site proceed using the seismic data, as supplemented, to take initial steps to drill test wells, and articulated steps for obtaining necessary IUB certificates [117].

In 2008, ISEPA requested and received from the Iowa Power Fund (IPF) a $3.2 million loan for funding the test well drilling program [118]. The Princeton Environmental Institute issued a study drawing on the results of various field tests and feasibility studies as well as the existing literature on energy storage and CAES. The report outlined the issues and framed the need for further studies to provide the basis for estimating the true potential of wind/CAES. Geologic storage in aquifers and aquifer distribution around the United States were highlighted. Several CAES projects including ISEP were discussed [119].

A review by the Iowa Geological Survey of various project reports stated the planned Dallas Center site is an "environmentally safe project," that is "well researched and planned," and the site is "a totally appropriate container for compressed air energy storage [120]."

In 2010, the first test well, "Keith #1," was accomplished at the site during April to May. Hydrodynamics issued a report on the effort on May 18 [121]. Among other findings, the report concluded:

- The top of the Mt. Simon is approximately 100 feet deeper than originally projected [122].
- The structure is more of a saucer-shaped dome, rather than a bowl.
- The structure has about 50 feet of closure, rather than 150 feet as originally envisioned. This represents an approximately 50% reduction in the air storage capacity of the vessel, compared to previous estimated performed in 2007 [123].
- Pump test results indicated a relatively low permeability of 3 milli-Darcys, but at the time this was attributed to be more representative of the cap rock materials.
- "The results of the drilling indicate additional exploratory wells will be necessary to determine the configuration of the target geologic structure [124]."

SNL completed water chemistry analysis [125], and core sample testing [126] for the Keith #1 well. These measurements indicated low permeability in the reservoir formation. The second test well, "Mortimer #1," was accomplished on the site during July to October. Hydrodynamics issued a report on the effort in November [127]. Among other things, the report concluded:

- The revised structure map indicates a saucer-shaped structure with approximately 65 to 70 feet of closure over a 1-1/2 mile area [128].
- The relatively low pump test-calculated permeability may suggest a concern.
- The known aquifer CAES reservoir properties measured at the first two test wells are "PARTIALLY" consistent with assumed properties used of the original reservoir performance analysis.
- Although the Keith and Mortimer #1 wells provided important structural control data, additional Mt. Simon exploratory monitoring wells would be necessary to confirm the structure to the confidence level required to recommend further development of this structure for CAES service [129].

Figure 7 illustrates the seismic results for the underground structure, after they were revised with results of the Mortimer #1 test well.

SNL issued a report on the Mortimer #1 core analysis on October 7, which was included at Appendix H in the Hydrodynamics November report [130]. Based on the results of the first two test wells as outlined above, there was much discussion within ISEPA whether doing a third test well was a good idea. The ISEPA Board subsequently approved a Test Well #3 effort on November 11 [131]. The third test well, "Mortimer Well #2," was accomplished on the site during the time period from November 2010 to March 2011. Figure 8 depicts the location of the three test wells, and the underground reservoir footprint relative to the town of Dallas Center, Iowa.

In 2011, because of the importance of the geology results to the overall project, the ISEPA Board in January authorized a third-party objective peer review and second opinion on the geology results and forthcoming recommendations. MHA Petroleum Consultants was retained as a result of a competitive bidding process to perform the second opinion.

In April, SNL issued a report on the Mortimer Well #2 core sample results [133]. On April 28, Hydrodynamics issued a report on the Mortimer Well #2 results [135]. Among other things, the report concluded:

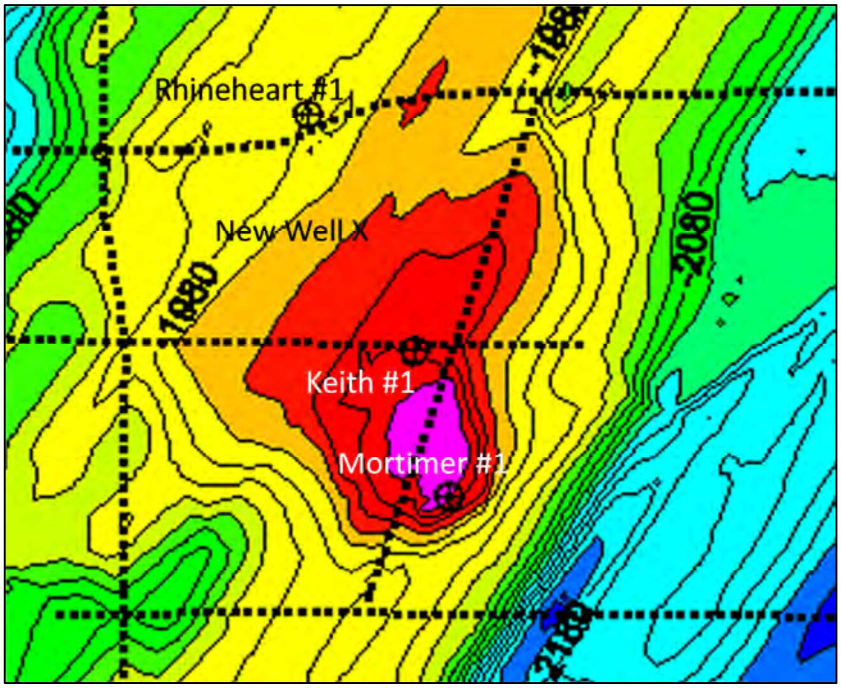

Figure 7. Illustration of ISEP reservoir structure following completion of Mortimer #1 test well [132].

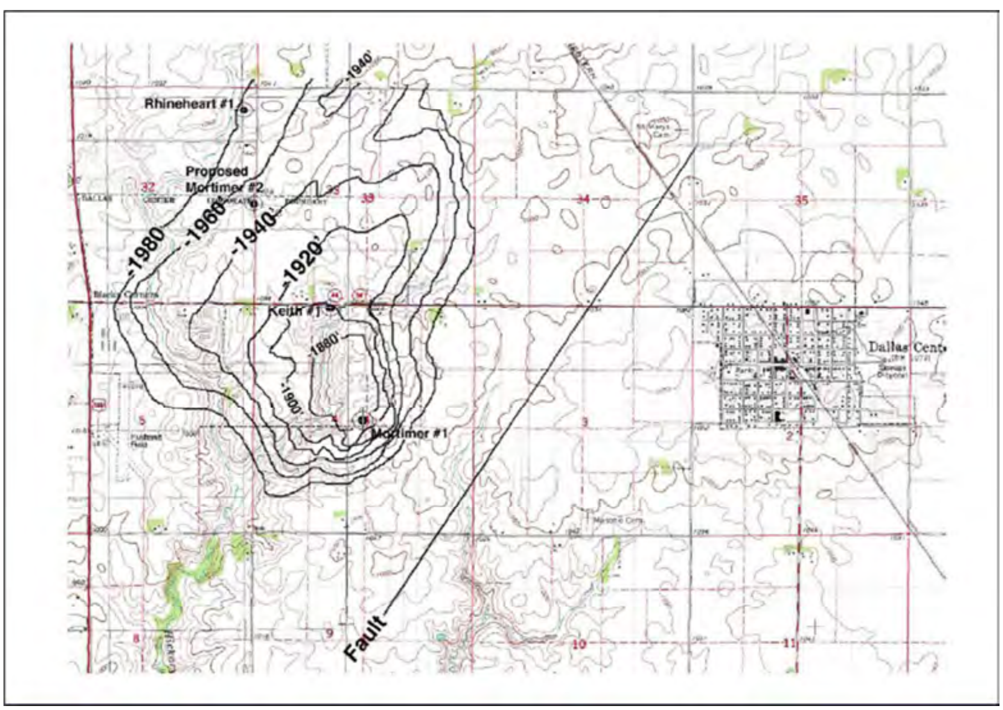

Figure 8. Location of the three test wells, the footprint of the underground structure and the town of Dallas Center, Iowa [134].

- The revised interpretation based on all three test wells is that the saucer-shaped dome has approximately 65 to 70 feet of closure over about a 1-1/2 mile square area. This represents approximately 25% reduction in the air storage capacity of the Mt. Simon air storage vessel, compared to estimates made in 2007 [136].
- The structure's porosity is 16% to 17%, consistent with original estimates.
- Low pump test results again indicate that the permeability of the sandstone was a primary concern [137].
- The water chemistry indicates a relative high concentration of sulfate that will need to be evaluated for impact on air oxygen content.

On July 22, after completing revised reservoir computer modeling, Hydrodynamics issued a final report and recommendation for the Dallas Center site, based on all work performed there and the results of the test wells. The report concluded [138]:

- The Dallas Center site geology is "dramatically different" from that found at Northern Natural Gas's Redfield site (the one originally used as an analog for Dallas Center).
- The porosity and permeability of the multiple lenses within the Mt. Simon are not conducive to simple air bubble development in a vertical direction, and represent the lower limit of reservoir permeability values for economic air production from vertical and/or horizontal wells.
- Numerical simulation studies show that a horizontal well is unable to support a 135-MW power plant because of pressure drops below the minimum operating pressure, but a 65-MW plant may be possible.
- An air injection test will be necessary to further determine the technical feasibility of developing the Dallas Center Mt. Simon for CAES:

  "5. It appears that bubble creation in this particular dual dome structure poses significant challenges that make the process ***difficult, impractical and potentially impossible*** *within the limitations of such a project." [139] (Emphasis added)*

Although not stated in the Hydrodynamics report, the cost of the additional air injection testing suggested by the report that would be required to further explore the viability of the site would entail an additional investment of $12 million to $20 million or more [140].

In July, MHA Petroleum Consultants issued their peer review second opinion on the geology results and recommendations [141]. Their report concluded:

- The Dallas Center dome location is not a suitable candidate for a CAES Project.
- The Dallas Center site has been adequately tested. Additional data (i.e., an air injection test) would not lead to a different conclusion.
- MHA recommended that project activities be ceased, and the Dallas Center site abandoned.

Project Manager SA issued its due diligence report and recommendations for the project as described in Section 8 [142]. Based on the geology findings of site limitations, the fact that a smaller CAES unit would not be cost-effective compared to conventional alternatives, and that if the project continued the next step would be a $12 to $20 million air testing effort with no guarantee of success, SA recommended with the other Project Team members' concurrence that the ISEP project be terminated. On July 28 the ISEPA Board agreed with this recommendation.

9.2.2 Business Perspective

From the business perspective of the storage facility owner, developing a greenfield, aquifer-based CAES project is challenging. The project's long-term economics (Section 3) looked favorable (assuming the geology worked). Although the geology was a negative factor, there are still some lessons to be learned from the owners' perspective.

The site identification and geology testing due-diligence process described in this section probably included the correct steps. However, extending as it did over seven calendar years, the process probably could have been done in a significantly shorter amount of time. In retrospect, the long development period was primarily driven by:

- Funding limitations, where the ISEPA members worked to leverage their own investments with funding provided by government earmarks and agencies.
- The relative complexity of developing a greenfield, aquifer-based reservoir.
- The ISEPA members' own natural conservatism when dealing with an innovative technology based on geology, a science that was unfamiliar to the ISEPA members' traditional utility business.

An aquifer reservoir is difficult to do, particularly when compared to other potential underground storage opportunities that may entail existing empty caverns, defined salt formations that can be mined, or depleted natural gas reservoirs for which some production or reservoir data are already available [143]. In the ISEPA experience, in an aquifer approach:

- The potential reservoir is unfamiliar to the non-geologist decision makers involved in pursuing a CAES project. The reservoir is a solid but porous structure thousands of feet underground that is inaccessible. It can only be conceptualized and remotely measured by seismic studies, and drilling/core sampling of test wells that cost $500,000 to $1 million each.
- The number of test wells that can be done are limited by cost, and each well, while critically useful, provides only a 5-inch-diameter vertical sample of a reservoir that in the ISEP example was more than a mile across. Cost precludes doing enough test wells to grant complete confidence of success, but perhaps only enough to test the reservoir by actually putting air in it. ISEP never got that far.
- The presence of water in the aquifer raises additional issues with regard to possible interaction of it with the air stream (e.g., oxidation of the iron in the water) and project equipment (e.g., corrosion). Because there is some water in almost all rocks underground, this issue is ever-present and may be mitigated.

While all of these issues could be addressed with the proper geology test data and project design, there is good reason why the following words appear in the "Statement of the Problem" in all three of the Hydrodynamics test well reports on the project [144]: "The use of an aquifer air storage system, like the Dallas Center structure, is problematic," and "We currently do not have adequate geological and reservoir data to determine the CAES potential of the Dallas Center Mt. Simon structure." In the ISEP experience, balancing costs and achievement of sufficient geology data to justify further project investment with a reasonable probability was an ongoing effort. Other aquifer projects would likely be similar.

Success of the project would have eventually had to rely on achievement of a reasonable comfort level with the underground geology among the utility off-takers of the plant's output. The ISEPA members, while enthusiastic during the project's development, were appropriately cautious about the geology and its critical importance to the project. In addition, multiple utilities that were involved in the ISEPA outreach effort to market the project were familiar with the above-ground CAES equipment but not with the underground geology . In the authors' view, if the project had gone forward, a communications effort would have been necessary to grant the off-takers/owners/investors enough confidence in the geology to proceed with the project. Positive geology testing results would certainly be helpful in this regard.

An innovative storage project for utility applications must contend with other, conventional generation options available to the utility off-takers that represent less technical risk and could be cheaper.

10. RECOMMENDATIONS FOR FOLLOW-ON WORK

10.1 Introduction

From the ISEP project experience and Lessons from Iowa as a whole, the authors offer the following observations and recommendations for follow-on work in bulk storage in general, and in MISO in particular.

10.2 Observations and Recommendations

10.2.1 Ownership

An entity contemplating ownership of or participation in a bulk storage project needs to consider who they are, and what kind of market they will be operating in. This affects whether they can achieve the full gamut of potential storage benefits described in Section 3 in such manner that they will be sufficiently incentivized to own and operate the storage facilities.

If the entity dispatches its own resources (as opposed to operating in a centrally dispatched market like MISO), to achieve the full value of storage the entity ideally either needs to be an LSE that owns renewable resources, or have contractual relationships with other entities with those characteristics. Also, they would have to consciously adjust their system resource procurement and day-to-day resource scheduling activities to take full advantage of the unique things the storage facility can do.

If the entity is in a centrally dispatched market like MISO, the ISO needs to have sufficient tariffs and other market mechanisms in place to enable the storage owner to achieve the full value of the benefits available from all of the storage facility's attributes. In the absence of such tariffs and market mechanisms, many of the potential benefits of the storage facility will go un-monetized, or will accrue to the benefit of market participants other than the storage owners.

10.2.2 Economics

Off-peak to on-peak price spread arbitrage is often considered the primary potential economic benefit of a bulk storage unit, but the ISEP experience and studies show it is not the only one. Accomplishing bulk storage will require the tapping of the full range of storage's attributes, benefits, and value:

- Off-peak to on-peak price arbitrage (intrinsic value).
- Option value to address price and quantity variability (extrinsic value).
- Fast startup, multiple daily startups/shutdowns, and fast ramping (ancillary services).
- 100% dispatchability of off-peak load (to improve capacity factors and reduce cycling of conventional plants, and reduce curtailment of renewable resources).
- Ability to enable more renewable resources than could be accomplished without storage.
- Transmission deferral.

A storage owner or participant must be ready and capable to innovate if they hope to achieve the full benefits of such a project. As described in Section 5, many of the necessary market mechanisms to enable storage do not currently exist.

10.2.3 MISO Markets and Tariffs

The ISEP project was focused on future operation in the MISO market. Although specific market operating rules vary among the various ISOs, the conceptual lessons-learned about what it takes to make bulk storage happen in MISO would likely apply to other ISO markets as well.

MISO is working on various storage studies and tariffs.

The MISO efforts need to result in tariffs that can enable the full range of beneficial storage attributes and full value of storage for the storage owners and the MISO region as described in Sections 3 and 5. This would include ancillary services tariffs, and coordination with various legislative initiatives providing incentives for additional renewables (and related storage) development. If storage owners cannot otherwise achieve the full extrinsic value of their facilities, creation or participation in an electric options market would be useful.

Another market concept that deserves consideration is the creation of a market product involving "firm" or "firmed" renewable energy, with both energy and capacity components. Historically, renewables have been thought of as primarily an energy resource because it is intermittent. Combinations of renewables and storage could provide renewable energy capacity value. This combination should be valued and priced as a premium product compared to conventional energy sources, similar to organic produce sold in supermarkets.

As described in Section 5, existing computer resource planning models do not do a good job calculating the potential benefits of storage. MISO is working on improved modeling techniques, but more improvements need to happen before the models. In the meantime, the authors suggest that MISO policy toward encouraging storage, particularly to address increasing levels of intermittent renewables on the regional system, should drive modeling improvements, rather than modeling shortcomings suggesting MISO storage policy.

It is recognized that from a practical perspective, MISO probably needs a specific new proposed bulk storage project of material scale that would help drive the need for proved tariffs, markets, and planning models. Doing such development in the abstract without an actual specific project to focus on is difficult, and would probably be (rightfully) assigned a low work priority.

10.2.4 Legislation

The need for storage is growing, at least in part, as a result of legislatively driven incentives for renewable energy development, and for the same reasons storage should be similarly encouraged by legislation. Simply, storage enables existing renewables (and other resources) to operate better, and it enables more renewables to be built than could be accomplished otherwise.

Legislation at the federal level for storage should include:

- Passage of the STORAGE 2011 Act or something similar, including ITCs for investor-owned bulk storage owners and CREB financing for public power entities.
- If a national RES or Clean Energy Standard is passed, then bulk storage that demonstrably enables renewables operation and development should itself be classified as a renewable or clean energy resource, and thereby eligible itself for RECs or CECs.

Legislation at the state level for storage should include:

- Recognition of the role of bulk storage in enabling renewables development and achieving state RES.
- For those bulk storage facilities that demonstrably enable renewable operation and development, their storage energy should be, in whole or in part depending on the project-specific circumstances, credited against the owners' state RES requirements and eligible for RECs of their own.

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MacIntosh Compressed Air Energy Storage Facility

110 MW

Compressed Air Energy Storage (CAES)

The world's first and only utility-scale compressed air energy storage facility in the United States. Along with Huntorf CAES in Germany, the only (2) operational commercial CAES plants in the world.

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The MacIntosh unit captures off-peak energy at night, when utility system demand and costs are lowest. Compressors force air into an underground storage reservoir at high pressure. With the ability to come online in under 14 minutes, PowerSouth uses the stored energy during intermediate and peak energy demand periods to generate electricity. At full capacity, the CAES facility produces enough electricity to power approximately 110,000 homes. The CAES plant burns roughly one-third of the natural gas per kWh of output compared to a conventional combustion turbine, thus producing only about one-third the pollutants.

Based on the first commercial plant ever built in Huntorf, Germany, the Electric Power Research Institute's design stores compressed air in a solution-mined salt dome in Alabama. They created a geological pocket 900 feet long and up to 238 feet wide in the dome by pumping water into it to dissolve the rock salt. When the (briny) water was pumped back out, the salt resealed itself resulting in an air-tight container.

Location:	MacIntosh, Alabama
Date Commissioned:	1991 (construction : 30 months)
Rated Capacity:	110 MW over 26 hours
Annual Production:	N/A
Cycle Efficiency:	54%
Carbon Offset:	N/A
Owner:	PowerSouth Energy Cooperative (designed by Energy Storage Power Corporation)
Generation Offtaker:	PowerSouth Energy Cooperative
Generation Technology:	Diabatic CAES. 580,000 cubic meter salt cavern.
Cost:	$65 million (in 1991, about $591/kW or about $800/kW in current dollars)

APPENDIX E – OTHER STORAGE TECHNOLOGY DATA

Flywheel Energy Storage Lives On at Beacon Power

An update on Beacon, emerging from bankruptcy to work the frequency regulation markets

Eric Wesoff

May 31, 2013

The DOE loan program had its obvious big losers (Solyndra), its seemingly big winners (Tesla), and firms like Beacon Power, which are still works in progress.

Beacon is a builder of flywheel-based energy storage for frequency regulation markets. The IEEE defines regulation as "a zero-energy service that compensates for minute-to-minute fluctuations in total system load and uncontrolled generation."

It's a market in which an energy storage service provider such as Beacon has an advantage because of the rapid response that flywheel technology can provide. Frequency regulation is known as an ancillary service and it's a market in which flywheel energy storage has a real monetization value.

In 2010, Beacon won a $43 million DOE loan guarantee.

The company declared bankruptcy in 2011.

In 2012, its assets, including a 20-megawatt energy storage plant in New York, were bought by private equity firm Rockland Capital for $30.5 million in cash, along with “additional guarantees and funding obligations to DOE of $6.6 million.”

Now Beacon Power LLC maintains the operations of Beacon’s 20-megawatt grid frequency regulation facility in Stephentown, NY, which has been delivering frequency regulation services since early 2011. Beacon is also developing a second 20-megawatt flywheel regulation plant in Pennsylvania.

Barry Brits, the CEO of the reborn Beacon Power, spoke at last week's Energy Storage Association meeting.

He noted that the 20-megawatt Stephentown facility in New York "boasts 200 flywheels operating in parallel to provide 20 megawatts of up-regulation and 20 megawatts of down-regulation in immediate response to the ISO’s AGC [Automatic Generation Control] signal." The plant has been in commercial operation for two years and has provided more than 250,000 megawatt-hours of frequency regulation service.

Brits notes, "We have also seen a very high full charge/discharge cycle requirement on the resource to match the aggressive ramping requirement of the NYSIO. Approximately 4,000 full charge and discharge cycles were seen in the first year of operation. It is the flywheel’s low cost per cycle, performance and durability that provides the basis for strong project economics."

The 20-megawatt Hazle Township project in Pennsylvania is located in the PJM market. Construction started in December.

There are currently 120 foundations on site, interconnection is progressing and flywheel deliveries begin next month. Brits noted that the capex for this project has dropped by approximately $10 million compared to the Stephentown project, and the firm expects further cost reductions.

Both of the above resources are paid for by providing frequency regulation service to the relevant ISO. The Massachusetts facility also receives payment for Alternative Energy Credits. Beacon uses a "build, own, operate and transfer" business model.

Brits said that Beacon is expanding with "active project development in California, PJM, ISO-NE and Midwest ISO." He noted flywheel technology's "ramp rate, use of the full depth of discharge as often as needed, very high cycle life, and no-degradation through the long life of the asset."

The CEO said that the new projects are enabled by FERC order 755, a ruling from the Federal Energy Regulatory Commission (FERC) to substantially increase the value that Beacon's flywheel plants can earn for their services. That ruling calls for the country's interstate grid operators to institute market systems that pay more for "fast" responding sources like flywheels and batteries than for slow, fossil-fueled power. It's a pay-for-performance tariff.

Given a second chance at the market and helped out by FERC 755, Beacon is taking another run at commercializing flywheel technology and using fast energy storage to compete in frequency regulation markets. The firm was acquired by private equity investors Rockland Capital, which is in the business of "optimizing" companies with the expectations of yielding "competitive risk-adjusted returns."

Other flywheel energy storage companies include Active Power and Flywheel Energy Systems.

Tags: bankrupt, batteries, beacon power, demand response, doe, energy efficiency, energy storage, investors, loan guarantees, smart grid, solyndra, tesla, utilities, venture capital

Flywheel Energy Storage System

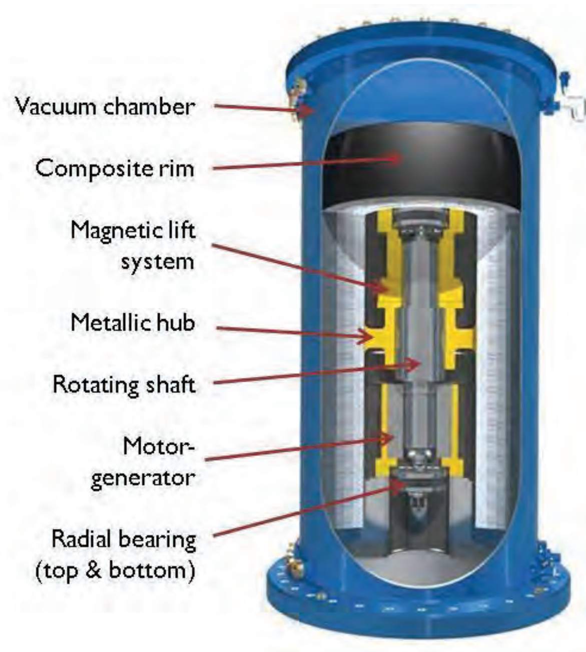
Features

- Beacon's proven Gen 4 flywheel energy storage technology
- Modular FESS implementation to meet specific needs
- High cycle life. 100,000 cycles at full depth of discharge
- Four quadrant inverter can deliver real and reactive power

Primary Applications

- Frequency regulation
- Frequency response
- Solar PV & wind output smoothing
- Power quality and voltage support
- Peak shaving

Generation 4 Flywheel



FESS Ratings*

Configuration	**Power & Energy**	**High Power**
Capacity per flywheel	100 kW	150 kW
Energy delivery per flywheel	25 kWh	12.5 kWh
Discharge time at rated capacity	15 minutes	5 minutes

** Can be configured for any power and energy value in between*

Advantages	Benefits
High performance: Less regulation needs to be purchased. Existing resources can operate more efficiently. Enhances renewable integration	• Lower cost to load for regulation and energy • Less emissions to the environment • Lower existing unit maintenance costs
High cycle life: 100,000 equivalent full charge/discharge cycles over a 20 year design life	• Low cost: $/MW per full charge-discharge cycle • High availability and limited O&M scope and cost • Reduced life cycle costs
No degradation: Energy storage capacity and performance does not degrade with cycle duty, depth of discharge, charging rate, time or temperature	• No decrease in performance over asset life • No need to oversize the system
Flexible: Capable of charging as fast as it discharges and switching power direction almost instantaneously	• Increased system availability • More frequency regulation mileage available
State-of-charge is accurately known at all times	• Predictable operation
State-of-health monitoring system	• Key parameters continuously monitored • Condition-based maintenance
No direct air emissions, no air permits or water use. NEPA evaluation: "Findings of No Significant Impact"	• Rapid siting

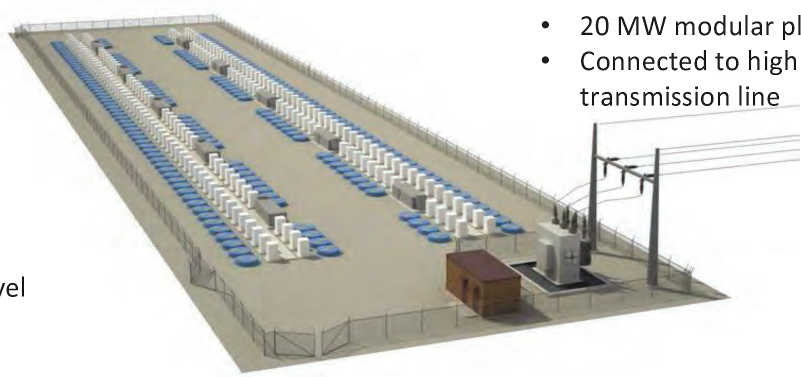
Specification	Value
Design Life	20 years or 100,000 full depth of discharge cycles
Electrical Interface	
Input / Output Voltage	480 VAC
Input / Output Real & Reactive Power	Up to 150 kVA continuous power at any power angle
Frequency	50 Hz or 60 Hz
Standby Loss	0.03 MWh / MW / hour
Round Trip Efficiency	85 %
Response Time	<1 second to full power
Mechanical	
Flywheel Rim Material	Comingled carbon and E-glass fiber composite (patented)
Flywheel Motor / Generator	Permanent magnet synchronous
Flywheel Magnetic Lift System	Combination of permanent and electro magnets
Flywheel Vacuum Level	<1 Millitorr
Flywheel Operating Rotational Speed	8,000 to 16,000 RPM
Flywheel Dimensions	82 in (208 cm) height x 47 in (120 cm) diameter
Modular Electronics & Cooling Dimensions	40 in (101 cm) x 40 in (101 cm) x 60 in (152 cm)
Environmental	
Temperature Range	-35C to +40 C
Humidity	Up to 95% (non-condensing)
Flywheel Installation	Below ground in concrete housing
Seismic Capability	Sds 2.0g Per IBC 2012
Noise Level	45 dBA standard and Ldn of 50 dBA
Communications and Monitoring	
Driving Signal	Receives DNP3 (or other standard protocols) signal from the operator. Or self managed based on frequency
Monitoring	Internet based in compliance with NERC Standards
Data Storage	Full trending and analysis. Data stored locally and offsite
U.S. Patents	
6,710,489; 6,747,378; 6,817,266; 6,824,861; 6,852,401; 6,884,039; 6,959,756; 7,034,420; 7,174,806; 7,365,461; 7,679,247; 8,008,804; 8,314,527 (other U.S. and international patents pending)	

Flywheel assemblies arriving at a plant site

Integrated power and control electronics and ancillary equipment

Typical Installation

- 20 MW modular plant
- Connected to high voltage transmission line



System Characteristics

- No direct fuel or emissions – typically permitted locally like a substation
- Unmanned installation, remotely operated
- Modular design results in high availability
- Can be sized from 100 kW to any power level

FOR IMMEDIATE RELEASE

Beacon Power Installs First Flywheels at Pennsylvania Energy Storage Plant

Officials cite benefits for improved grid stability and renewable energy expansion at commencement ceremony

Tyngsboro, MA and Hazle Township, PA – June 21, 2013 – Beacon Power, LLC, the world's leading manufacturer of grid-scale flywheel energy storage systems, was joined today by federal, state and local officials at a ceremony in Hazle Township, PA, signaling the start of flywheel installations and full-scale construction for the company's 20-megawatt (MW) flywheel energy storage plant at the site.

Attendees and speakers at the event included U.S. Congressman Lou Barletta – Pennsylvania 11th District; Dr. Imre Gyuk – Program Manager for Energy Storage at the U.S. Department of Energy; William Goldsworthy – Deputy Director, Pennsylvania Governor Thomas Corbett's Northeast Regional Office; State Senator John Yudichak; State Representatives Tarah Toohil and Mike Carroll, and Commissioner Wayne Gardner – Pennsylvania Public Utilities Commission.

"Flywheel systems promise to be an efficient and cost-effective way to provide frequency regulation," said Imre Gyuk, head of energy storage for the U.S. Department of Energy. "DOE is proud to have taken part in the development of this technology from the very beginning. Flywheels will become an important tool in assuring the resiliency and stability of the grid."

"Pennsylvania has an impressive array of abundant energy resources, matched by our commitment to use these resources both smartly and efficiently," said Governor Tom Corbett. "Today's event is an exciting and important step, helping to enhance our electric grid's security and reliability in a manner that helps lower costs to consumers."

Attendees at the commencement ceremony witnessed installation of the first of the plant's 200 flywheel modules. The first 4 megawatts (MW) of energy storage are scheduled to enter commercial operation in the PJM Interconnection grid system in September, with the full 20 MW plant operational during the 2nd quarter of 2014.

"PJM continues to welcome new technologies that provide diversity to the asset mix in PJM, as well as an opportunity to provide frequency regulation service," said Terry Boston, CEO and president of PJM Interconnection. "This will be the first flywheel technology placed into our regulation market."

Flywheel Energy Storage and Frequency Regulation

Frequency regulation is an essential grid reliability service that is performed to correct short-term unpredictable imbalances in electricity supply and demand. On the power grid, supply of electricity must match demand to maintain frequency at 60Hz. Beacon's 20 MW flywheel plant provides frequency regulation services by absorbing electricity from the grid when there is too much, and storing it as kinetic energy. When there is not enough power to meet demand, the flywheels inject energy back into the grid. These cycles can occur multiple times in time periods as short as one minute.

The Beacon flywheel facility provides a fast, accurate and reliable response to grid changes that system operators need to increase system efficiency and power quality. Furthermore, flywheels offer a long asset life with no degradation of performance, as well as the ability to move energy in and out of the grid many more times than other technologies, which contributes to low life-cycle cost and high-quality service. To date, Beacon's flywheels have accumulated more than 3.5 million operating hours.

Barry Brits, Beacon president and CEO, said, "We are excited to be moving forward with another commercial installation that showcases the performance and durability of our flywheel energy storage systems in providing frequency regulation service. Customers in Pennsylvania and other electricity users in the PJM Interconnection will benefit from greater overall system efficiency and lower costs. In addition, since flywheels recycle surplus electricity to maintain power quality and stability on the grid without burning fuel or producing greenhouse gases, the Hazle facility also contributes to a cleaner environment."

About Beacon Power, LLC

Beacon Power provides flywheel-based energy storage solutions for large-scale grid-connected facilities and smaller micro-grid and distributed off-grid applications. Services include frequency regulation, voltage support and integrating renewable energy resources. The company has the largest composite flywheel in commercial operation at 25 kWh, and the largest operational grid-tied flywheel energy storage facility at 20 MW (located in Stephentown, NY). Beacon's headquarters and manufacturing facility are in Tyngsboro, Massachusetts. For more information visit www.beaconpower.com.

About Rockland Capital

Rockland Capital, a private equity firm founded in 2003, is focused on the acquisition, optimization and development of companies and projects in the North American power sector. The firm manages Rockland Power Partners and Rockland Capital Energy Investments and has offices in Houston and New York. For further information visit www.rocklandcapital.com.

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Note: Photos and illustrations available upon request.