PACIFIC POWER
A DIVISION OF PACIFICORP

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November 19, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive SW
P.O. Box 47250
Olympia, WA 98504-7250

Attn: Steven V. King
Executive Director and Secretary

Re: Docket No. UE-120416—2013 Integrated Resource Plan

Dear Mr. King:

PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company) presented its 2013 Integrated Resource Plan (2013 IRP) at the Open Meeting of the Washington Utilities and Transportation Commission (Commission) on October 3, 2013. At the Open Meeting, the Commission requested additional information about energy efficiency by state, the Company's research into anaerobic digester biogas systems, the Company's position on Smart Grid, and energy storage. PacifiCorp submits this letter in response to the Commission's request.

A. Energy Efficiency by State

Through the first ten years of the planning period, the preferred portfolio in PacifiCorp's 2013 IRP is primarily comprised of firm market purchases and energy efficiency resources. By 2022, two-thirds of projected load growth is met with incremental energy efficiency resources. The table below shows energy efficiency as a percentage of load growth through 2022 by state.

STATE	2022
California	141%
Idaho	41%
Oregon	73%
Utah	46%
Washington	100%
Wyoming	24%
Total System—Cumulative	**67%**

B. Anaerobic Digester Biogas Systems

During the portfolio development process in the 2013 IRP, PacifiCorp allowed for the selection of combined heat and power (CHP) resources. This class of resources includes both industrial biomass systems and anaerobic digester biogas systems. The levelized cost and resource potential assumptions used for these resource alternatives were developed by Cadmus Group, Inc., an independent consulting firm. These data are summarized in a technical memorandum provided as Attachment A.

The 2013 IRP preferred portfolio includes 0.2 MW and 0.16 MW each year of anaerobic digester biogas systems in Utah and Wyoming, respectively, beginning in 2013.

C. Smart Grid

In accordance with WAC 480-100-505, PacifiCorp submits a smart grid report to the Commission every even numbered year. Along with other smart-grid-related information, the smart grid report summarizes the results of a smart grid financial model that includes costs and benefits that would be realized for a six-state comprehensive PacifiCorp smart grid deployment. The analysis includes smart-grid-related technologies that PacifiCorp believes will benefit customers and increase system efficiencies. Though the analysis currently shows a non-positive business case for a six-state smart grid deployment, PacifiCorp does review smart grid niche projects and has moved forward on projects if there is a viable business case or business reason to do so. PacifiCorp last submitted its smart grid report to the Commission in 2012 and will file an updated report September 1, 2014. The 2014 report will include information on the progress of any smart grid technologies scheduled for implementation as stated in previously filed reports and any new smart grid projects PacifiCorp has undertaken. PacifiCorp is required to submit a smart grid report to four (Oregon, Utah, Washington, and Wyoming) of the six state commissions in PacifiCorp's service territory.

D. Energy Storage

For its 2013 IRP, PacifiCorp modeled storage as available supply-side resources. The types of storage resources include pumped storage, sodium-sulfur battery, compressed air energy storage, and fly wheel. The characteristics and costs of the resources were developed by HDR Engineering, Inc., an independent consulting firm. The HDR Engineering report is provided as Attachment B.

Each type of storage resource has a range of costs that depend on its respective development requirements, including factors such as topography, geology, environmental limitations, construction requirements, and level of maintenance needed for continued operation. Tables 6.1 and 6.3 in the 2013 IRP, Volume I, summarize the information for the different types of energy storage resources modeled in the 2013 IRP. The portfolios developed in the 2013 IRP process do not include energy storage resources because these resources were not selected among the least cost resources available.

Informal inquiries may be directed to Gary Tawwater, Manager, Regulatory Affairs, at (503) 813-6805.

Sincerely,

William R Griffith/B

William R. Griffith
Vice President, Regulation

Enclosure

Attachment A

Date: October 4, 2012

To: PacifiCorp

From: The Cadmus Group

Re: Revised Overview of CHP Inputs, Data Sources, and Potential Study Results

Introduction

Cadmus is calculating the levelized cost and producing supply curves for combined heat and power (CHP) systems projected to be installed in PacifiCorp territory over the next 20 years as part of the 2012 update to the Integrated Resource Plan (IRP). This memo has three purposes: 1) explain the sources that we referenced for this analysis, 2) present data we used in the analysis, and 3) provide the results.

Cadmus presented draft results to stakeholders on August 24. Stakeholder input was considered in refining the analysis. The final results are presented in this memo, with responses to stakeholder comments included at the end.

The levelized cost is calculated based on the Total Resource Cost (TRC) perspective for all states. The IRP treats CHP systems as Qualifying Facilities, defined by The Public Utility Regulatory Policies Act of 1978 (PURPA), so the TRC is used in all jurisdictions for consistency with treatment of other generation resources in the IRP. The levelized cost, which compares the life-cycle costs to the energy savings, is based on a single system and is calculated separately for each state, installation year, system configuration (generation technology and size range) and fuel type.

The TRC levelized cost includes:

- The installation cost, less the federal investment tax credit (ITC) for systems installed before 2017. The installation cost is based on a national cost and adjusted for the cost of living in each state (using adjustment factors for cities in PacifiCorp's service territory in each state).
- The ITC is 30% of the installed cost for fuel cells and 10% for other technologies. The incentive is unaffected by utility or state rebates received. The ITC expires December 31, 2016, which is taken into account in the analysis.
- The interconnection cost, based on system size and PacifiCorp data from past installations.
- The operation and maintenance (O&M) costs that are assumed to occur annually and are adjusted to net present value.

- Fuel costs, using PacifiCorp projections for average annual natural gas costs, by service territory (Pacific Power and Rocky Mountain Power).[1]

Additionally, PacifiCorp's nominal discount rate of 6.88% is used along with an inflation rate of 1.9% to adjust the costs in future years. The costs are then divided by the energy production of the system over its life to obtain the levelized cost of conserved energy. The energy production includes a line loss factor, varying by state and sector, as provided by PacifiCorp. The energy production over the life of the system takes into account system performance degradation.

Technologies Assessed

CHP systems generate electricity and utilize waste heat for a thermal load such as space or water heating. They can be used in buildings that have a fairly coincident thermal and electric load, or buildings where combustible biomass or biogas is produced. CHP has traditionally been installed primarily in hospitals, schools, and manufacturing facilities, but can be used across nearly all segments with an average monthly energy load greater than about 30 kW. CHP is broadly divided into subcategories based on the fuel used. Nonrenewable CHP typically runs on natural gas, while renewable CHP runs on a biologically derived fuel (biomass or biogas).

The nonrenewable CHP systems analyzed are reciprocating engines (RE), microturbines (MT), gas turbines (GT), and fuel cells (FC). Reciprocating engines cover a wide size range, while gas turbines are typically large systems. Fuel cells and microturbines are newer technologies with higher capital costs, and fuel cells have the highest electrical conversion efficiency.

The renewable CHP assessment analyzed industrial biomass systems and anaerobic digester biogas systems.

- Industrial biomass systems, utilized in industries such as lumber mills or pulp and paper manufacturing, where site-generated waste products are combusted in place of natural gas or other fuels. Industrial biomass systems are generally large scale, using generators such as steam turbines (ST) with a capacity greater than 1 MW.
- Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste. Anaerobic digesters can be coupled with a variety of generators, including REs and MTs, and are typically installed at landfills, wastewater treatment facilities (WWTF), and livestock farms.

[1] PacifiCorp provided annual gas rate projections (nominal $/MMBtu) for use in the levelized cost analysis. Note that these prices change in each IRP scenario.

Data Sources

Cadmus reviewed many sources of data to determine the most appropriate inputs for the CHP analysis. As shown in Table 1, EPA and DOE reports on CHP technologies were used for many inputs, with other sources used for additional inputs, as appropriate.

Table 1. References for CHP Analysis

Source	Inputs	Website Link
Catalog of CHP Technologies, U.S. EPA	System Size, Installed Cost, Heat Rate, O&M Cost	www.epa.gov/chp/documents/catalog_chptech_full.pdf
Biomass Combined Heat and Power Catalog of Technologies, U.S. EPA	System Size, Heat Rate, O&M Cost, WWTF Data	www.epa.gov/chp/documents/biomass_chp_catalog.pdf
R.S. Means	State Cost Adjustment	N/A
Combined Heat and Power Partnership, U.S. EPA	Federal Investment Tax Credit	www.epa.gov/chp/incentives/
Gas-Fired Distributed Energy Resource Technology Characterizations, U.S. DOE	Measure Life	www.nrel.gov/docs/fy04osti/34783.pdf
California Self-Generation Incentive Program 10th Impact Evaluation Report	Capacity Factor	www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
California Self-Generation Incentive Program Combined Heat and Power Performance Investigation	Performance Degradation	www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities, U.S. EPA	Agricultural CHP Data	www.epa.gov/agstar/documents/biogas_recovery_systems_screenres.pdf
Agricultural Waste Management Field Handbook, USDA	Agricultural CHP Data	policy.nrcs.usda.gov/OpenNonWebContent.aspx?content=31475.wba
Census of Agriculture, USDA	Farm Data	www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_State_Level/
Landfill Methane Outreach Program (LMOP), U.S. EPA	Landfill Gas Data	www.epa.gov/lmop/
Energy Insights	CHP Eligibility by Facility Type and Size	N/A
Combined Heat and Power Installation Database	Existing CHP Installations	www.eea-inc.com/chpdata/
PacifiCorp	2011 Customer Data, Interconnection Cost, Gas Costs, Inflation Rate, Discount Rate, Line Losses	N/A

Inputs

Summaries of the key inputs for each technology are provided in the tables below. Table 2 through Table 5 list the assumptions for nonrenewable fuel systems by technology and size range. Table 6 and 7 list the assumptions for renewable fuel systems by fuel and technology.

The net heat rate, measured in Btu/kWh, is defined as the increased system fuel use (total fuel input to the CHP system minus the fuel that would be normally used to generate the same thermal output) divided by the electricity output. In biogas systems, the analysis assumes that waste heat is fed back to the anaerobic digester for generation of the biogas, so the total heat rate is used, rather than net heat rate.

For biogas systems, the cost represents the cost of the generator. Additional expense to build the digester is not included as that could be completed independently of the CHP system. Similarly, for biomass systems, we assumed the boiler and fuel processing systems are already in place at these large industrial facilities, and so only the cost for the CHP generator is included.

Table 2. Inputs for Natural Gas Fuel Cells

Input	100-250 kW	250-750 kW	750-1,500 kW
National average installation cost ($/kW)	$6,310	$5,580	$5,250
Annual O&M cost ($/kWh)	$0.038	$0.035	$0.032
Net heat rate (Btu/kWh)	4,168	6,022	6,043
Annual performance degradation	5%		
Capacity factor	0.71		
Measure life (years)	10		
Federal Investment Tax Credit through 2016	30% of installed cost		

Table 3. Inputs for Natural Gas-Fired Gas Turbines

Input	<3,000 kW	≥3,000 kW
National average installation cost ($/kW)	$3,324	$1,314
Annual O&M cost ($/kWh)	$0.0111	$0.0074
Net heat rate (Btu/kWh)	7,013	5,839
Annual performance degradation	0%	
Capacity factor	0.81	
Measure life (years)	20	
Federal Investment Tax Credit through 2016	10% of installed cost	

Table 4. Inputs for Natural Gas-Fired Microturbines

Input	<50 kW	50-150 kW	>150 kW
National average installation cost ($/kW)	$2,970	$2,490	$2,440
Annual O&M cost ($/kWh)	$0.020	$0.0175	$0.016
Net heat rate (Btu/kWh)	7,313	5,796	6,882
Annual performance degradation	5%		
Capacity factor	0.49		
Measure life (years)	10		
Federal Investment Tax Credit through 2016	10% of installed cost		

Table 5. Inputs for Natural Gas-Fired Reciprocating Engines

Input	<200 kW	200-500 kW	500-2,000 kW	2,000-4,000 kW	>4,000 kW
National average installation cost ($/kW)	$2,210	$1,940	$1,640	$1,130	$1,130
Annual O&M cost ($/kWh)	$0.022	$0.016	$0.013	$0.010	$0.009
Net heat rate (Btu/kWh)	4,383	4,470	4,385	5,107	4,950
Annual performance degradation	6%				
Capacity factor	0.40				
Measure life (years)	20				
Federal Investment Tax Credit through 2016	10% of installed cost				

Table 6. Inputs for Industrial Biomass Steam Turbine Systems

Input	<2,000 kW	2,000-5,000 kW	>5,000 kW
National average installation cost ($/kW)	$1,117	$475	$429
Annual O&M Cost ($/kWh)	$0.004		
Heat rate (Btu/kWh)	4,515	4,568	4,388
Annual performance degradation	1%		
Capacity factor	0.90		
Measure life (years)	25		
Federal Investment Tax Credit through 2016	10% of installed cost		

Table 7. Inputs for Biogas Systems

Input	FC	GT	MT	RE
National average installation cost ($/W)	$5,713	$2,319	$2,633	$1,610
Annual O&M Cost ($/kWh)	$0.025	$0.0085	$0.014	$0.0165
Heat rate (Btu/kWh)	8,705	12,400	12,703	10,357
Annual performance degradation	5%	0%	5%	6%
Capacity factor	0.71	0.81	0.49	0.40
Measure life (years)	10	20	10	20
Federal Investment Tax Credit through 2016 (% of installed cost)	30%	10%	10%	10%

The installation costs in the above tables are based on national averages. In the analysis, these values are adjusted for each state based on the cost of living in the part of that state served by PacifiCorp. These adjustment factors (the cost in each state as a percentage of the national average cost) are shown in Table 8.

Table 8. Cost Adjustments by State

	CA	ID	OR	UT	WA	WY
Material	103%	100%	100%	81%	103%	99%
Labor	114%	65%	97%	69%	93%	49%
Total	107%	88%	99%	77%	99%	82%

Levelized Cost of Energy

Cadmus calculated the levelized cost of energy for each configuration described above in each state and installation year (2013-2032). Table 9 shows the results for units installed in 2013. Levelized cost values for all other installation years are provided in the accompanying workbook (PAC 2013IRP_CHP LCOE_10-03-12.xlsx). There is a slight increase in costs for systems installed after 2016, when the federal tax credit expires. Levelized costs vary across states due to differences in cost-of-living adjustments, line losses, and gas rates.

Table 9. 2013 Levelized Cost by Configuration and State

Technology	Size Range	CA	ID	OR	UT	WA	WY
Fuel Cell	100-250 kW	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15
	250-750 kW	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14
	750-1,500 kW	$0.13	$0.13	$0.14	$0.14	$0.14	$0.14
Gas Turbine	<3,000 kW	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
	>3,000 kW	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Microturbine	<50 kW	$0.13	$0.13	$0.14	$0.14	$0.14	$0.13
	50-150 kW	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
	>150 kW	$0.11	$0.11	$0.11	$0.11	$0.12	$0.11
Reciprocating Engine	<200 kW	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10
	200-500 kW	$0.08	$0.08	$0.09	$0.09	$0.09	$0.09
	500-2,000 kW	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
	2,000-4,000 kW	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
	>4,000 kW	$0.06	$0.07	$0.07	$0.07	$0.06	$0.06
Biomass - Steam Turbine	<2,000 kW	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	2,000-5,000 kW	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	>5,000 kW	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Biogas	Fuel Cell	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
	Gas Turbine	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
	Microturbine	$0.05	$0.06	$0.06	$0.06	$0.05	$0.06
	Reciprocating Engine	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04

Technical Potential

The technical CHP potential was calculated based on sources described above, including PacifiCorp customer data, and data on farms, landfills and WWTFs in the PacifiCorp service territory. The total calculated technical potential is 4,301 MW. Table 10 details technical potential in rated system capacity (MW).

The average energy production is based on the capacity factors of the systems described above. To avoid double-counting opportunities across technologies, the total potential for each size range was divided into different technologies based on the distribution of existing installations for states within PacifiCorp territory. For example, for systems less than 500 kW, reciprocating engines, microturbines, and fuel cells represent 77%, 19%, and 4% of installations, respectively. For all technologies, across all states, the technical potential for energy generation is estimated to be 2,233 aMW (an average capacity factor of 0.52).

Table 10. Technical Potential

System Type	Technical Potential (MW)						
	CA	ID	OR	UT	WA	WY	Total
Natural Gas	54	162	346	2,546	449	354	3,911
< 500 kW	*31*	*82*	*156*	*1,053*	*212*	*158*	*1,693*
500-999 kW	*3*	*8*	*40*	*409*	*87*	*36*	*583*
1-4.9 MW	*20*	*45*	*108*	*818*	*151*	*110*	*1,252*
5 MW+	*0*	*26*	*42*	*264*	*0*	*49*	*382*
Biomass	12	3	141	41	31	6	233
< 500 kW	*1*	*2*	*22*	*11*	*5*	*1*	*43*
500-999 kW	*1*	*1*	*15*	*6*	*4*	*2*	*29*
1-4.9 MW	*10*	*0*	*71*	*16*	*13*	*3*	*113*
5 MW+	*0*	*0*	*32*	*8*	*8*	*0*	*48*
Biogas	2	22	31	52	8	42	157
Landfill	*0*	*0*	*1*	*8*	*5*	*3*	*17*
Farm	*2*	*22*	*29*	*44*	*3*	*39*	*139*
WWTF	*0*	*0*	*1*	*0*	*0*	*0*	*1*
Total	68	187	519	2,639	488	402	4,301

Market Potential

Cadmus applied data on recent CHP system installations in the PacifiCorp service area to determine the market potential, or likely installations in future years. The rate of assumed annual market penetration is based on actual capacity installed relative to estimated technical potential, calculated by dividing the average annual capacity (MW) of CHP installed from 2008 through 2011 by the estimated technical potential for the period 2008-2032.[2] That percentage of technical potential installed each year was applied to the 20-year technical potential estimated in this study to calculate market potential over the next 20 years, as shown in Table 11 and Table 12.

In this study, the 2032 market potential estimate is 250 MW, compared to 260 MW in Cadmus' 2011 study.[3]

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[2] Technical potential for 2008-2032 was calculated by adding the actual installations from 2008-2011 to the 20-year technical potential estimated in this study. Because installation data is not yet available for 2012, we assumed the rate of installation in 2012 to equal the average of 2008-2011. The rate of market penetration was calculated as one value across the PacifiCorp service area, due to the limited number of installations.

[3] Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, Volume I, Cadmus Group, March 2011, page 84, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_VolumeI_2011_Study.pdf

Table 11. 2032 Market Potential (Based on Current Market Conditions) by State

Technology	Projected Installations in 2032						
	CA	ID	OR	UT	WA	WY	Total
System Capacity (MW)	4	11	31	153	28	23	*250*
Number of Systems	13	33	73	358	71	63	*612*
Total Energy (aMW)	2	5	18	74	13	11	*125*

Table 12. 2032 Market Potential (Based on Current Market Conditions) by Fuel

Technology	Projected Installations in 2032			
	Natural Gas	Industrial Biomass	Biogas	Total
System Capacity (MW)	227	15	8	*250*
Number of Systems	569	17	26	*612*
Total Energy (aMW)	108	13	4	*125*

Responses to Stakeholder Comments

1. The heat rate units and explanation in the memo seem incorrect and would benefit from a re-evaluation. The LCOE workbook shows different estimates for net heat rate in units of kBtu/kWh. The values are similar, but not identical to the values shown in the memo. The net heat rate is not defined but it is used to reflect the net fuel cost impact so it is the equivalent of heat rate chargeable to power. The units in the memo should read "BTU/kWh"

CADMUS: We have updated the LCOE analysis using net heat rate values (in Btu/kWh) from the *Catalog of CHP Technologies*, prepared for EPA in December 2008. The memo has been updated with the new values and reference.

2. California Self-Generation Incentive Program (SGIP) should not be used for this analysis.

- The cost averages reflect the growing pains of the distributed generation industry in an early market development period and do not represent best practices today and moving forward over the next twenty years.

  CADMUS: The equipment cost values are now based on the *Catalog of CHP Technologies* report, rather than California SGIP data. The national averages in that report are adjusted for each state in the PacifiCorp territory based on cost of living adjustment factors from RS Means. Interconnection costs were added using a formula for interconnection costs based on equipment size that we developed using data from PacifiCorp of actual costs.

- The California SGIP has historically focused on small CHP systems, primarily systems less than one megawatt with reduced incentives for systems up to five megawatts. Larger systems have lower capital costs, lower O&M costs, higher thermal utilization, and higher load factors than the smaller systems that were the focus of the SGIP program. As a result the most economic portion of the CHP market is left out of the Cadmus economic comparison.

  CADMUS: SGIP system sizes are no longer used in the analysis. The LCOE analysis has been modified to examine two to five size ranges for each technology, rather than one average for each technology. Different equipment costs ($/kW) are used for each of these size ranges, based on data from the *Catalog of CHP Technologies* report.

- Larger CHP systems, particularly gas turbines and reciprocating engines, show economies of scale and have lower unit costs. This is particularly true for gas turbines which can often be one to two orders of magnitude larger for CHP systems than the 3,200 kW used in the Cadmus report. It should also be noted that the low end 3,200 kW gas turbine system modeled in the Cadmus analysis has relatively high capital cost and lower efficiency than gas turbine systems even slightly larger in size.

  CADMUS: As described above, the updated analysis includes a range of system sizes for each technology.

- The program stopped providing incentives for natural gas fired reciprocating engines, microturbines, and gas turbines in 2007. Therefore, the population of estimates for these technologies is largely out of date.

CADMUS: SGIP data is no longer used for most parameters in this analysis.

- The original purpose of the California SGIP program was to promote new generation capacity at a time when California was facing capacity shortages. Because of this, many of the initial CHP systems installed under the program appear to have been oversized in relation to site thermal loads and CHP system thermal utilization suffered.

  CADMUS: The updated analysis is based on data from *Catalog of CHP Technologies*, rather than using this SGIP data.

- Heat rate values are all quite high because they are based on the historical observation of low thermal utilization rates in the early California SGIP CHP systems. The values do not represent the capabilities of a well-designed and maintained CHP system today. These high heat rate estimates significantly overstate the LCOE calculations in the Cadmus report.

  CADMUS: The updated analysis uses heat rates from *Catalog of CHP Technologies*, rather than SGIP.

- The observed historical California SGIP installations significantly undervalue the expected capacity factor for CHP in high load factor applications. Each of the CHP systems is capable of having an availability factor of 95%. An economically-designed installation must be based, as much as possible, on continuous system operation.

  CADMUS: While a 95% capacity factor is theoretically possible, Cadmus believes it is more accurate to base our projections on actual capacity factors and degradation rates of operating systems. We understand the limitations in applying SGIP data for PacifiCorp so we have replaced it with other sources where possible, but we have not found better sources for capacity factor. The performance degradation rates are still based on SGIP data, but were updated based on a report (*Self-Generation Incentive Program Combined Heat and Power Performance Investigation*) that breaks down the SGIP degradation into more detail, allowing us to modify our analysis to apply only the portion of degradation based on reduction of system efficiency. If other references can be provided, Cadmus will review them and consider if they can be used to refine our analysis.

3. The assumed price of natural gas is too high. Values are higher than those in the latest EIA Annual Energy Outlook.

CADMUS: The updated analysis uses natural gas prices from PacifiCorp’s latest forward price curve. These values are used to calculate a base case levelized cost to include in the potential study report.

Note that this base case levelized cost is not used for IRP modeling. Rather, the IRP models will apply low, medium, and high natural gas price forecasts as the fuel cost for CHP resources in line with their treatment as thermal units.

4. Why is CHP treated on a TRC basis in Utah?

CADMUS: These sites are considered PURPA Qualifying Facilities rather than Demand-Side Management opportunities and are thus treated like other supply-side resources. As such, the administrative adder has been removed from Cadmus' analysis and replaced with PacifiCorp's interconnection cost.

5. Where the value of heat generated by the CHP system taken into account?

CADMUS: For non-renewable options, the analysis assumes that waste heat offsets fossil fuel consumption for space and/or water heating and thus does not save electricity. Net heat rates are used so the fuel use included in LCOE calculations is only the increased fuel use for electricity generation.

The analysis assumes that biomass systems are installed at facilities that already have wood/paper waste and are using that waste in a boiler. The addition of a generator would add the benefit of electricity generation through CHP. Since the heat is already being generated, the analysis doesn't include a waste heat benefit and also doesn't include capital costs other than the generator.

In biogas systems, the analysis assumes that waste heat is fed back to the anaerobic digester for generation of the biogas.

6. Are the CHP plants assumed to dispatch against market electricity prices or will they operate in response to the host facility heat/electricity needs?

CADMUS: CHP plants are assumed to dispatch against market prices.

7. O&M Costs – The O&M estimates used in the Cadmus report are from a source that is out of date. The costs from the CEC's online Distributed Energy Resources Guide are shown in the table below. With the exception of the very low estimate for fuel cell O&M, the difference in cost estimates do not make a large difference in the LCOE calculation.

O&M Costs, $/kWh	Size, kW	Cadmus - First Draft	CEC	Cadmus - Updated (from EPA reports)
Reciprocating Engine	620	$0.013	$0.016	$0.009 - $0.022
Microturbine	170	$0.012	$0.022	$0.016 - $0.02
Fuel Cell	520	$0.005	$0.035	$0.032 - $0.038
Gas Turbine	3,200	$0.013	$0.010	$0.0074 - $0.0111

CADMUS: The updated analysis uses O&M cost data, added to the table above, from the Catalog of CHP Technologies report and its companions report suggested below, the Biomass CHP Catalog of Technologies. We don't see a date on the CEC DER Guide so we cannot confirm which is the most current source.

8. The biomass LCOE of 2 cents/kWh is quite low.

- The estimate is based on capital costs of $1,800/kW. This estimate should likely be at least doubled. A recent study reviewed by ICF, details confidential, showed capital costs for a 20 MW biomass power plant at $4,800/kW and a 55 MW plant at $3,200/kW.

  CADMUS: The updated analysis uses capital cost data from *Catalog of CHP Technologies*. If another reference can be provided (with sufficient detail for every technology considered), Cadmus will review its appropriateness to determine if it is more suitable for this analysis.

- In the Cadmus report, the biomass feedstock is assumed to be used at no cost. Solid biomass fuels need to be collected and prepared, and the costs for this need to be taken into consideration in the analysis. It is unrealistic to assume that there are no costs associated with this part of the system.

  CADMUS: In this analysis, it is assumed that the biomass is a waste product generated on site and applicable facilities already include feedstock processing, so any additional collection and processing cost to use a generator is minimal.

- O&M costs assumed in the Cadmus report are very low. A solid fueled system requires more operating and maintenance labor expenses as well as more fuel processing and handling expenses than does a natural gas fired system. (For more detailed information, see "Biomass CHP Catalog of Technologies" from the EPA CHP Partnership at http://www.epa.gov/chp/basic/catalog.html#biomasscat)

  CADMUS: The referenced report was used in the updated analysis.

9. The analysis underestimates the CHP potential by excluding bottoming-cycle CHP, also known as waste heat to power (WHP). These systems convert excess, otherwise-wasted thermal energy or pressure from industrial processes or pipeline compressor stations into electricity. Although the Cadmus report analysis notes the difficulty in finding information to quantify the potential, it is reasonable to consider that the value is greater than zero.

CADMUS: We have researched WHP systems and identified several challenges:

- There is currently very little WHP installed in US (33 sites, 557 MW, excluding landfill gas)
- Only applicable in industries with high temperature heat produced (e.g. metal and chemical manufacturing)
- The technical barriers are relatively significant (e.g. space limitations, disperse waste

heat sources, low volume/seasonal operations)

Although there are potential energy savings from WHP, the low market awareness and willingness to adopt at this time, coupled with relatively significant technical barriers, indicate the market potential for these applications is small.

Attachment B

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

Prepared for:
PacifiCorp Energy
Salt Lake City, Utah

Prepared by:
HDR Engineering, Inc.

December 2011

Table of Contents

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1 EXECUTIVE SUMMARY

HDR Engineering (HDR) has been retained by PacifiCorp Energy (PacifiCorp) to perform an Energy Storage Study to support PacifiCorp's 2012 Integrated Resource Plan (IRP) intended to evaluate a portfolio of generating resources and energy storage options. The scope of this Energy Storage Study is to develop a current catalog of commercially available and emerging large, utility-scale and distributed scale energy storage technologies as well as define respective applications, performance characteristics, and estimated capital and operating costs for each technology.

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

- Pumped Storage Hydroelectric
- Battery Energy Storage Systems
- Compressed air energy storage (CAES)
- Flywheels

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.

Pumped storage hydroelectric and Compressed Air facilities are classified as mass energy storage projects capable of providing thousands of Megawatt hours (MWh) of dispatchable energy based on potential energy, in the form of water, stored in an upper reservoir. Pumped storage is ideal for applications such as load shifting, peak shaving, spinning reserve, and frequency regulation on a large scale (200 to 1,000+ MW). Interconnection of these facilities requires availability of EHV transmission lines. Pumped storage facilities require site-specific attributes and resources. Two reservoirs, or locations suitable for new reservoirs, in close proximity with an elevation difference between them are required. Additionally, the development, design, and construction of these facilities require significant capital investment and time.

Table 1- Summary of Highlighted Pumped Storage Projects

Item	Swan Lake North	Yale-Merwin	JD Pool	Parker Knoll
Location	OR	WA	WA	UT
Approx. static head (ft)	1,300	270	1,880	2,500
Energy storage (MWh)	11,000	2,550	11,300	10,000
Assumed hours of storage (hrs)	10	10	10	10
Resulting installed capacity (MW)	1,100	255	1,130	1,000
Estimated Capitol Cost	\$1.7-\$3.3 billion	\$0.38-\$0.77 billion	\$1.7-\$3.4 billion	\$1.5-\$3.0 billion
Estimated O&M Costs	\$8,500,000	\$3,300,000	\$8,600,000	\$8,000,000

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 FERC licensing process. Four projects have been selected for this report: Yale-Merwin Pumped Storage Project, JD Pool Pumped Storage Project, Parker Knoll Pumped Storage Project, and Swan Lake North Pumped Storage Project. These proposed sites were selected due to existing project features within the PacifiCorp balancing area footprint, environmental impacts that are fairly well understood, and the current project development status. Please see the summary table below for a summary of their project parameters.

Battery energy storage systems are considered to be a small scale energy storage option focused on applications such as power quality and back up power for independent generating or operating facilities. When connected to smaller electrical grids, e.g., islanded systems, batteries can be implemented to provide services such as spinning reserve and frequency regulation. In the case of renewable integration, batteries primarily function to provide ramp rate control or applications focused on complementing the generation profile of the resource in order to lessen the burden of required ancillary services. The battery technologies, and their respective manufacturers, reviewed for this study include:

- Sodium sulfur (NAS) – NGK Insulators, Ltd
- Lithium ion (Li-ion) – A123 Systems
- Vanadium Redox (VRB) – Prudent Energy
- Zinc Bromide (ZnBr) – Premium Power
- Dry Cell – Xtreme Power, Inc.

A Compressed Air Energy Storage Plant (CAES) 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 a couple of plants are currently in operation, including Alabama Electric Cooperative's (AEC) McIntosh plant which began operation in 1991.

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. Generally, flywheels are used for short durations in the application of a supplying backup power in a power outage event, regulating voltage and frequency.

HDR has performed an initial comparison of the energy storage technologies discussed in this document. Table 2 below lists some of the key criteria that were compared when considering these technologies. A more detailed comparison is included in Appendix A. Comments on the overall commercial development of the technology, the applications that each technology is suited to, space requirements for each technology, performance characteristics, project timelines, and capital, operating and maintenance costs have been made to aid PacifiCorp in its IRP considerations.

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. CAES and pumped storage are considered to be the only functional technologies suitable for bulk energy storage as stand-alone applications. 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. Space requirements for energy storage systems vary depending upon capacity and power, and pumped storage and CAES are capable of much higher capacities and total energy storage and therefore their project footprint is substantially higher. Project timelines vary widely for the various options. Pumped storage requires 5 years for FERC licensing and 5 years for construction, timelines for CAES are on the order of 2 years, and batteries and flywheels development times are on the order of 1 year.

There are a number of challenges associated with comparing cost of the different types of energy storage technologies. 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.

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.

Table 2- Energy Storage Technology Summary Table

	Pumped Storage Hydro	Compressed Air Energy Storage	Batteries	Flywheels
Range of power capacity (MW) for a specific site (For pumped storage, four sites were considered within the PacifiCorp footprint)	255-1,130	100+	1-32	1-20
Range of energy capacity (MWh) (For Pumped Storage, four sites were considered within the PacifiCorp footprint)	2,550-11,300	800+	Variable depending on DOD	0.25-5
Range of capital cost ($ per kW)	$1,500-$3,000	$1,400-$1,700	$450-$4,000	$2,400/kW or $600 per kW plus $1,600 per kWh.
Year of first installation	1929	1978	1995 (sodium sulfur)	2007

A variety of complementing technologies will be required to fully address the effects of variable renewable energy, including bulk storage, distributed storage, and improvements to the interconnecting transmission system, and can extend the argument to bulk storage itself.

2 INTRODUCTION

PacifiCorp, as well as various regions of the United States, faces a major challenge in balancing increasing levels of variable energy resources (VER). 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 2012 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, and 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 will be required. For that reason, PacifiCorp has engaged HDR Engineering, Inc (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 projects. Energy storage for utility-scale applications has historically utilized pumped-storage hydro 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, compressed air energy storage, and flywheels. 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 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

It should first be pointed out that variability is not a new phenomenon in power system operation. Demand has fluctuated up and down since the first consumer was connected to the first power plant. The resulting 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 VER 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 already required. At small penetrations — a few percent in most systems — the additional effort is likely to be slight, because VER fluctuations will be dwarfed by those already seen on the demand side.

Large shares, in contrast, will exaggerate existing 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 – in direct contrast to demand, highlighting the greater variability caused by a 30%+ penetration of variable supply to the peak demand.[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 VER output can ramp up and down extensively over just a few hours, but also because it may do so in a way that clashes with fluctuations in demand. In contrast, VER output may complement demand — when both increase or decrease at the same time.

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

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

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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

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, 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 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.

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 (CAES)
- Flywheels

Each of these technologies has been employed for grid scale storage or to provide ancillary services. Many of these technologies, such as flywheels, have been proven 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, but presently system planners are left with uncertainty as to which technologies will be viable for bulk energy-storage applications, particularly for the immediate and future need for variable energy resource integration.

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).

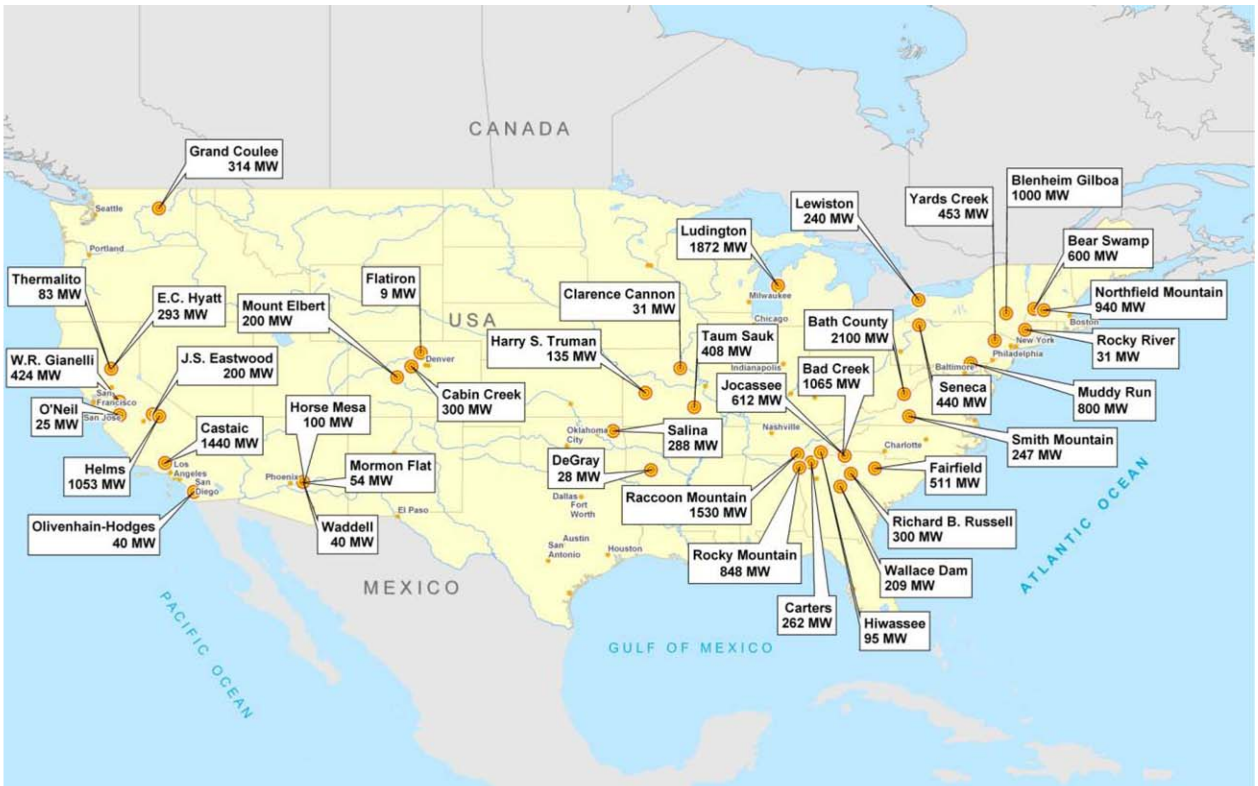

Figure 1- Existing Pumped Storage Projects in the United States

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.

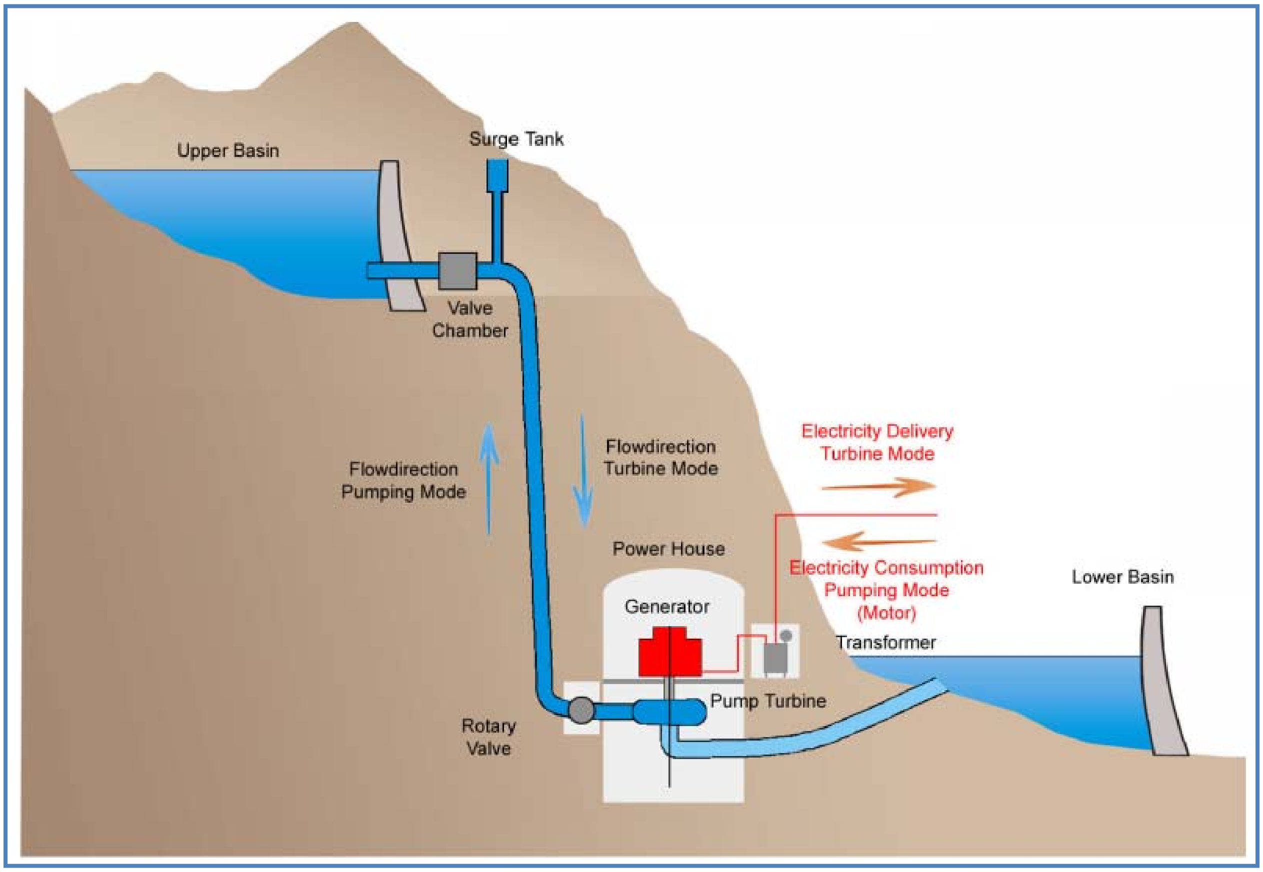

Figure 2-Typical Pumped Storage Plant/System

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 *Mature Technologies*

3.1.1.1 Fixed Speed Pump-turbines

Pumped storage is the most mature energy storage technology in today's market. The first U.S. pumped-storage plant was developed in the 1920s to balance loads from fossil fuel plants. The generating equipment for the majority of the existing pumped storage plants in the U.S. is the reversible, single-stage Francis pump-turbine. See Figure 3 below for a cross section of this type of equipment. The runner-impeller changes the direction of its rotation to operate in either the pumping or generating mode. The generator-motor changes direction with the runner-impeller to either provide power in the pumping direction or generate electrical power when the unit is in the turbine mode. Most of the major equipment vendors have significant experience with this type of unit, and can apply modern designs for runners, wicket gates, and water passageway shape modifications to older machines during rehabilitation programs, resulting in significant efficiency and capacity improvements. The technology for single-stage units continues to advance, and a broader range of equipment configurations are available depending upon the available head, reservoir volume, and desired operation.

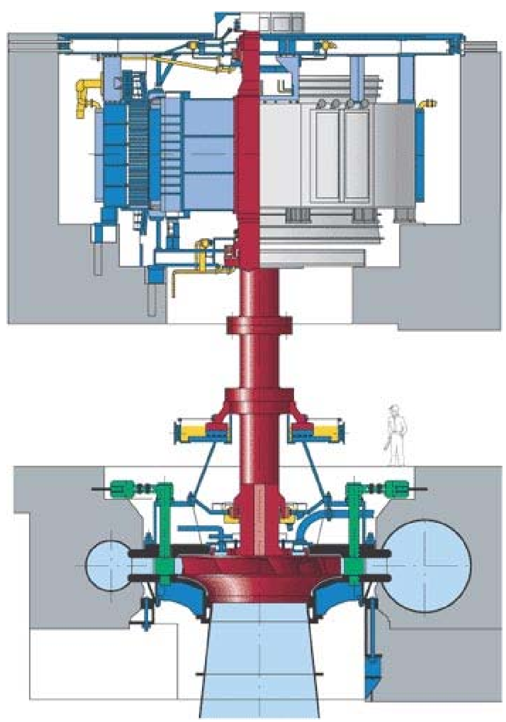

Figure 3- Reversible Francis Type Pump-turbine (Voith)

3.1.1.2 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. The Yale-Merwin project, one of the highlighted projects within the PacifiCorp area, is not technically a closed-loop system, but because the project would be constructed as part of an existing conventional hydropower project with two existing man made reservoirs, its environmental impacts would be less significant and more predictable than for a true open-loop project.

3.1.2 *Emerging Technologies*

3.1.2.1 Variable Speed Pump-turbines

With the introduction of Renewable Portfolio Standards in many states, there has been renewed interest in new pumped storage projects in the United States. Until recently, the U.S. electric grid system requirements did not dictate the need for potentially significant quantities of energy storage, and the subsequent increased incremental expense of new advanced pump-turbine designs, including variable speed technology. The markets that could value the new technological advancements have yet to be developed in the U.S.; therefore, none of the existing pumped storage projects in the U.S. utilize variable speed. Also, the most recent pumped storage project constructed in the US was completed in the mid 1990s, and at that time, the technology was in its infancy. Variable speed technology has been significantly improved since that time and has been proven in Europe and Asia. For these reason and because variable speed technology is well suited to integration of variable renewable generation, many of the proposed new pumped storage projects are considering variable speed machines.

Variable speed pump-turbines have been used since the early to mid-1990's in Japan and late 1990s in Europe. They are being increasing considered during project development in Europe and Asia due to a high percentage of renewable integration in these areas and more developed commercial markets that compensate electricity producers for ancillary services. Although the technology has been in place since the 1990's, major equipment vendors are continuously redesigning the equipment to improve performance. In a conventional, single speed pump-turbine, the magnetic field of the stator and the magnetic field of the rotor always rotate with the same speed and the two are coupled. In a variable speed machine, those magnetic fields are decoupled. Either the stator field is be decoupled from the grid frequency using a frequency converter between the grid and the stator winding, or the rotor field is decoupled from the rotor body by a multi-phase rotor winding fed from a frequency converter which is connected to the rotor.

In California, three large pumped storage projects in development are considering variable speed technology almost exclusively due to the growing need for detrimental reserves at night, enabling greater penetration of variable renewable energy resources. A major hurdle these projects will face when making their final determination of the turbine technology will be the status of the economic markets, which will need to value to the benefits (revenue) of adjustable speed pump-turbines to justify the additional costs associated with the advanced equipment.

3.1.2.2 Underground Storage Reservoirs

Recently, the concept of locating one or both of the reservoirs for a pumped storage below ground has been considered. These sites have been evaluated due to the perceived lack of availability of potential surface reservoirs and the potential for reduced environmental impacts. Abandoned mines have been proposed for such a project, and the Elmhurst Quarry Pumped Storage Project (EQPS) in the City of Elmhurst, Illinois has been used for the basis of the project information in the summary matrix. It should be noted, however, that while many projects are under initial phases of development, there are no operating pumped storage projects worldwide that utilize underground reservoir. The underground excavation or materials costs, construction risk, and time required for underground excavation and construction make the economics of such a project questionable.

3.1.3 *Potential Projects in PacifiCorp Service Area*

HDR has made an assessment of fifteen potential projects located within the PacifiCorp balancing area. Projects were selected based on the preliminary filings with FERC and from the Yale Hydroelectric Plant – Plant Upgrade and Expansion Preliminary Engineering Report by Black and Veatch. Figure 4 below illustrates where proposed projects in the U.S. that have been granted and/or filed for a, FERC Preliminary Permit Application.

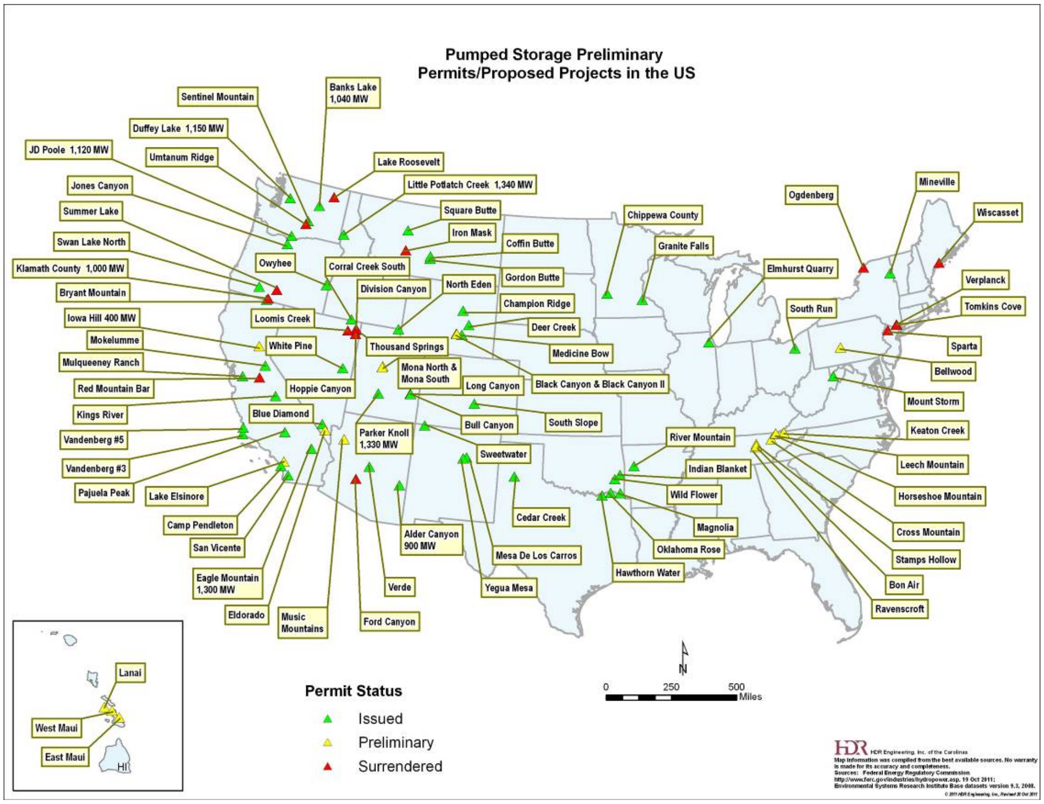

Figure 4- Preliminary Proposed Pumped Storage Projects

All projects in PacifiCorp's region were evaluated based on the selection criteria discussed in the following section.

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.

Table 3- Summary of Highlighted Pumped Storage Projects

Item	Swan Lake North	Yale-Merwin	JD Pool	Parker Knoll
Location	OR	WA	WA	UT
Approx. static head (ft)	1,300	270	1,880	2,500
Energy storage (MWh)	11,000	2,550	11,300	10,000
Assumed hours of storage (hrs)	10	10	10	10
Resulting installed capacity (MW)	1,100	255	1,130	1000
Estimated Capitol Cost	\$1.7-\$3.3 billion	\$0.38-\$0.77 billion	\$1.7-\$3.4 billion	\$1.5-\$3.0 billion
Estimated Annual O&M Costs	\$8,500,000	\$3,300,000	\$8,600,000	\$8,000,000

Fifteen projects have been evaluated based on the Criteria above and are presented in Appendix A. Four of these sites have been selected to highlight in this report:

- Yale- Merwin Pumped Storage Project
- JD Pool Pumped Storage Project
- Parker Knoll Pumped Storage Project

- Swan Lake North Pumped Storage Project

These proposed sites were selected due to existing project features, environmental impacts that are fairly well understood, and the current project development status. Table 3 above discusses a summary of these projects' characteristics.

3.1.3.2 Yale-Merwin Pumped Storage Project

The new Yale-Merwin Pumped Storage Project would be an expansion of the existing Yale Hydroelectric Project. The Yale Hydroelectric Project is a peaking plant located on the Lewis River approximately 22 miles east of Woodland, Washington. The existing project is a 135.7 megawatt (MW) powerhouse consisting of two vertical Francis units. PacifiCorp is interested in upgrading the existing plant and possibly constructing a new pumped storage plant. Pumped storage could increase the project capacity up to 255 MW. The project would consist of a new powerhouse with 3 new reversible Francis units, a new intake and water conduit that would connect to an existing diversion tunnel, and new penstocks. The project would utilize the tailrace for the existing project and only require improvements to the existing structure. See Figure 5 below for the site layout.

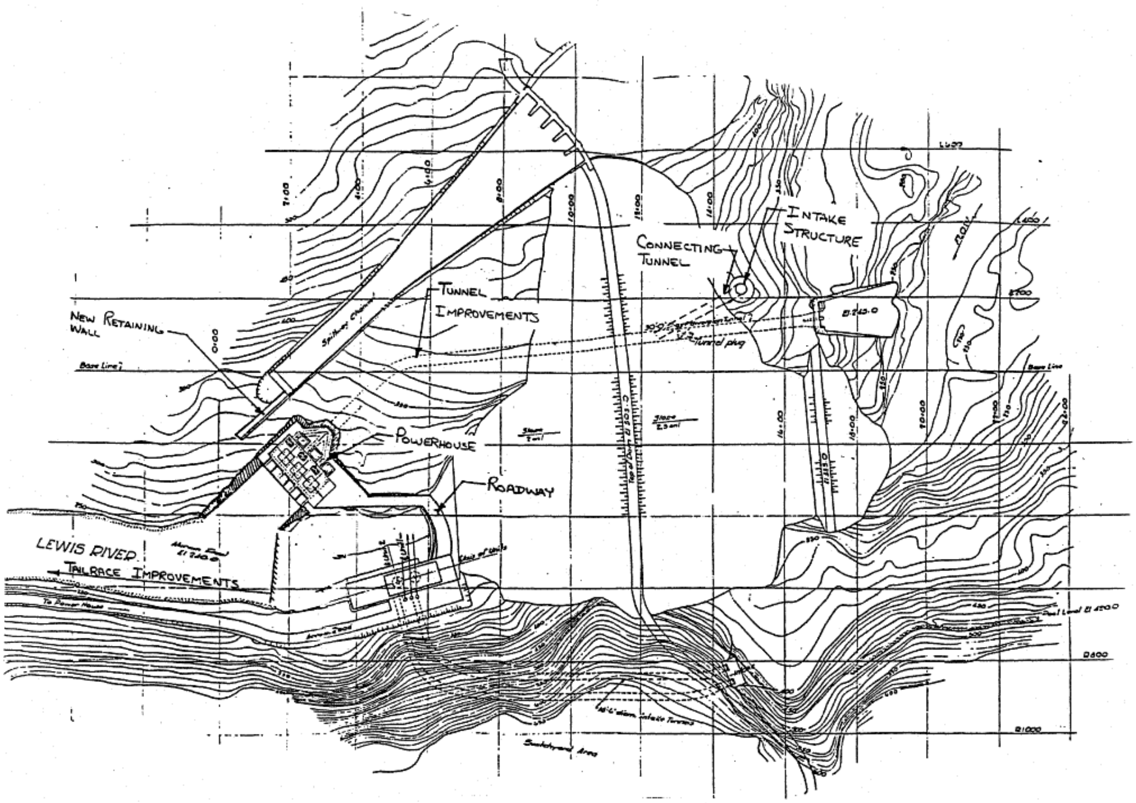

Figure 5- Yale Merwin Pumped Storage Site Layout (Black and Veatch)

Two options for the site are proposed with the minimum Merwin Lake elevation at either 220 feet (ft) or 235 ft. The licensing and environmental consideration for the Yale-Merwin Pumped Storage Project would be similar to project expansions or a relicensing effort associated with the existing Yale-Merwin Project. Potential issues could include fish impingement, entrainment, passage or barriers, upper and lower reservoir thermal effects, upper and lower reservoir water quality, and effects on existing generation. The Yale-Merwin Pumped Storage project is attractive due to two existing reservoirs, other existing infrastructure such as roads, transmission, and project features, and a good understanding of the potential licensing requirements.

3.1.3.3 JD Pool

The preliminary permit application for the JD Pool Pumped Storage Project (FERC No. 13333) in southern Washington (in the Columbia Gorge) was filed by the Klickitat Public Utility District and Symbiotics LLC on November 20, 2008. The permit was issued on May 5, 2009. The proposed project would consist of two new reservoirs, a new powerhouse, new water conduit, and transmission facilities. The project is estimated at 1,120 MW in capacity. The gross head at JD Pool would range between 1,815 and 1,930 ft.

The JD Pool project layout from the FERC Preliminary Permit is shown in Figure 6 below. The upper reservoir would have a surface area of approximately 190 acres with a storage capacity of 11,445 acre-feet (ac-ft) at a normal maximum surface elevation of 2,445 mean sea level (msl.) The earthen embankment would be 208 ft high and 4,330 ft long. The lower reservoir would have an approximate surface area of 160 acres with a storage capacity of 10,580 ac-ft at normal maximum surface elevation of 565 msl. The earthen embankment would be 65 ft high and 16,540 ft long. The reservoir would is proposed to be filled from off system sources. The reservoirs will be connected by a 24 ft diameter, 8,022 ft long steel penstock. A new ten unit powerhouse will be constructed as part of this project.

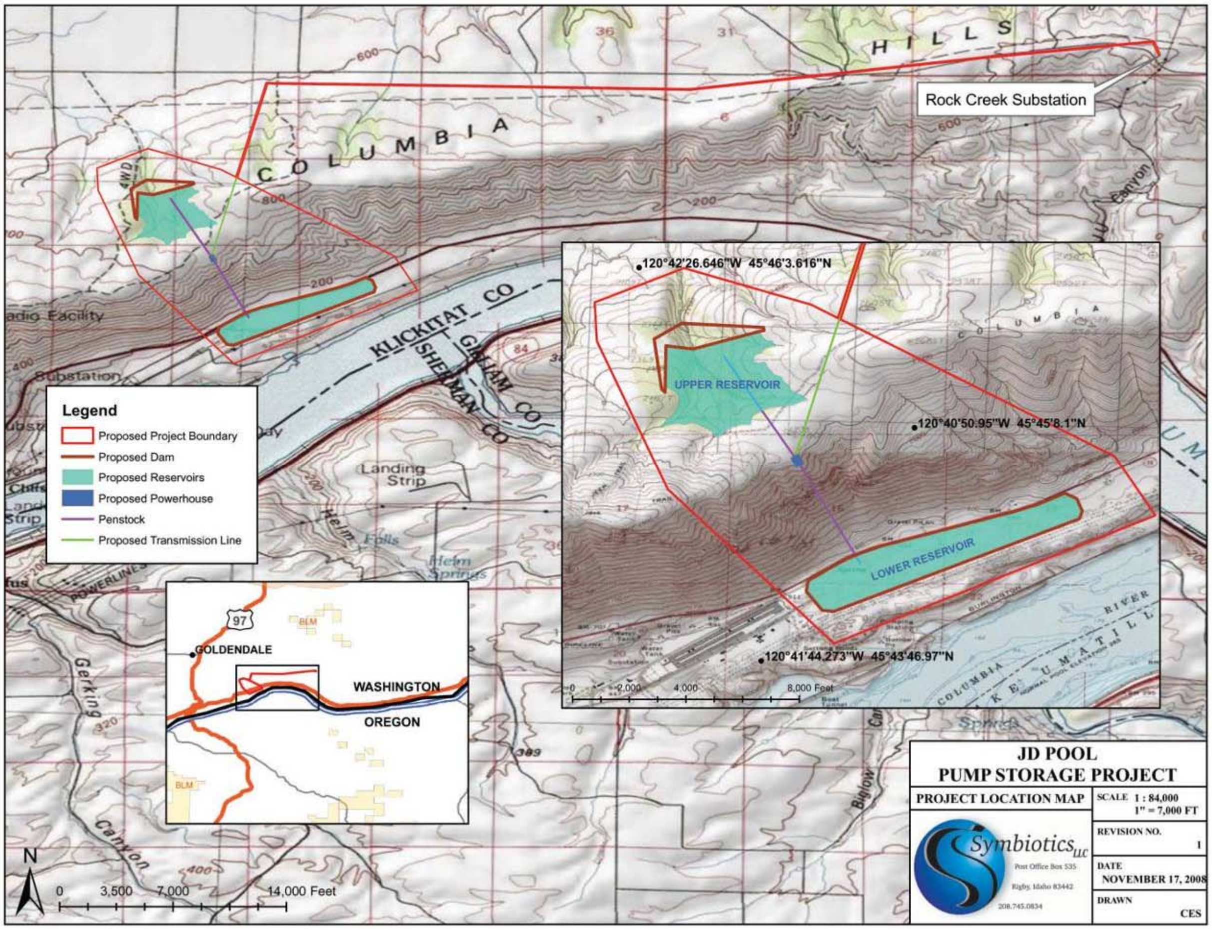

Figure 6- JD Pool Project Layout (JD Pool Preliminary License Application)

The project concept suggests a 230 kilovolt (kV) transmission line will interconnect with the existing Bonneville Power Administration (BPA) Rock Creek substation. The Rock Creek substation is 9.60 miles to the northeast. This project would be part of the Western Electricity Coordination Council market.

In the second six month progress report submitted to FERC as required under the Preliminary Permit, the permit holders obtained permission from the major landowner to conduct initial environmental studies. Preliminary negotiations have been conducted with landowner for purchase of the proposed project site. An agreement has been reached with the Washington State Department of Ecology for the planned use of water, and discussions with BPA reportedly have been conducted regarding the interconnection.

3.1.3.4 Parker Knoll

The Parker Knoll Pumped Storage Project (FERC No. 13239) is a proposed new development in southern Utah. The Parker Knoll Pumped Storage Hydroelectric Project is located in Piute County, Utah, about 31 miles southeast of the town of Richfield. The preliminary permit was filed on June 13, 2008 by Parker Knoll Hydro LLC and Symbiotics LLC, and the permit was issued on December 8, 2008. The Draft License Application (DLA) was filed by Symbiotics in June of 2011. The installed capacity of the project is expected to be 1,000 MW, and provide 2,630 gigawatt hours (GWh) of average annual energy production. The project as it is configured in the draft license application can generate 1000 MW for 10 hours and pump for 14 hours a day at 1,000 MW. It is anticipated that the facility will be capable of providing incremental and decremental reserves and load following services 24 hours per day.

A site layout from the DLA is shown in Figure 7. The upper reservoir will be impounded by two dams: a main dam and saddle dam. The upper main dam will be approximately 170 ft high with a crest length of approximately 1,650 ft, and the upper saddle dam will be approximately 50 ft high with a crest length of approximately 1,050 ft. The resulting reservoir will have a normal pool elevation of 9,600 ft MSL, and a storage capacity of approximately 6,780 ac-ft. The surface area of the reservoir will be approximately 110 acres.

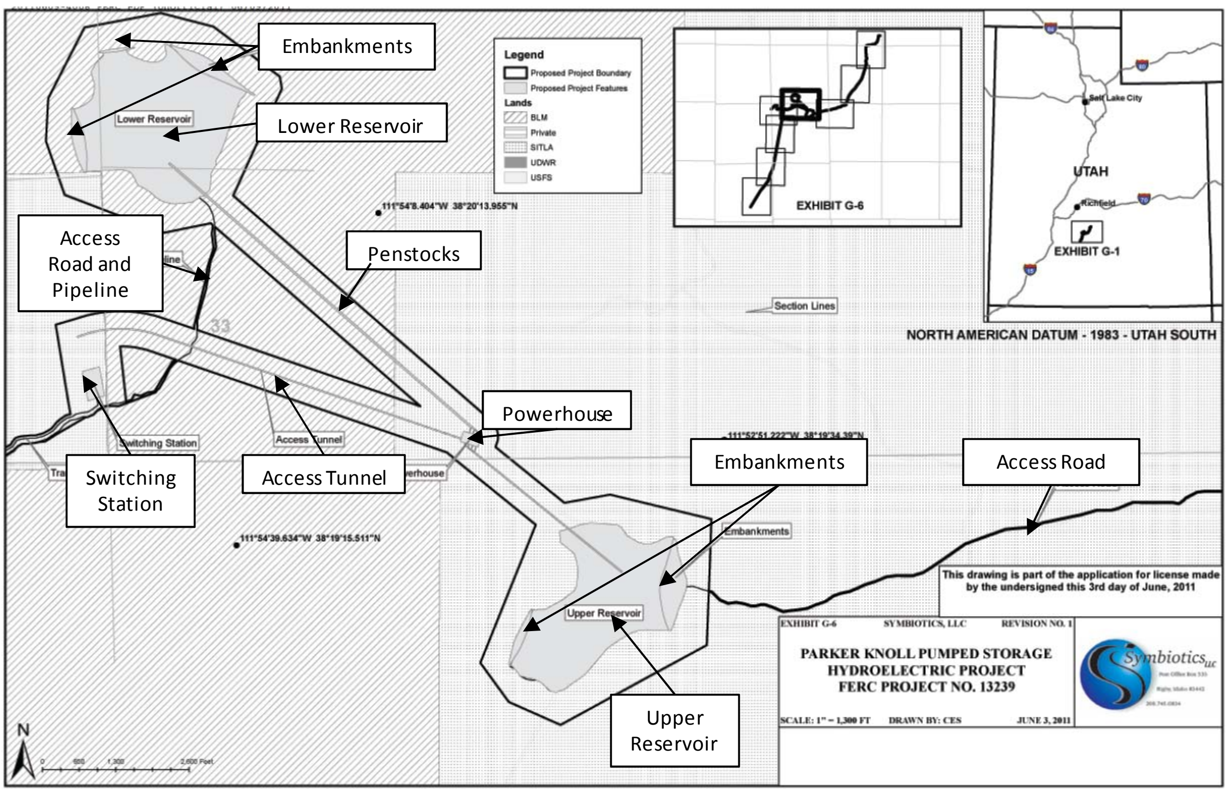

Figure 7- Parker Knoll Site Layout (Parker Knoll DLA)

The lower reservoir will be impounded by three dams: a main dam and two saddle dams (smaller dams to impound low areas around the rim of the reservoir). The lower main dam will be approximately 100 feet high with a crest length of approximately 1,750 ft. The first saddle dam will be approximately 80 feet high and have a crest length of approximately 1,150 ft, and the second will be approximately 20 feet high with a crest length of approximately 650 ft. The resulting reservoir will have a storage capacity of approximately 6,760 ac-ft and a maximum normal pool elevation of 7,650 ft. The reservoir will have a surface area of approximately 130 acres.

The project will have an overall conveyance length of approximately 12,800 ft with a 2,400 ft headrace tunnel, a 2,200 ft long vertical shaft, four 1,100 ft long penstock tunnels, and a 7,100 ft long tailrace tunnel. A surge chamber may also be included in the design.

A 1000 MW underground powerhouse will be constructed with four pump-turbine units. The underground powerhouse would also include isolated phase bus gallery, a transformer gallery, and a 7,150-ft-long, 26-ft-diameter access tunnel. Variable speed Francis type pump-turbines are under consideration for this project. Variable speed is considered to provide regulation capability in addition to the traditional ancillary services pumped storage provides during both pumping and generating, and to provide a broader operating range and flexibility.

Approximately 1 mile of new 345-kV transmission line will be built for the project. The 1 mile of new transmission line would extend from the proposed Parker Knoll substation to the existing 230-kV transmission line alignment. About 40 miles of 230-kV transmission line would be upgraded within the PacifiCorp system. Access options for the Parker Knoll site are relatively favorable. Access to the lower portion of the site could be provided from the existing Otter Creek Flat Road, near SR-62, and access to the upper portion of the site can be provided from the existing Black Point Road, near SR-24. Improvements to the existing roads will be required.

Potential environmental impacts were evaluated as part of the DLA. Unavoidable impacts include high summer flows between Otter Creek and the point of diversion during construction, permanently displaced vegetation, and the relocation of four individuals due to land inundation. The applicants are in the process of developing mitigation plans to combat these and other potential environmental impacts.

3.1.3.5 Swan Lake North

The proposed Swan Lake North Pumped Storage (FERC No. 13318) is estimated at 1,110 MW of installed capacity. The head is expected to fluctuate between 1,250 and 1,360 ft. The preliminary permit application for the Swan Lake North Pumped Storage Project was filed by Symbiotics LLC on December 12, 2008. The preliminary project was issued on April 28, 2009. According to the project website, the capacity of the projects has been increased to 1,380 MW.

There is however limited documentation regarding these capacity changes, and as such the data represented in this report is from the Swan Lake Preliminary Permit.

For the upper reservoir, an earth embankment with a clay core would be constructed. The dam would be 70 ft high and approximately 11,850 ft long. The resulting reservoir would be approximately 8,300 acre-ft with 260 surface acres. The lower reservoir would be approximately 8,820 acre-ft with 215 surface acres 80 ft high 8,000 ft long earthen embankment will be constructed. The proposed project would be filled from off-stream water sources. The proposed penstock is a 29-ft diameter, 5,860 ft long steel penstock connecting to a new 10 unit powerhouse. Subsequent to the original concept in the preliminary permit, the powerhouse configuration has been revised to a more typical four unit layout.

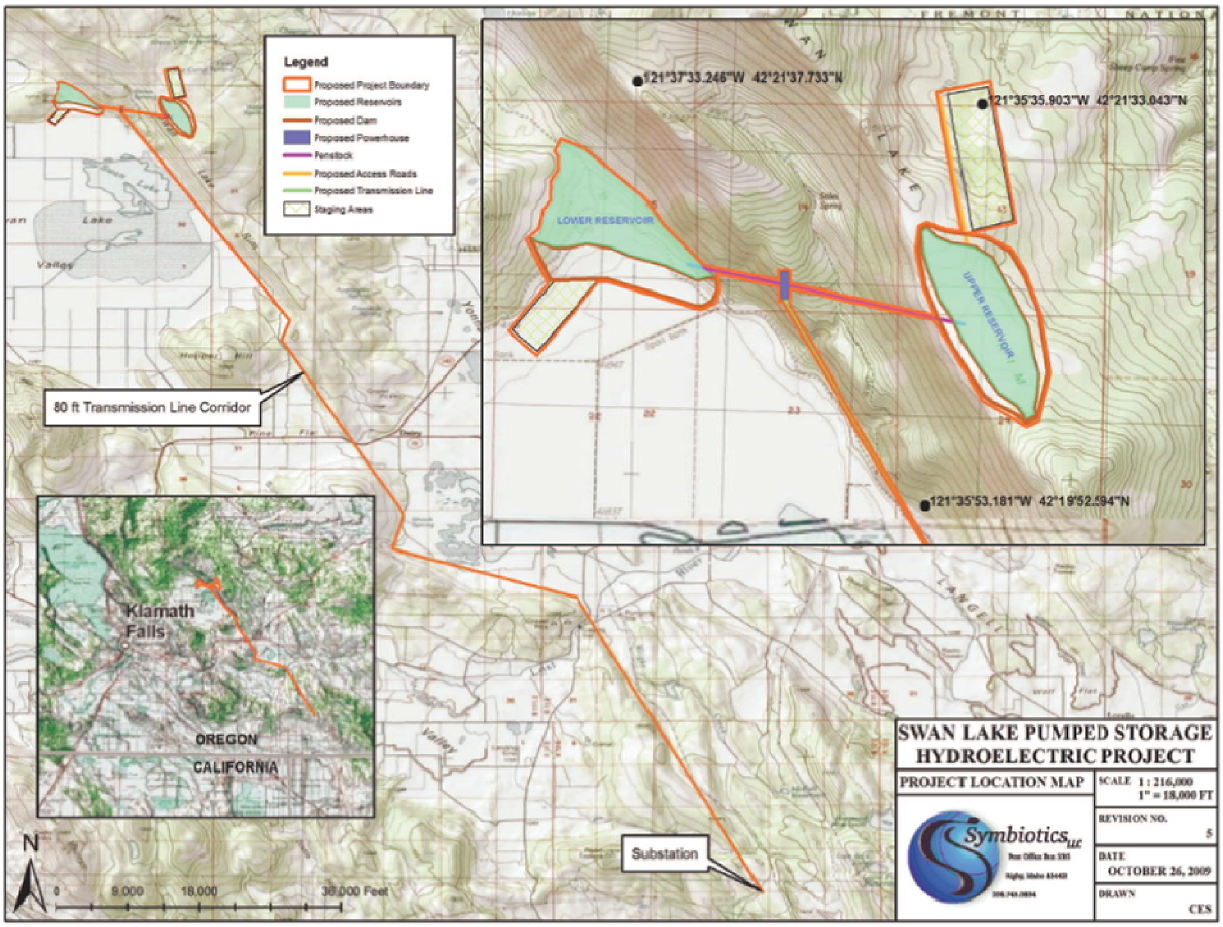

Figure 8- Swan Lake North Site Layout (Swan Lake Pre-Application Document)

The proposed 500 kV line would traverse 12.5 miles will connect with a proposed upgrade to an existing 500 kV lines owned by PacifiCorp an additional 500 kV line owned by BPA is located in the area. The project would inundate US Bureau of Land Management administered lands as well as potentially impacting lands with construction of the powerhouse. Transmission lines would also cross US Bureau of Land Management lands. Additionally, there are significant archaeological resources in the vicinity. The economic analysis for this project is ongoing.

Geotechnical studies have been ongoing, and meetings have been held with the Bureau of Land Management to discuss the parallel environmental assessments and preconstruction geotechnical work. Second stage transmission interconnection studies are in process. A public meeting has been scheduled to discuss the transmission alternatives. Groundwater studies were completed this spring and modeling work is scheduled. In addition, vegetation characterization and weed assessment surveys, sensitive plant surveys and sensitive wildlife habitat evaluations have been completed.

3.1.4 *Performance Characteristics*

Pumped storage hydro plants can provide load balancing and shifting (often called energy arbitrage) and historically have done so by pumping during night time hours and on weekends, and then generating during periods of higher demand. A pumped storage project would typically be designed to have between 6 to 20 hours of hydraulic reservoir storage for operation at full generating capacity. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value. Existing pumped storage projects range in capacity from 9 to 2700 MW, and in available energy storage from 87 MWh to 370,000 MWh of storage.

Pumped storage projects also provide ancillary benefits such as firming capacity and reserves (both incremental and decrimental), reactive power, black start capability, voltage stability and frequency support. In the generating mode, the turbine-generators can respond to frequency deviations extremely fast just as conventional hydro generators can, thus adding to the stability of the grid. In both turbine and pump modes, generator-motor excitation can be varied to contribute to reactive power load and stabilize voltage. When neither generating nor pumping, the machines can also be operated in synchronous condenser mode, or can be operated to provide “spinning reserve”, providing the ability to quickly pick up load or balance excess generation. Grid-scale pumped storage can provide this type of load-balancing benefit for time spans ranging from seconds to hours with the digitally controlled turbine governors and large water reservoirs for bulk energy storage.

The traditional mode of operation of a pumped storage plant is to begin pumping in the evening after the peak load hours of the day, and continue pumping through midnight and into the early morning hours when low-cost pumping energy is available from base load units, and then change modes to generate power during daytime peak periods when energy values are highest. The pump-turbines are gradually taken off line in the morning hours as load ramps up, and then are usually put on line as generators. The rest of the generating system (and the transmission system operator) sees a balanced and easily followed load curve. This daily cycle is routinely followed during the work week. On weekends, when the electrical demand is usually less, there is more low cost pumping energy available and the units typically operate in the pump mode or are off, depending on system load conditions. In a weekly cycle, the upper reservoir is full at the beginning of the work week, at its lowest point at the end of the work week, and returns to full upper reservoir conditions during the weekend's pumping operations.

Pumped storage can be of great advantage in the shorter balancing authority time frames, within the hour, minute, or even real-time, to provide incremental and decrimental reserves. One advantage is the ability of pumped hydro to store energy when surplus energy is being produced by wind-powered generators, typically at night when overall energy demand is low. A synchronous-speed (i.e., single-speed) pump-turbine in pumping mode has a fixed relationship of power input requirement to net head; therefore, the power input to the pump-turbine cannot change while it is on line. Existing pumped storage projects therefore utilize "blocks" of excess energy off the grid for pumping operations. With the advent of variable speed technology pumped storage units, load balancing in the pump mode can be a very significant grid benefit by providing critical decrimental and frequency regulation reserves, thus smoothing the supply curve. In off-peak periods where the pumped storage station may be in pumping mode, the level of pumping could vary based upon the expected output in wind energy. The pumps could adjust their input power to smooth out the wind output by reducing pump load as wind drops off and increasing pump demand when wind output picks up in real time. In the on-peak periods when the pumped storage station is generally in generating mode, the actual output of the pump-turbines could be adjusted such that the wind plus the pump-turbine output is smoother within the minute or hour to minimize load change impacts on other units in the area. In the generation mode, the capabilities of both single and variable speed machines are identical to conventional hydropower units. By varying the wicket gate position to be between 60 to 100 percent, the units can provide incremental and detrimental reserves via load-balancing at partial load and provide Automatic Generation Control (AGC) services.

A typical pumped storage plant is designed for more than 50 years of service life, but many projects that were constructed in the 1920's and 1930's are still operational today. A generator-motor rewind or upgrade can be expected after approximately 20 years of service, but the pump-turbine equipment can last for a longer period of time and may only be elected for an upgrade when the efficiency gains of modern equipment justify the expenditure.

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 will require a 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.

Environmental and licensing concerns may include fisheries issues (e.g. entrainment or passage concerns), deforestation, recreation, and land use concerns. For closed-loop systems, there is no water discharged from the station into the main-stem river after the initial tunnel and reservoir fill (under controlled conditions), and fish entrainment and impingement is thereby avoided. Equipment can be selected to further protect fish, and the techniques for protection of aquatic species are generally the same as applied for large hydroelectric projects. With respect to pristine forest environments, 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, etc., 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 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 data base, one could expect the direct cost of a pumped storage facility utilizing single speed unit technology to be in the order of $1,500 to $3,000 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 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.

3.1.6.2 Annual Operation and Maintenance (O&M) Costs

Operation, maintenance, and outage costs vary from site to site dependant 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:

O&M Costs ($/yr) = 34,730 x C0.32 x E0.33

Where: C = Plant Capacity, MW

E = Annual Energy, GWh

This methodology is considered valid and an escalation factor of 2.0 is recommended going from 1987 to 2011. 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.

For a 1,000 MW pumped storage project generating 6 hours per day 365 days per year, and annual energy production of 2,190 GWh. The calculated annual O&M costs are approximately $8 million in 2011 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, $250,000 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 reinsulation of the stator and rotor, typically 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 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 electric load connected to said battery and finally return to the positive electrodes (anodes) for electrochemical reduction. This basic direct current (DC) current, through ancillary power electronics, is inverted into the desired frequency and voltage.

Certain battery technologies have significant exposure in various markets including telecom, end-user appliance, 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. Battery systems were estimated to account for 451 MW or 0.4% of total energy storage capacity globally in 2010.[3]

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)
- Nickel cadmium (NiCd)
- Nickel metal hydride (NiMH)
- Family of lithium ion chemistries (Li-ion)
- Flow
    - Vanadium redox battery (VRB)
    - Zinc bromide (ZnBr)
    - Polysulfide bromide (PSB)

[3] Electricity Advisory Committee (EAC). Energy Storage Activities in the United States Electricity Grid. May 2011.

- Hydrogen bromide (HBr)

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

3.2.2 Manufacturers and Commercial Maturity of Technology

All of these batteries have the technical potential for penetration into specific utility markets and applications. Technologies such as PSB and HBr flow batteries have not reached market commercialization and are currently in various stages of research and development. Lead acid battery technology, although mature and ubiquitous in application, was not studied in this report due to its limited life cycle when performing at high depth of discharge levels, heavy weight and relatively lower specific energy content.

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 technologies systems is presented. The five manufacturers included in this study, based on their involvement in utility-scale energy storage systems, are[4]:

- [5]Lithium ion (Li-ion) - A123 Systems, Inc. (A123)
- Sodium sulfur (NAS) – NGK Insulators, Ltd. (NGK)
- Vanadium redox battery (VRB) – Prudent Energy Corporation (Prudent)
- PowerCells™ – Xtreme Power, Inc. (Xtreme)
- Zinc bromine (ZnBr) – Premium Power Corporation (Premium)

[4] Manufacturers or representatives were directly contacted by HDR through e-mail and telephone. 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. HDR does not: (a) make any warranty or representation, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information furnished by these manufacturers or (b) assume any liabilities with respect to the use of, or for damages resulting from the use of, any information, method or process disclosed by manufacturers captured in this report.

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The list above is not comprehensive and other potential manufacturers in early stages of commercialization include the following:

- Lithium ion (Li-ion) - Altair Nanotechnologies, Inc. (Altair)
- Zinc bromine (ZnBr) – RedFlow Limited (RedFlow)
- Zinc chloride (ZnCl) – Primus Power Corporation (Primus)
- Zinc Air (ZnFe) – Zinc Air, Inc.

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:

LixC + Li1-xCoO2 <-> LiCoO2 + C

Li-ion batteries are known for having high energy density and low internal resistance, making efficiencies upwards of 90% possible very attractive for power quality utility and mobile applications. An external heating or cooling source may be required depending on ambient conditions and system operation. This technology is classified as commercial because it has been implemented in the utility markets.

Figure 9- A123 Li-ion Cells

Figure 10- 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. In the discharge cycle, the positive sodium ions pass through the electrolyte and combines 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 330degs. 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. 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.

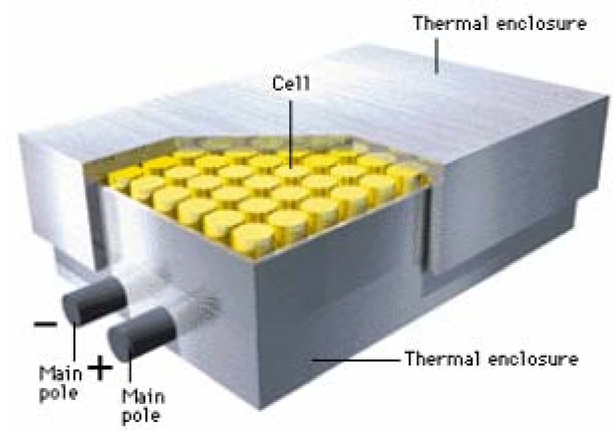

Figure 11- NAS Cell Module

Figure 12- 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:

Anode: $V^{5+} + e^{-} <-> V^{4+}$

Cathode: $V^{2+} <-> V^{3+} + e^{-}$

VRB systems are recognized for their long service life as well as its ability to provide system sizing flexibility in terms of power and energy. VRB efficiency tends to be in the range of 70-75%. The separation membrane prevents the mix of electrolyte flow, making recycling possible. This battery technology is classified to be in its nascent commercialization stage as there has been only a handful of utility-scale implementation, although the technology itself has been in development for 20 years.

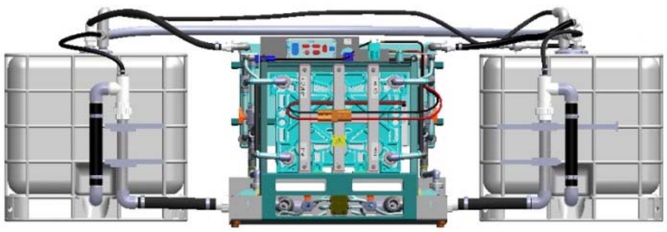

Figure 13- VRB Cell Stack and Electrolyte Tanks

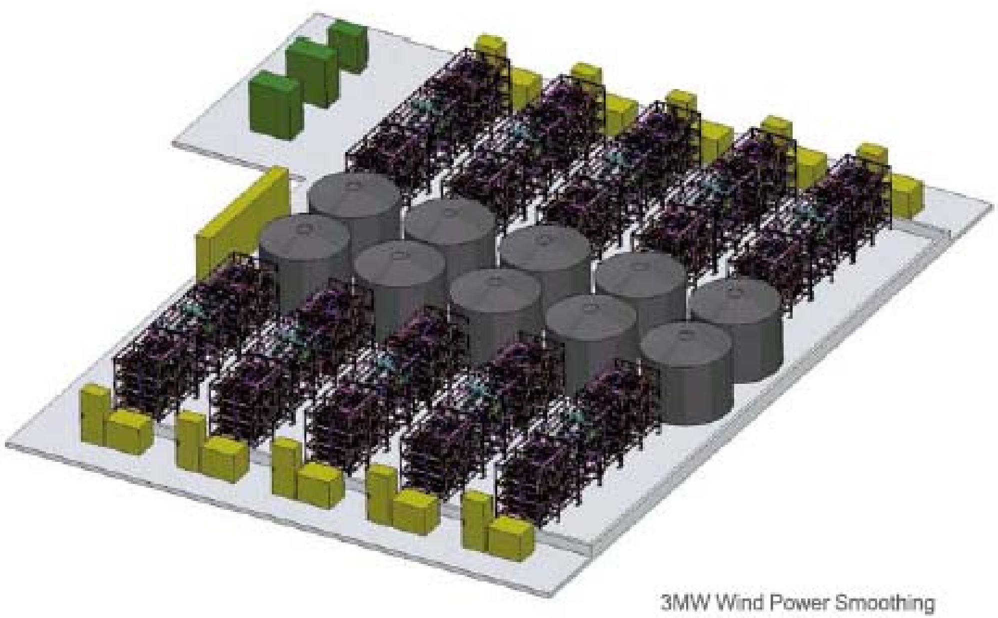

Figure 14- Standard VRB Plant Design 3 MW

3.2.2.4 PowerCell™ – Xtreme Power, Inc. (Xtreme)

PowerCells™ 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.

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.

Figure 15- PowerCell™ Stacks with PCS

Figure 16- 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 compartments 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 its long service life and its flexibility 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. Like the VRB systems, ZnBr battery technology is considered in its early stages of commercialization given its numerous test facilities. 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 18 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 17- ZnBr Cell Stacks

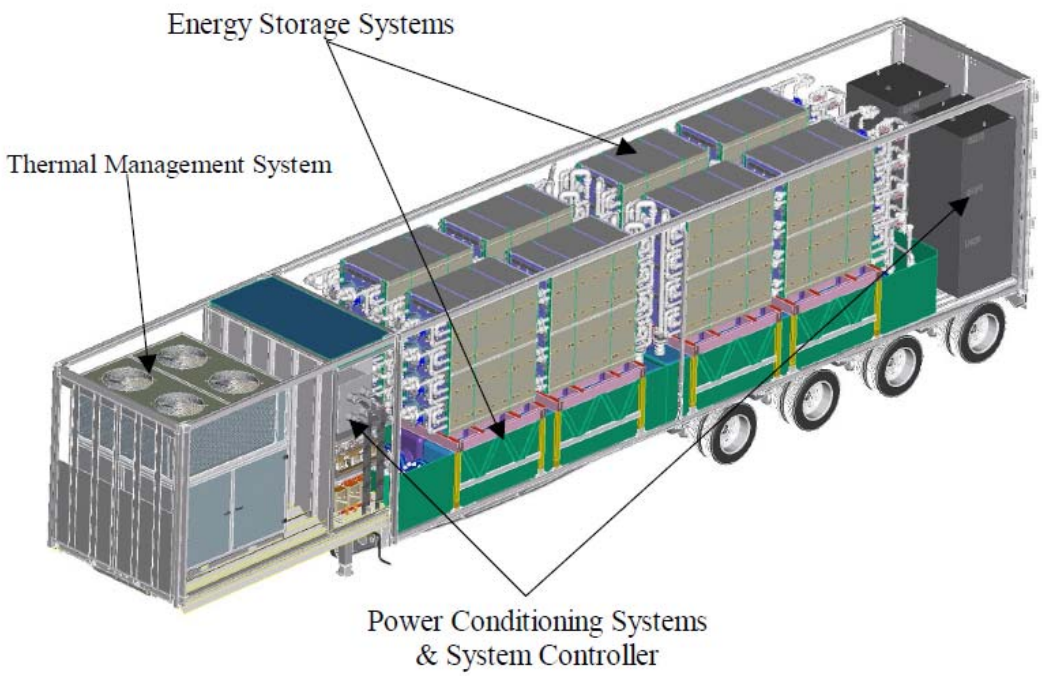

Figure 18- Premium's TransFlow2000 Section (ZnBr battery)

3.2.3 *Summary of Manufacturer Data:*

The following table and chart summarizes applications of battery storage systems that have been operating or have been contracted to complete installation in the US provided by the five manufacturers. Data sets do not include any sales projections or forecasts, and only include data points of projects implemented, or projects breaking ground. This data is proprietary and as such is only summarized at a higher level for the purposes of this report.

Data sets from these five manufacturers may provide an approximate indication of battery industry and should not be construed as accurate predictions of industry / market behavior for the simple reason that data collected is not all inclusive of a few other commercialized manufacturers, 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)[6].

Table 4- Projects Breakdown by Type and Capacity

Application	Number of Projects	Total MW Capacity	Total MWh Capacity
Renewables Integration	19	218.6	337.6
Power Quality	13	43.1	49.7
Load Management	14	18.0	84.9
Totals	46	279.7	472.2

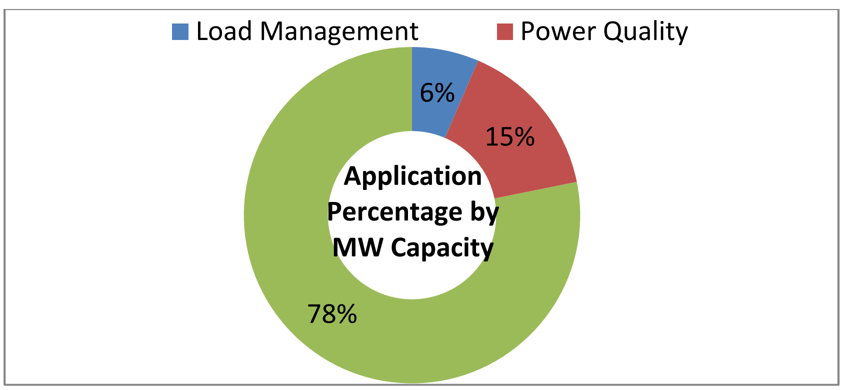

Figure 19- Projects Breakdown by Percentage[7]

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

[7] All data points on the number of projects, system sizes and capacities were compiled from manufacturers only for projects in the US. Also note that HDR did not locate any publicly-available information on Premium ZnBr's projects, the number of projects and sizes of installations were furnished by manufacturer.

A few notable highlights of the data sets include the following:

- Load management applications are comprised of NGK, Xtreme, Prudent and Premium. NGK claims majority share with 78% of MW capacity.
- Power quality applications are comprised of A123, NGK, Xtreme and Premium. A123 claims majority share with 65% of MW capacity.
- Renewables integration applications are claimed by all five manufacturers. Xtreme claims majority share with 76% of MW capacity.
- A few other observations made include:
    - A123 projects are focused on renewables firming and ramp management, frequency regulation, 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.
    - NGK projects are focused on island / peak shaving applications, and solar integration. Projects in their portfolio are multiple-hour systems.
    - Prudent projects are focused solar and wind integration, and island / peak shaving. Projects in their portfolio are multiple-hour systems.
    - Xtreme has the highest MW capacity of wind integration in the battery market and ramp control projects. They also work with solar integration and offer peak shaving / load leveling. Projects in their portfolio range from sub-hourly to multiple-hour systems.
    - Premium is focused on power quality, island / UPS and on peak shaving / load leveling projects. Projects in their portfolio are multiple-hour systems.
    - In almost all instances, load management services also offer UPS services, and may be coupled with islanded grid operation in tandem with an external generator.

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

- 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 computation include the conversion and storage efficiency of each technology (e.g. voltaic, coulombic, chemical losses), PCS and transformer losses, and any auxiliary losses of support equipment (e.g. pumping, cooling, heaters, etc.).

It is also important to distinguish the fact that the performance characteristics are generally driven by application requirements – li-ion and dry cell systems have significantly higher roundtrip efficiencies than that of NaS or flow batteries. These two technologies also compete with the flywheel technology in the regulation markets, due to similar support times. However, in terms of applications, it is the NaS and flow batteries that are generally recognized to provide 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 (especially during idle time), li-ion and dry cells have the lowest self-discharge rate.

3.2.4.2 Energy Footprint

The energy footprint of battery systems varies considerably, from a few hundred square feet to a few thousand square feet 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, to a certain degree of flexibility, the physical constraints (e.g. placing systems in electric utility closet rooms, basements). Solid-state technologies like the li-ion, dry cells and NaS will have better energy footprint against flow battery technologies.

HDR advises to use caution when interpreting energy footprint (square feet per MWh) metrics – 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 to be dedicated to auxiliary and support equipment (i.e. 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.

It is anticipated that the solid-state battery technology's energy footprint will scale more linearly than 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 plant dimensions:

- Premium 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. Case in point, 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 (or vice versa) make up one cycle. The solid state batteries generally have a relatively shorter expected life than flow batteries.

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 DPR™ cell curve is used as an example of exponentially-changing number of cycles at various DOD:

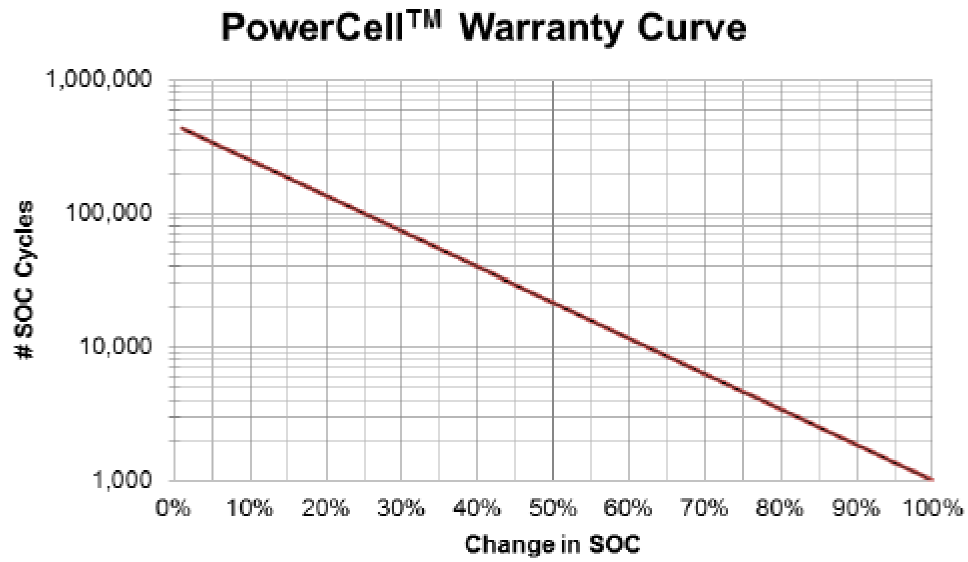

Figure 20- Typical Battery Life Cycle Curve State of Charge (SOC)

Note that plant life claimed by manufacturers is a compendium of engineering projections, laboratory testing, and some data points are empirical from field service of battery plants. The flow battery systems claim an indefinite amount of cycles for its system, 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.

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.

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 system. Li-ion systems are generally not suited for quick discharges because it results in generation of immense amount of heat.

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 five 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 containerized trailer system, but it is anticipated that their modular MW-block solutions will also require housing structures.

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 or deadband could not be ascertained. Auxiliary heating is required in 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 in temperature 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. 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 Technology Matrix in Appendix A.

3.2.6 *Technology Risks*

Each battery technology shares a certain amount of risks associated with installation and operation. NGK's NAS systems require a heating source when running idle. 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 and will be prohibited by sands within the module case. Xtreme's battery system is generally limited to 50% DOD. 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 (PE) 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. Cost numbers do not reflect any site civil development costs and does 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. 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 changeout 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 standard part, off the shelf, component or equipment changout (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 costs include the cost of unexpected failures and irregular equipment performance. This will likely be, but not limited to, the diagnosing, investigation and testing of components, and the subsequent costs for corrective action. As an example, inverter fan filters and PCS may fail prematurely.

All cost and maintenance data provided by manufacturers are summarized in Technology Matrix in Appendix A.

3.3 Compressed Air Energy Storage (CAES)

3.3.1 *CAES Technology Description*

A Compressed Air Energy Storage Plant (CAES) 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 a couple of plants are currently in operation, including Alabama Electric Cooperative's (AEC) McIntosh plant 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. Other CAES plants have been proposed but, as of yet, have never moved forward beyond conceptual design. These proposed projects include the Norton Energy Storage (NES), the Iowa Stored Energy Park (ISEP), and the Western Energy Hub Project. The Western Energy Hub project is probably the most advanced CAES project under development in the U.S. The geology has been well characterized, as well as land acquisition and local and state permitting underway. The NES Project has been purchased by First Energy. The proposed project will have an initial capacity of 270 MW, and can be expanded to a 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. The Iowa Stored Energy Park has recently terminated its progress due to the recent conclusion that the geology was not favorable to CAES.

3.3.1.1 Technology Risks

CAES has performed very well at the AEC McIntosh plant and therefore little risk is perceived with this technology 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 significant integrity and accessibility.

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 include a higher overall pressure ratio in the gas turbine, an improved recuperator design, and improvements in compressor efficiency. However, these improvements have not been proven on a commercial scale application that is in operation. The expected turbine heat rate at the generator terminals (excluding plant auxiliary loads, mechanical losses and other miscellaneous losses) is estimated to be under 4,300 Btu/kWh (HHV) and the turbine design has a gross generator output of around 137 MW at ISO conditions when utilizing a 21,500 Btu/lb (LHV) natural gas fuel. Two sets of combustors are utilized in the turbine design. The high pressure combustors require a 935 psia inlet gas pressure and consumes approximately 20 percent of the fuel and the low pressure combustors require a 340 psia inlet pressure and combusts 80 percent of the fuel.

Site elevation does impact the performance characteristics of a 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 ration 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 ft 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 depicted in the Technology Summary Matrix at both sea level and at 6,000 ft elevation assuming identical plant equipment, cavern sizes and dispatch schedule (i.e. compression period and power generation periods are identical). The plant capital cost is increased due to larger compressors. Additionally, the plant output is increased as a result of the lower turbine exhaust pressure at higher altitudes. Overall, the electrical turnaround efficiency is lower at altitude, though, as a result of increased compressor sizes and increased losses during compression due to a greater compression ratio. The plant size assumes four approximately 135 MW gross power blocks. Alternatively, Alstom has marketed a single 300 MW power block.

3.3.2.1 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.

3.3.2.2 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.

3.3.2.3 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.

3.3.2.4 Air Quality Control System Design

Dry low mono-nirogen 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 21 depicts the aforementioned geological formations generally considered for compressed air energy storage.

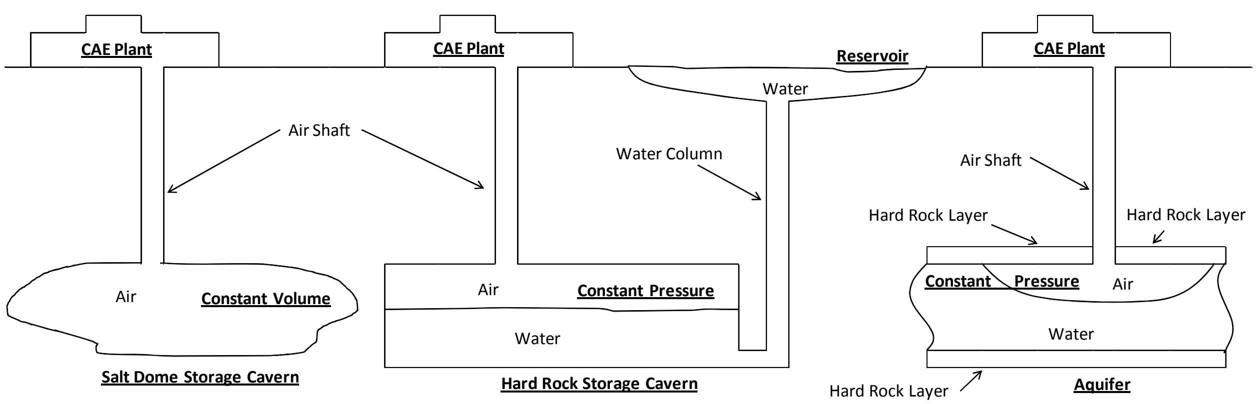

Figure 21- CAES Geological Formations

Figure 22 depicts an overall map of the continental United States with areas that contain potential geological formations favorable for CAES.

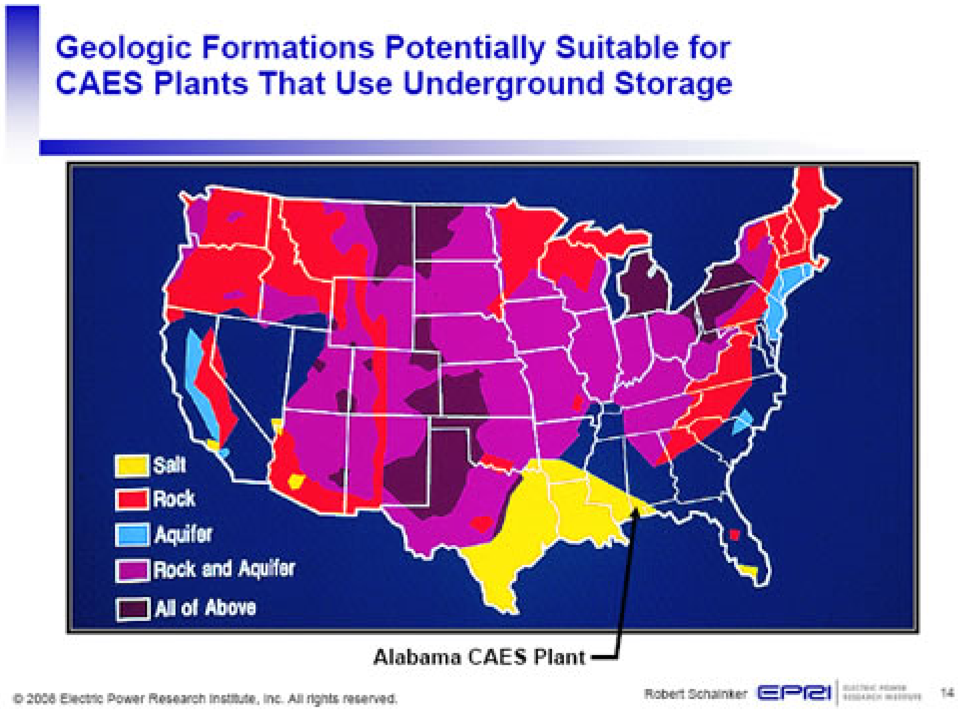

Figure 22- Potential Geological Formations Favorable for CAES.

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 cavern must be drilled, mined and debrined, such as a salt dome, 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 5.

Table 5- 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 formation 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 and rock caverns are the most expensive storage formations since mining is necessary before storage. In general, rock caverns are about 60% more expensive to mine than salt caverns, for CAES purposes, due to the excavation of underground solid rock versus solution extraction of salt. 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 formations that require mining 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 $590/kW. ISEP was estimated previously at approximately $221 million to build at a plant size of approximately 268 MW, which correlates to a project cost of approximately $825/kW. ISEP has not publicly released information regarding the quantity of storage it is projecting for ISEP.

Table 6- ISEP Project Cost

Task	Est. Cost
Test well	$1.5 million
Preliminary design	$.5 million
Permitting	$2 million
Final design	$3 million
Construction	$214 million
Sum of Tasks	$221 million

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 $1,200/kW to $1,800/kW for a 300 to 500 MW CAES plant with ten hours of storage capacity. 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 indirects. Values are presented in 2011 dollars.

Ideally, the storage cavern utilized for the project would already be available, but in the case that it isn't, then the cavern would require mining. Costs for solution mining a salt cavern are estimated to be $15 to $20 million for a single 135 MW application utilizing the Dresser Rand Technology.

3.3.4.2 Operating Costs

Operating costs are presented in the Technology Summary Matrix in Appendix A and are broken down into fixed O&M and variable O&M 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 the fixed portion of major parts and maintenance costs, spare parts and outsourced labor to perform major maintenance on the installed equipment.

Variable O&M: Variable costs include the cost of charging the energy storage system. For charging of the CAES system, it has been assumed that off-peak electricity is available at a cost of $40/MWH.

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 in the application of supplying backup power in a power outage event, regulating voltage and frequency.

3.4.2 *Manufacturers*

A quick market survey of the energy storage industry reveals that there is one flywheel technology manufacturer that has achieved utility market commercialization: Beacon Power Corporation with their Generation 4 Flywheels. Other prominent flywheel manufacturers – Pentadyne Power Corporation, Hitec Power Protection, Inc. and Active Power, Inc. only serve the commercial and industrial markets in the back-up power industry.

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. Energy content in a flywheel can be characterized as follows:

$$E = 0.5Iw^2$$

Where E is the amount of kinetic energy stored, I is the moment of inertia (mass-related property) and w is the rotational velocity. Conceptually, the moment of inertia can also be understood as an object's resistance to movement in a specific direction – the heavier an object, the higher its moment of inertia. Low-speed, high-mass flywheels (relying on I for energy storage) are typically made from dense metal such as steel, aluminum, or titanium; high-speed, low-mass flywheels (relying on w for energy storage) are constructed from composites such as carbon fiber.

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

Beacon has been instrumental in the development of the flywheel technology, and has a history of pioneering Generations 1 through 3 flywheels in commercial deployment. They are currently targeting to deploy Generation 5 flywheels, with improved energy performance, by the second half of 2012. Beacon offers its flywheel technology and balance of system plants as the Smart Energy 25 product. In the fourth quarter 2011, the company entered bankruptcy protection. and the company offers turn-key solutions in the US and Europe, and also provides in-house operating and maintenance services.

Figure 23- Smart Energy 25 100 kW / 25 kWh

Figure 24- Flywheel Plant 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. The aluminum hybrid hubs fatigue, after considerable cyclic mechanical stress, and around year 20 may require replacement.

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 being constructed 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.

Much of the firm's experience can be linked back to energy research and development while part of SatCon Energy Systems Division. Since then, Beacon's technology has evolved slowly and steadily from the energy storage for telecom applications to UPS systems and now for utility grid operations.

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 the following:

- ARRA 2009 (see Appendix B) - The 20 MW Beacon flywheel plant is estimated to cost $48,127,957. This yields $2,406 per installed kW.
- Sandia research paper – High speed composite flywheel system costs were estimated to be the additive of $600 per kW plus $1,600 per kWh.

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.

Beacon offers in-house, contracted maintenance services as well as product warranties. The term for a standard warranty is 12 months from equipment start up and acceptance test. An extended warranty is available, recurring annually at 3% of installed capital costs. While under warranty, any servicing and component defects will be handled by Beacon's field team. The forced outage rate of its power system is estimated to be 2% of the time, although this also depends on how each individual flywheel is sequenced to operate in a flywheel plant.

All cost and maintenance data provided by manufacturers are summarized in Technology Matrix in Appendix A.

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	Compressed Air Energy Storage	Batteries	Flywheels
Range of power capacity (MW) for a specific site **(For pumped storage, four sites were considered within the PacifiCorp footprint)**	255-1130	100+	1-32	1-20
Range of energy capacity (MWh) **(For pumped storage, four sites were considered within the PacifiCorp footprint)**	2,550-11,300	800+	Variable depending on DOD	0.25-5
Range of capital cost ($ per kW)	$1,500-$3,000	$1,400-$1,700	$450-$4,000	$2,400/kW or $600 per kW plus $1,600 per kWh.
Year of first installation	1929	1978	1995 (sodium sulfur)	2007

Comments on the overall commercial development of the technology, the applications that each technology is suited to, space requirements for each technology, performance characteristics, project timelines, and capital, operating and maintenance costs have been made to aid PacifiCorp in its IRP considerations.

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).

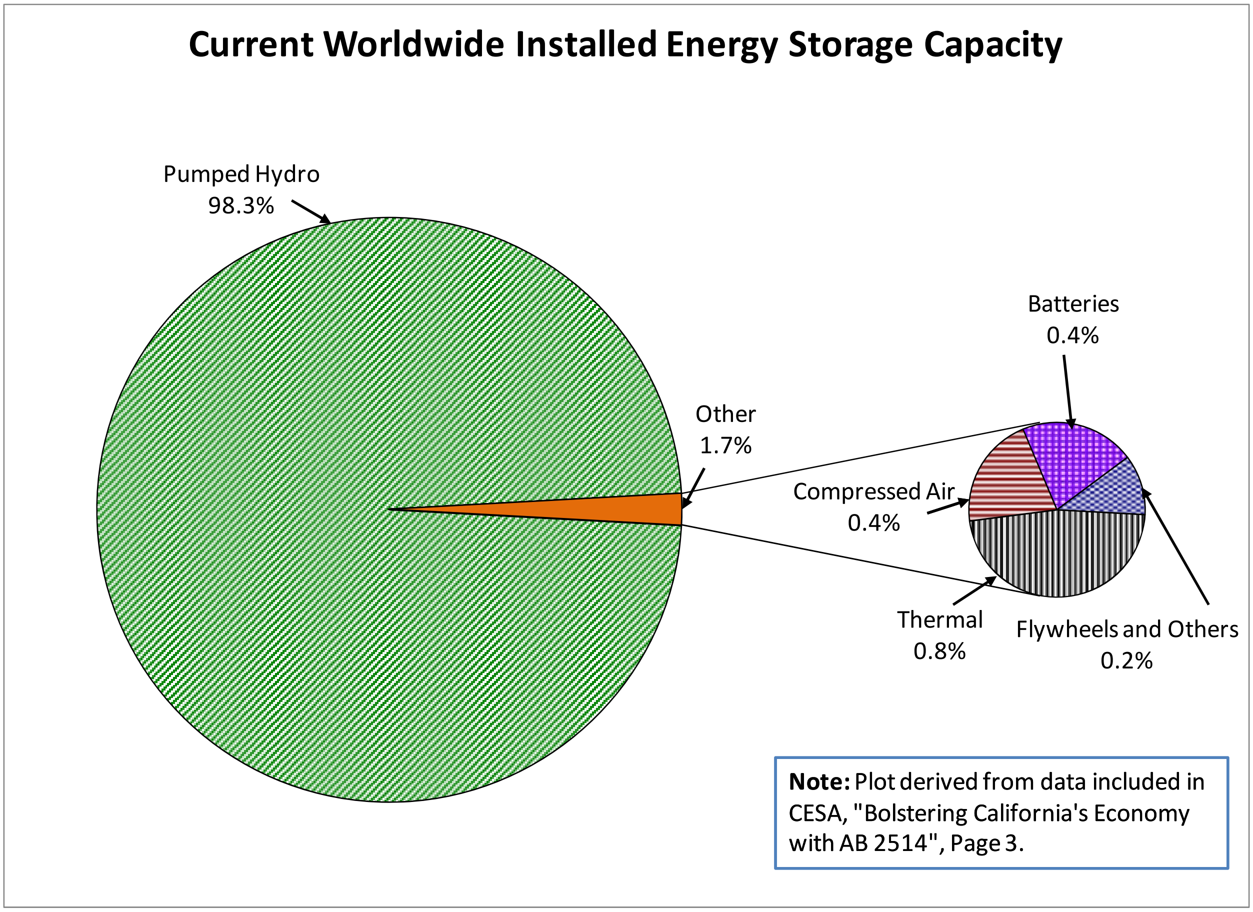

Figure 25- Current Worldwide Installed Energy Storage Facility Capacity (Source: CESA)

4.2 Applications

CAES and Pumped storage 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 is somewhat less in acreage than a Na-S battery field, and far less than that of a Li-ion field, when including the area of the reservoirs. 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 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

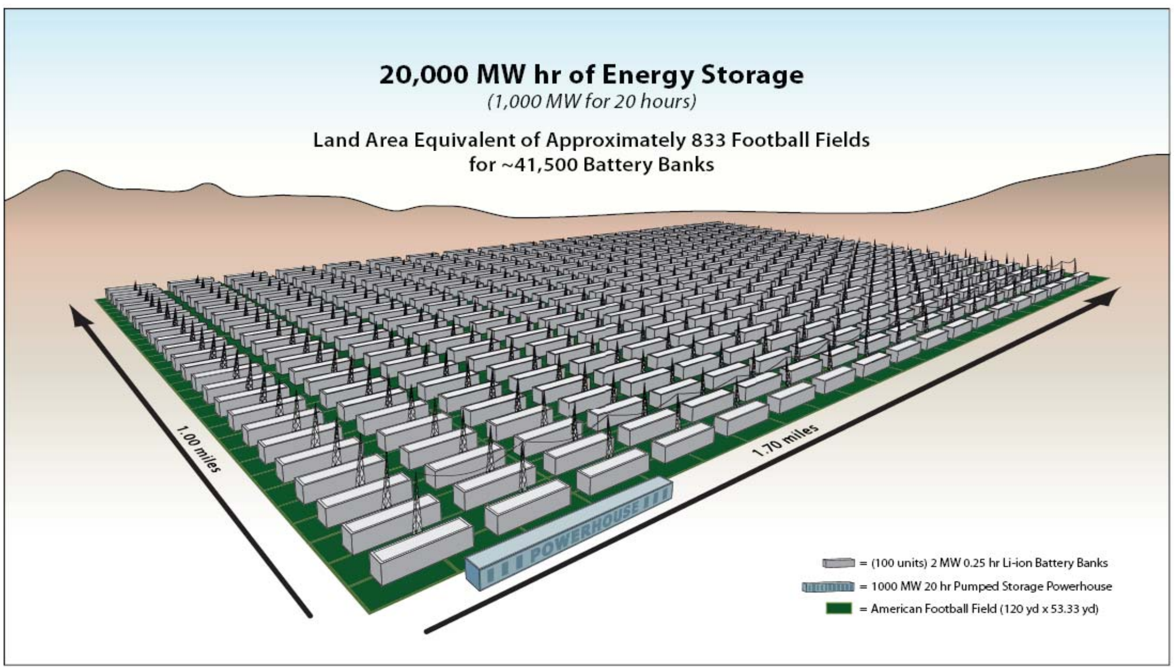

Figure 26 Li-ion Battery Field and a Hydroelectric P/S Plant for 20,000 MWh of Storage (Source: HDR)

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 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.

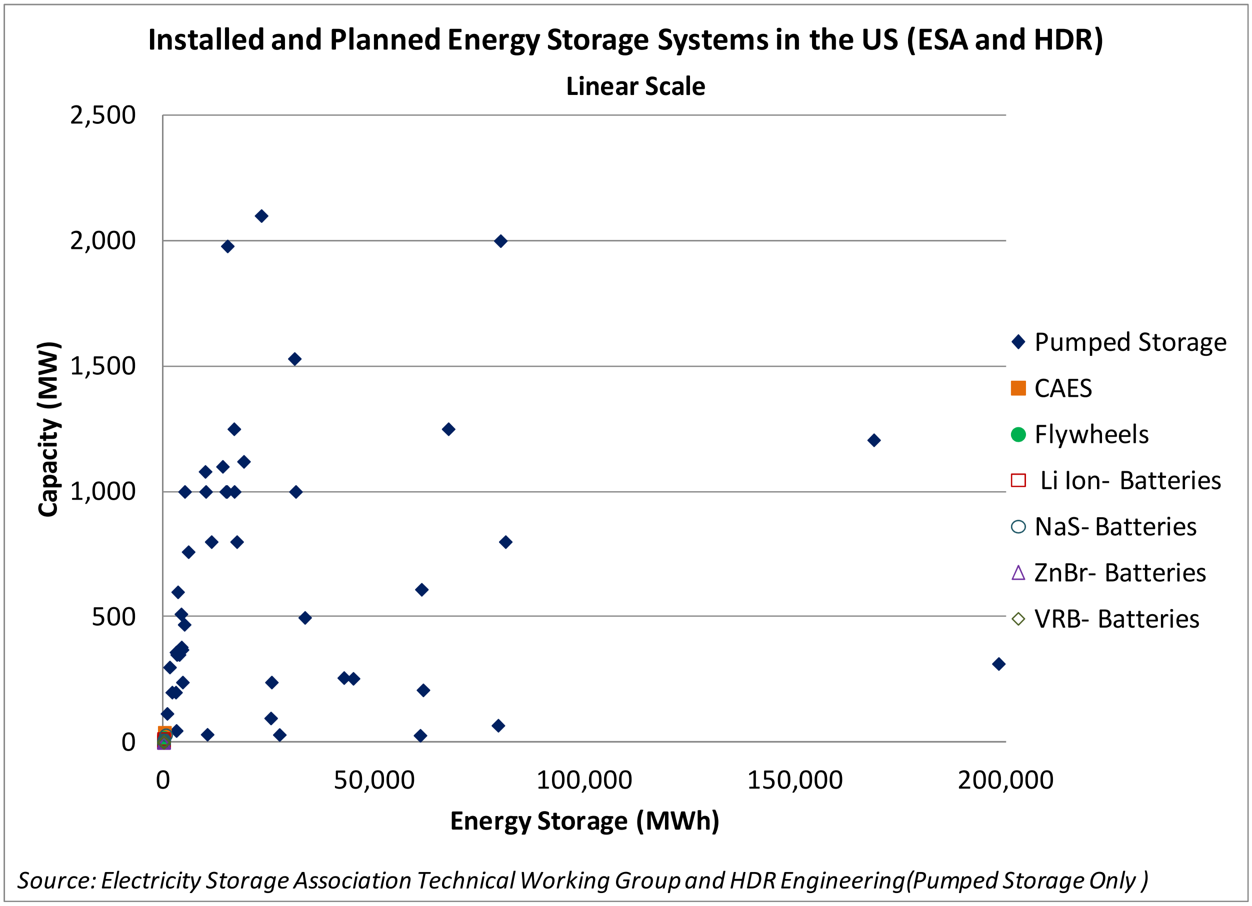

Figure 27- Current Energy Storage Technology Capabilities in Real Time (Source: HDR)

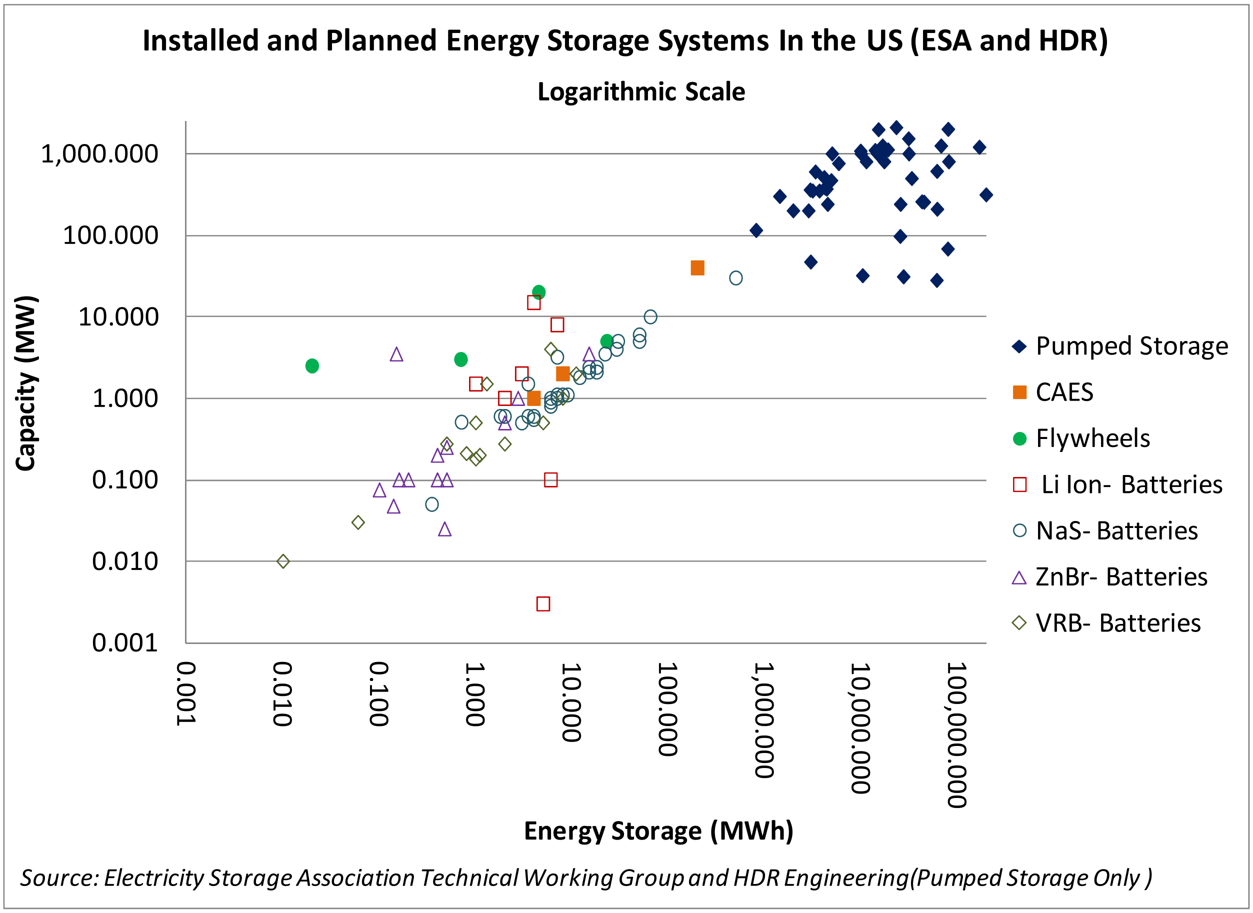

Figure 28-Current Energy Storage Technology Capabilities (Log-Log Scale) (Source: Electricity Storage Association)

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. 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 combination 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 B. While these plots are 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

	Beacon Power Flywheel	A123 Li-Ion	NGK NAS	Prudent VRB	Xtreme Dry Cell	Premium ZnBr	Pumped Storage	CAES
System Cost ($/kW and/or $/kWh)	$600 per kW plus $1,600 per kWh (Sandia) $2,406 per kW (ARRA)	$900 (High Power) $1,100 (High Energy)	$4,000 per kW	$644 per kWh	$1,800 - 2,000 per kW	$200 -300 per kWh plus $250 - 350 per kW	$1,500- $3,000 per kW)	$1,400- $1,700 per kW
Rated System (MW)	20	1 (High Power) 89 (High Energy)	1	1	1	0.5	1000	500
Rated Capacity (hrs)	0.25	0.25 (High Power) 4(High Energy)	7.2 max (standard discharge is 6)	1	0.67 to 2	1	8-10	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. 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 costs represented in Figure 29 are for a 1,000 MW project. CAES's O&M costs are generally within 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.

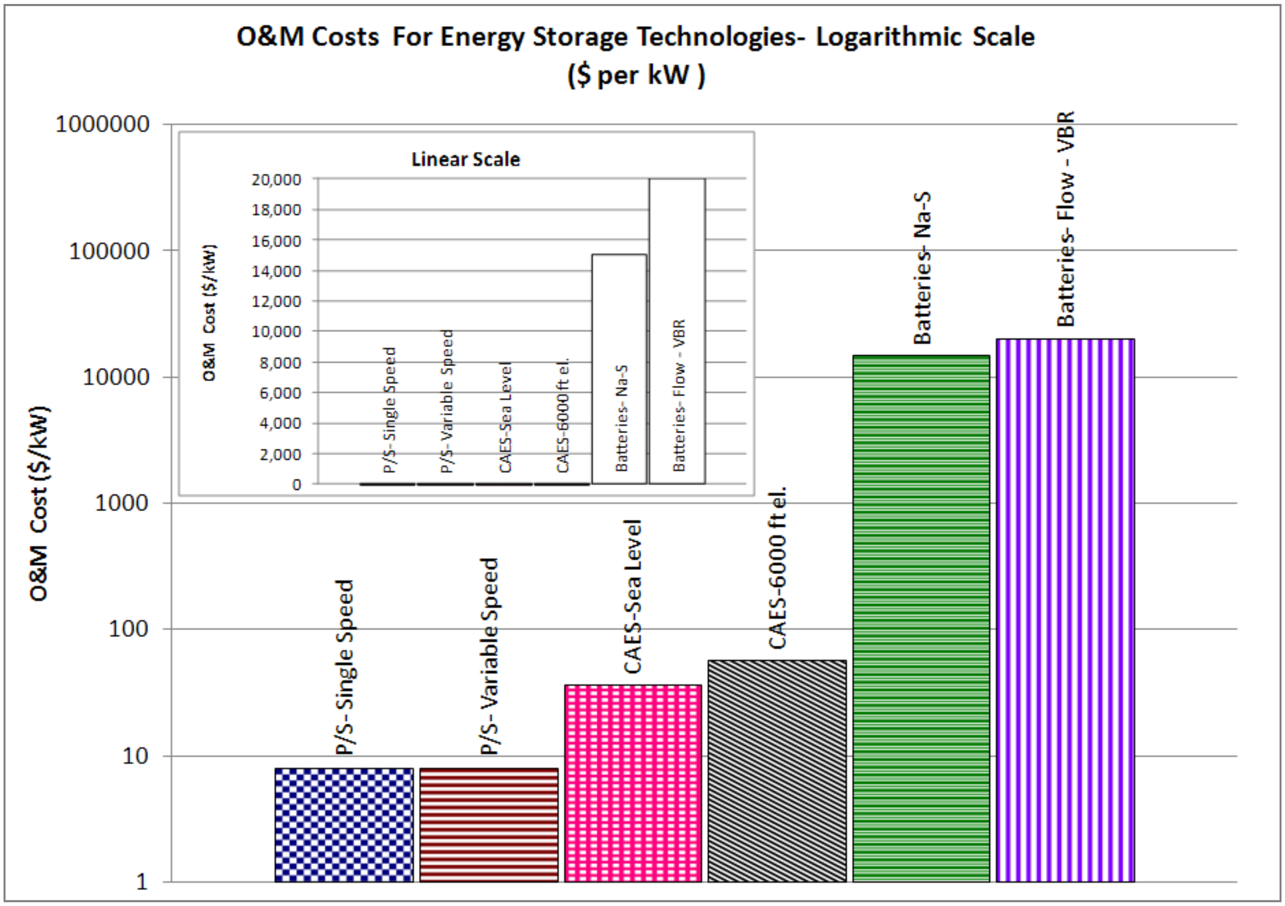

Figure 29- Operation and Maintenance Costs for Energy Storage Technologies

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, the least-cost, grid-scale storage technology is pumped storage which currently represents 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 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. Ultimately, these technologies may be suitable for bulk energy storage, but these applications appear to require more research and development. 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

APPENDIX B

Vendor Material