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National Assessment of Energy Storage for Grid Balancing and Arbitrage

Phase II

Volume 2: Cost and Performance Characterization

V Viswanathan
M Kintner-Meyer
P Balducci
C Jin

September 2013

Prepared for the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, under Contract DE-AC05-76RL01830

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Funded by the Energy Storage Systems Program of
the U.S. Department of Energy
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Pacific Northwest National Laboratory
Richland, Washington 99352

Executive Summary

This National Assessment of Energy Storage for Grid Balancing and Arbitrage is reported in two volumes, published separately by the Pacific Northwest National Laboratory (PNNL). This report represents the 2nd volume.. It discusses the cost and performance characterization of energy storage technologies used in the Assessment. It also provides details of the economic analysis discussing key exogenous input variables and the sensitivity of the overall results with respect to the exogenous input assumptions. Volume 1 presents the results of the market size analysis of energy storage for balancing and arbitrage services in 19 US regions and an analysis of the cost competitiveness of various storage technologies.

To provide the reader with the highest degree of transparency for the cost competitiveness analysis, all key cost assumptions are discussed and referenced. The authors placed great emphasis on revealing input assumptions so that the outcomes of the Assessment can be better understood. The current cost estimates are based on some 102 literature references and 12 email and telephone conversations. Furthermore, there was a need for the cost competitive analysis to capture the full cost of energy storage technology over its lifetime under the specific duty cycle for the application under consideration. While several previous reports list energy storage costs, their values are provided in isolation, without the context of application-specific storage performance, round-trip efficiency, depth of discharge, life and other relevant parameters. The cost assumptions made in the Assessment considers an estimated duty cycle for balancing services as derived in Volume 1.

Addressing key questions: This volume addressed the following set of questions in the process of determining the full characterization of cost and performance attributes of energy storage technologies:

- How does the balancing duty cycle affect energy storage system (ESS) cost? The energy to power ratio (E/P) for balancing is much lower than that for arbitrage. Hence, the application duty cycle guides ESS design and cost.
- How does ESS performance affect cost? An ESS may have a lower capital cost per unit energy, but may not be able to provide the required power, or may provide the energy at the required power at low efficiency. Response time and ramp rates are also key parameters that were addressed in this study.
- How does ESS cycle life affect cost to the end user? Some energy storage technologies such as redox flow batteries have very high cycle life, while the cycle life of other technologies is a function of depth of discharge (DOD). The cycle life relationship with respect to DOD is key to sizing the storage plant based on desired life.
- What is the cost of the PCS and balance of plant (BOP)? A range of costs applies to both the PCS and BOP. Appropriate relationships for PCS cost as a function of system voltage were used. BOP costs were obtained from a thorough literature review.
- What are the operations and maintenance (O&M) costs for the ESS? From an extensive literature review, the lower end of the O&M cost range was assigned to mature technologies, while technologies with a lower readiness level were assigned to the mid to higher end of the cost range.

Underlying assumptions for the cost analysis: The following set of underpinning assumptions were made to characterize the cost and performance of energy storage systems:

- Unit energy costs were obtained for conventional batteries, while both unit energy and unit power costs were obtained for flow batteries, pumped hydropower (PH), compressed air energy storage (CAES) and flywheels. Costs also took into account the energy to power ratio (E/P) for the storage systems.
- Separate costs for power conversion systems (PCS) were obtained for battery storage systems using appropriate relationships for PCS cost as a function of system voltage.
- Detailed cycle life analyses as a function of depth of discharge was conducted to enable storage sizing that minimizes the net present value of all costs.
- Performance parameters, such as round-trip efficiency and response time, were estimated based on available information and extensive communication with vendors.
- Balance of plant costs were estimated for all battery systems and flywheels.
- Cost estimates for the year 2020 were obtained from estimates of economies of scale and performance improvements. The technology and manufacturing readiness levels of the technologies were considered while projecting cost reductions for 2020.
- The numbers from this document were fed into an economic cost model (see Volume 1), that minimized the net present value of total costs.
- This comprehensive cost estimate across various storage technologies forms the basis for choosing the best storage option for grid balancing applications. Using appropriate modifications, this document can be used for a wide variety of applications and combinations thereof.
- We compared the cost estimates of this analysis with a recently published study by Sandia National Laboratories and Electric Power Research Institute (EPRI), the *2013 Storage Handbook*. A comparison of our results with those of the Handbook should be of value to the industry.

Summary of Cost and Performance Characterization: The following tables provide a summary of the cost and performance characteristics used in the Assessment.

Table E.1. Table Range of Capital Costs for Years 2011 and 2020.

	2011 Range		2020 Range	
Technology	$/kWh	$/kW	$/kWh	$/kW
Na-S	257-491		181-331	
Li-ion	850-1000		290-700	
Pumped Hydro	10	1500-2300	10	1640-2440
Compressed air	3	850-1140	3	500-1140
Flywheel	148	965-1590	81-148	200-820
Redox flow battery	173-257	942-1280	88-173	608-942

Table E.2. Summary of Capital and O&M Costs for Technologies Analyzed. Note values are representative for 2011 technologies. 2020 values are in parentheses.

Parameter	Na-S Battery	Li-ion Battery	Pumped Hydro	Combustion Turbine	CC	Demand Response	CAES	Flywheel	Redox Flow Battery
TRL	7	7	9	9	9	6	8	7	6
MRL	6	6	7	10	10	2	7	5	5
Battery Capital cost \$/kWh(a)	415(290)	1000 (510)	10				3	148 (115)	215 (131)
System Capital cost \$/kW			1750 (1890)	1009 (990)	Not used	620	1000 (850)	1277 (610)	1111 (775)
PCS (\$/kW)	220 (150)	220 (150)							220 (150)
BOP (\$/kW)	85 (50)	85 (50)						85 (50)	85 (50)
O&M fixed \$/kW-year	3	3	4.6	10.24	14.93		7	18	39.5 (5)
O&M fixed \$/kW-year (PCS)	2	2							2
O&M variable cents/kWh	0.7	0.7	0.4	0.9	0.4		0.3	0.1	0.1
Round-trip efficiency	0.78	0.80	0.81	0.315			0.50	0.85	0.75

(a) The battery capital cost is per unit energy, while PCS and BOP costs are per unit power.

We compared the cost estimates of this analysis with a recently published study by Sandia National Laboratories and Electric Power Research Institute (EPRI), the *2013 Storage Handbook*. A comparison of our results with those of the Handbook should be of value to the industry. Such a comparison offers a new perspective on the differences generated by our estimates based on public literature in comparison with those obtained by us and the Handbook directly from the storage vendor community. A comparison indicates that for technologies such as sodium sulfur (Na-S) and lithium ion (Li-ion) batteries, and CAES, unit energy cost was similar in both assessments, while for flywheels, pumped hydro (PH) and redox flow batteries, unit energy costs were significantly different. PCS costs estimated by PNNL were higher by more than a factor of two compared to those in the Handbook. These differences are mainly attributed to the Handbook providing costs for a specific storage system size.

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We are particularly thankful to Dr. Imre Gyuk, manager of the Energy Storage System Program of the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability for providing the funding for this project.

We would like to thank Dr. Daiwon Choi from PNNL for several useful discussions on Li-ion battery materials development. Drs. Gary Yang and Liyu Li, staff of Uni Energy Technologies, LLC, who provided significant information on battery performance trends. Special thanks and appreciation to Dr. Soowhan Kim, former PNNL staff, now with OCI Company Ltd. Korea, for providing valuable insights into the performance of vanadium redox flow storage systems.

We would also like to thank Dr. Lawrence Thaller, Consultant, for helping with developing a cost model for redox flow batteries.

Acronyms and Abbreviations

AEO	Annual Energy Outlook
ANL	Argonne National Laboratory
BASF	Badische Anilin- und Soda-Fabrik, Ludwigshafen, Germany
BOP	balance of plant
Btu	British Thermal Unit
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CT	combustion turbine
CAES	compressed air energy storage
DOD	depth of discharge
DR	demand response
E/P	energy/rated power
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESPC	Energy Storage and Power Corporation
ESS	Energy Storage Systems
EV	Electric Vehicle
GW	gigawatt
GWh	gigawatt-hours
KEMA	Keuring Electrotechnisch Materieel Arnhem
kW	kilowatt
kWh	kilowatt-hour
LCC	life-cycle cost
LHV	lower heating value
Li-ion	lithium-ion
LTC	Lithium Technology Corp
MRL	manufacturing readiness level
MW	megawatt
MWh	megawatt-hour
MISO	Midwest Independent Transmission System Operator
Na-S	sodium sulfur
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	operations and maintenance
P/E	power to energy

PCS	power conversion system
PH	pumped hydroelectric
PHES	pumped hydro energy storage
PHEV	plug-in hybrid electric vehicles
PNNL	Pacific Northwest National Laboratory
redox	reduction-oxidation
TRL	technology readiness level
TEPPC	Transmission Expansion Planning and Policy Committee
TSI	Tribology Systems Inc.
USABC	US Advanced Battery Consortium
UPS	Uninterruptible Power Supply
V2G	vehicle-to-grid
V_2O_5	vanadium oxide
WECC	Western Electricity Coordinating Council

Contents

Figures

Tables

1.0 Introduction

There have been several previous studies focusing on energy storage system (ESS) costs for transport and stationary applications. While these studies are certainly useful, the cost figures they provide use a high-level analysis based on assumptions that are largely unexplained to the reader. Some studies provide unit costs in \$/kW, while most provide costs in \$/kWh, without providing information on the energy to power (E/P) ratio. For example, a battery with a high energy to power ratio would have a lower unit energy cost and a higher unit power costs than one with a low E/P ratio.

To determine the levelized or life-cycle costs for an ESS, parameters such as round-trip efficiency, calendar life and cycle life as a function of depth of discharge (DOD) must be considered in addition to capital cost. Round-trip efficiency estimates in the literature typically do not include the associated rates of charge or discharge at which these numbers are provided. This study uses actual discharge and charge rates to estimate round-trip efficiency. It also uses one-way efficiency during discharge to estimate the actual delivered energy at various DODs. The cycle life for each technology was estimated as a function of DOD using available data from the literature. This allows calculation of actual system costs for various DODs, which is critical to obtaining a fair comparison across various technologies.

Where a large range of costs was reported, an explanation for this range was provided. Cost information was obtained from extensive interviews with several vendors for each technology. Performance curves for different technologies were studied to ensure applicability to the frequency regulation balancing application considered in this study. Performance characteristics such as ramp rates, response times, and round-trip efficiencies at various rates were obtained from interviews and literature search. For sodium sulfur (NA-S) batteries, availability of batteries with E/P ratio of one was assumed in order to minimize energy related costs. For flywheels, different storage material choices were evaluated to determine their influence on the range of unit energy cost values estimated. For redox flow batteries, our Assessment was performed using extensive optimization of the stack at high power levels, using actual performance curves generated at PNNL.

The unit energy cost for an ESS can vary widely, depending on cell design, battery module design, E/P ratio specific to the storage technology, and the needed E/P ratio for the application. For well-established technologies, materials development may not lead to much improvement in performance or lower cost. However, there appears to be ample opportunity for cost reduction and performance improvement with improved materials and better cell design with technologies at lower readiness levels. For storage systems such as redox flow batteries and flywheels, where the power and energy components are decoupled, there is significant room for optimizing both the power and energy costs independently.

Cost projections for the year 2020 will also be a function of demand for storage and the market penetration for each technology shows the installed capacity for various energy storage devices in the U.S. and worldwide (Nourai 2009). Table 1.1 indicates that there is significant room for growth for battery energy storage both in the US and worldwide. As a consequence of the scale-up in manufacturing of storage system capacities, we assumed cost reductions for the 2020 time period.

This study has developed a transparent approach to better quantify all these parameters in our effort to estimate future capital costs for the technologies considered. A detailed analysis of each energy storage technology was undertaken. It includes sizing methodology, detailed capital cost information, methodology to estimate PCS costs, fixed and variable O&M costs, performance characteristics such as round-trip efficiency and response time, technology readiness level (TRL) and manufacturing readiness level (MRL). This chapter also describes the methodology to estimate costs for 2020 based on estimated economies of scale and performance improvements.

Table 1.1. Installed Capacity for Various Energy Storage Devices in the U.S. and Worldwide

	U.S. (MW)	Global (MW)
Pumped Hydro	23,000	110,000
Compressed Air	110	477
Batteries	40	300
Other	5	10

2.0 Technology Choices for Balancing Services

This chapter provides an overview of various energy storage technologies considered in this work. The performance characteristics such as round-trip efficiency and response time are addressed, while estimates for unit power and energy costs are provided based on a combination of extensive literature review, input from vendors, and internal assessments and judgment. For conventional batteries, only unit energy costs are provided, with PCS costs provided separately for all battery types, while for redox flow batteries, compressed air energy storage (CAES), PH and flywheels, unit power and energy costs are provided separately.

2.1 Combustion Turbine

Combustion turbines (CT) provide fast response power to the grid by converting the stored energy of fossil fuels into electricity. They are typically used as the benchmark against which other ESSs are judged. As applied in this study, CTs are designed to provide an output of about 160 MW while operating at an energy efficiency of 31.5 percent. The efficiency is expressed in terms of a heat rate of 10,833 British Thermal Units per kilowatt-hour (Btu/kWh) under full load conditions. The heat rate typically increases under partial load conditions (DOE/EIA 2008). Projected to the year 2019, CT capital costs are estimated in the *2011 Annual Energy Outlook (AEO)* at $990 per kW (DOE/EIA 2011). The economic life of a CT is estimated to be 15 years.

2.2 Combined Cycle Plant

Although the combined cycle plant is not considered strictly as an energy storage technology for providing grid balancing services, it provides the electric energy supplied to other ESSs. Thus, it is the energy provider on the margin that makes up for the energy losses in the storage device. The cost for fuel, O&M, and emissions associated with the energy lost in storage are considered in the life-cycle cost (LCC) analysis.

The typical size of a combined cycle power plant is about 250-300 MW. The design heat rate is commonly cited as 7,196 Btu per kWh (DOE/EIA 2008). The design efficiency of a combined cycle power plant is approximately 47 percent and, therefore, generally higher than that of a CT. More details regarding cost assumptions underlying both CT and combined cycle power plants are presented in Section 5.0, Energy Storage Technologies.

2.3 Sodium Sulfur Battery

The largest Na-S battery system tested to date is a 34-MW battery system installed in Rokkasho village in Aomori, Japan (NGK Insulators, LTD), while the corresponding number for Li-ion systems is 2 MW (KEMA 2008). A 12-MW ESS has been installed by AES Energy Storage using Li-ion batteries supplied by A123 Systems (Parker 2010). PH systems are available in the order of hundreds of MW and MWh.

The demand response time for both Na-S and Li-ion battery systems is in the order of a few milliseconds (Divya and Østergaard 2009). This allows the systems exchange power almost instantaneously, as demanded by the grid. While numbers as high as 90 percent have been used for battery efficiency, it is important to use appropriate efficiency values that correspond to power needs for various applications. It would also be reasonable to take into account battery degradation as a function of calendar and cycle life and to incorporate losses in specific power/energy, power/energy density and efficiency losses as battery state of health degrades. For this analysis, a system efficiency of 78-80 percent was used for both battery systems. This value also includes efficiency losses in the PCS.

Currently, commercially available Na-S batteries are designed to discharge over periods as long as 7 to 10 hours (Kamibayashi et al. 2002; Nourai 2007). When these batteries are used for very small durations (in the order of seconds to minutes), the batteries can provide power as high as five times the rated power; where the rated power is defined as power for a 7-hour discharge (Kamibayashi et al. 2002). In the present study, peak power delivery occurs for only 1 to 2 minutes, hence the required power rating of the battery that is needed could be as low as 1/5 of the peak power. At present, Na-S batteries are commercially available at E/P ratios in the range 6-7. For this study, it has been assumed that in the future, batteries with an E/P as low as 1 will be available to avoid over-sizing the batteries.

2.3.1 Battery Sizing Method

Battery sizing depends on DOD, which depends on the number of charge/discharge cycles the battery undergoes during its lifetime. The only Na-S battery commercially available is manufactured by NGK Insulators, Ltd. This battery has an energy content of approximately 6.8 times its rated power (i.e., it has a storage capacity of 6.8 hours at rated power) (Nourai 2007). The batteries evaluated in this study are sized for charge-discharge durations that are much shorter than 6.8 hours; e.g., 1/2 -1 hour. Na-S batteries with design storage duration of 1/2 hour do not currently exist. As a consequence, we provide a rationale for adjusting the cost of shorter duration battery storage based on battery sizes currently available.

Typically, Na-S batteries can provide five times their nominal *rated* power for up to 5 minutes (Kamibayashi et al. 2002). In our application, (as discussed in Section 2.3), peak power demand occurs for only short durations of 1-2 minutes. Hence, using the peak power (rather than the rated power) can still be considered conservative as a sizing criterion for the battery. If the required peak power and energy are 1 MW and 1 MWh, respectively, the battery size currently available and sufficient for the 1MW/1MWh requirements would be 0.2 MW/1.36 MWh. This reflects the energy/rated power (E/P) ratio of 6.8 for Na-S batteries. Hence, sizing of the battery may be determined by peak power demand.

While the sizing discussion above is appropriate for batteries currently available, we have assumed that, as energy storage applications in utilities become more diverse, Na-S will be manufactured with a range of E/P ratios. In this Assessment we assume that Na-S batteries will be available at an E/P ratio of 1, such that the peak power for 1-2 minutes is 3 times the rated power (or energy content). This allows sizing the Na-S batteries based on the energy requirement.

For Li-ion batteries, the ability of batteries to provide 1 to 2MW/MWh has been well demonstrated. Hence, the batteries were sized per the energy requirements.

2.3.2 Capital Cost

An extensive search for capital costs of the Na-S battery system was conducted. In some publications, battery ESS costs were given in terms of $/kW, while they were given as $/kWh in others. For Na-S batteries, the estimated long-term cost appears to be about $250/kWh (Schoenung and Hassenzahl 2003; Schoenung 2001; Gyuk and Eckroad 2003; Boyes; Kamibayashi et al. 2002), while PCS costs are in the range of $150 to $260/kW. The cost range of batteries is $1800 to $2000/kW (Greenberg et al.; Kamibayashi et al. 2002), and up to $3080/kW (EAC 2008). The cost for the battery system including PCS and balance of plant (BOP) is $2400 to $2500/kW (Nourai 2007; Kishinevsky 2006). While these numbers vary widely, it should be noted that the long-term costs provided in $/kWh are only projections, and are not necessarily reflective of actual costs.

Table 2.1 summarizes the literature review of current and future capital cost for Na-S battery systems. The value of $180-$250/kWh provided by various sources is a long-term estimate. The $2500/kW value correspond to installed cost in the year 2006 for the Long Island Bus Project (Kishinevsky 2006), while the $3000/kW provided by Nourai[1] was the actual installed cost for the year 2009 for a 7MW/48MWh battery system. The latter value was used for current price of a Na-S system. The cost of the battery portion was estimated by subtracting $220/kW for PCS and $85/kW for BOP (Table 2.8), to yield $2700/kW. Using a factor of 6-6.8 for E/P_{rated} for Na-S batteries, the unit energy cost for the battery works out to be $390-$440/kWh. Since the energy/power ratio varies for the different scenarios addressed in this report, the batteries have been estimated using $/kWh numbers. For long-term cost, $250/kWh was used for the battery, along with $150/kW for PCS and $85/kW for BOP (Table 2.8).

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[1] Nourai A. 2010. E-mail message from Ali Nourai (American Electric Power) to V.V. Viswanathan (PNNL), "Na-S Battery System Cost," February 2, 2010.

Table 2.1. Summary of Current Capital Cost Diversity for Na-S Systems.

\$/kWh current	\$/kW current	\$/kWh future	Notes	Source
		180-250	Battery	(Boyes 2010; Kamibayashi et al. 2002; Schoenung and Hassenzahl 2003; Gyuk and Eckroad 2003; Schoenung 2001)
		818	System	(Gyuk and Eckroad 2003)
	1800		Battery	(Greenberg et al.)
	3080		Battery	(EAC 2008)
	2400-2500		System	(Nourai 2007[(a)]; Kishinevsky 2006[(b)])
	3000		System	(Nourai 2010)[1]

(a) More reliable 2007 numbers.
(b) Reliable – 2006 Long Island Bus actual installation numbers.

The life cycle relationship with DOD of Na-S batteries is depicted in Figure 2.1. Therefore, in the battery sizing model, we put one variable called sizing factor to size up or size down the battery energy capacity, thus determining cycle life. It is also assumed that the calendar life of the batteries is 15 years.

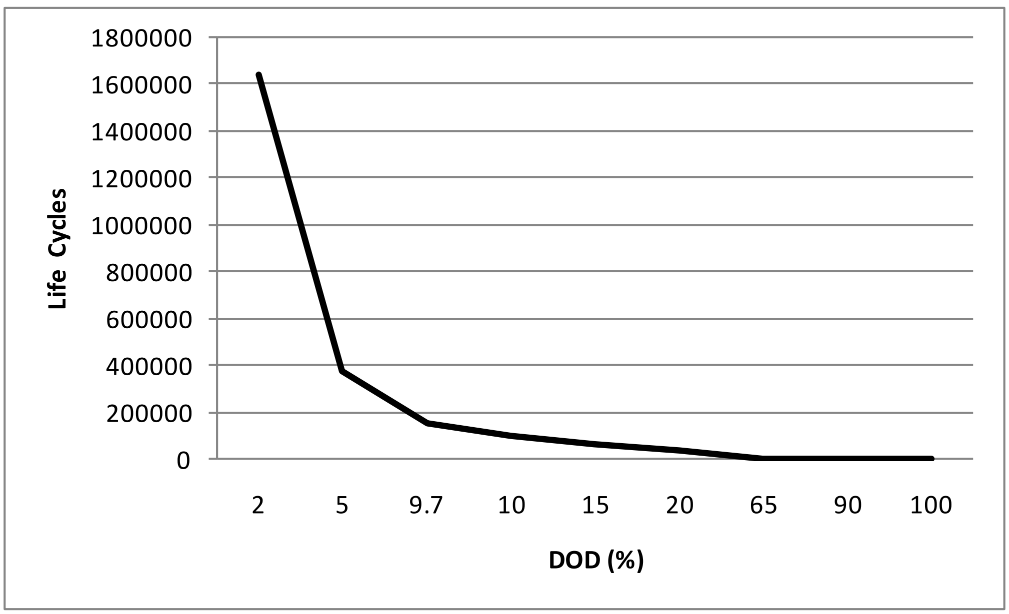

Figure 2.1. Na-S Life Cycles versus DOD Curve.

2.3.3 Fixed O&M Cost

For Na-S batteries, fixed O&M costs given in the literature varied over a wide range without any consistency regarding which cost components are included or excluded. The low end of the range starts at \$0.5/kW-year (Lamont 2004; Gyuk and Eckroad 2004) and goes up to \$51/kW-year (Schoenung and Hassenzahl 2003; Gyuk and Eckroad 2003). The latter includes insurance and property taxes. For the purpose of this study, since Na-S is a mature technology, we used \$3/kW-year as the fixed O&M cost.

2.3.4 Variable O&M Cost

Variable costs have traditionally been reported in cents/kWh, and ranged from 0.4-0.7 cents/kWh, where kWh is the cumulative energy out of the battery (Lamont 2004; Schoenung et al. 1996). The variable O&M cost for Na-S systems for various applications ranged from $2.6-$13.4/kW-year (Gyuk and Eckroad 2003). An average of these values yields $7/kW-year, while conversion of this to $/kWh yields 0.4-0.8 cents/kWh. We used 0.7 cents per kWh in this study. Table 2.2 summarizes the O&M cost estimates as found in the literature.

Table 2.2. Summary of O&M Fixed and Variable Costs for Na-S Battery.

Fixed O&M ($/kW-year)	Variable O&M	Reference
3	16.9 ($/kW-year)	(Gyuk and Eckroad 2004)
20		(Schoenung and Hassenzahl 2003)
13-51 ($2/kW-year for PCS)	2.6-13.4 ($/kW-year)	(Gyuk and Eckroad 2003)
0.5	0.7 cents/kWh	(Lamont 2004)
1.5	0.5 cents/kWh	(Schoenung et al. 1996)
3	0.7 cents/kWh	Selected for study

2.3.5 Efficiency

For Na-S batteries, the AC-AC round-trip efficiency was in the range of 0.75-0.85 (Kishinevsky 2006; Schoenung and Hassenzahl 2003; Schoenung 2001; Technology Insights 2005). We chose an average round-trip efficiency of 0.78. For the Li-ion batteries, the round-trip efficiency was estimated to be 0.8 (Rastler et al. 2007). These figures correspond to battery system efficiencies that include all of the losses in the PCS. The specific PCS round-trip efficiency was estimated to be 0.95. The round-trip efficiency is expected to change as a function of charge and discharge rate. For this analysis, the efficiency is kept constant for all rates.

2.4 Lithium-ion Battery

Li-ion batteries are available from various sources. A 2-MW battery system from AES Energy Storage, with the battery supplied by Altairnano, was tested under the direction of KEMA recently (KEMA 2008; Altair Nanotechnologies 2008). During the test, a battery management system monitored battery cell temperatures, balanced cell voltage, and kept track of battery state of charge. Three single-phase Parker Hannifin SSD power inverters were coupled to isolation transformers and fed into a step-up transformer, with the battery side running at 480 V and the grid side at 13.8 kV. These voltage values are important, since the capital cost of PCS depends on the minimum voltage at the battery side, as will be discussed later. These batteries performed well and dispatched power almost instantaneously. It remains to be seen how they will hold up over the long-term, and what the impact would be of connecting several batteries in series/parallel configuration to provide the required output voltage and power. Because of the absence of system specific information, the fixed and variable O&M costs for Na-S batteries were also used for Li-ion batteries in this study.

2.4.1 Battery Sizing

Li-ion batteries in various applications also have various P/E ratios, ranging from 60 for hybrid electric vehicles (HEVs) to 4-16 for PHEV batteries (Rousseau 2007). In the transportation sector, P is defined as the power delivered by the battery for 2 seconds. For our application, the minimum resolution is 1 minute. Typically, Li-ion batteries can be discharged continuously at the maximum rate of 2C for ~20 minutes, with a P/E ratio of 1.3, where C is the nominal energy capacity of the battery in Wh. For a 1-2 minute duration, it can be assumed that the P/E for Li-ion batteries is approximately 2. This value will vary with the battery design, with higher power batteries having larger P/E ratios. Hence, in order to determine the actual cost of a battery, it must be determined whether power or energy is limiting. It is important to consider not just the maximum power requirements, but how long this maximum power will be needed continuously. This will fix the smallest battery energy content that meets the power requirement after taking into account battery degradation.

2.4.2 Capital Costs

Present day Li-ion battery costs range from $1,015-$1,450 /kWh (Divya and Østergaard 2009) and $1000/kWh (Howell 2009). Other cost values given in $/kW are ~$1070/kW (EAC 2008) and $970/kW (Gyuk and Eckroad 2003) with the higher estimates including PCS and BOP costs. These numbers can be confusing, since the $/kW cost would equal $/kWh for a 1-hour application, while it would be twice the $/kWh value for a 2-hour application. Telephone conversations with various battery manufacturers yielded a current price of $700 to $1,500/kWh, with the price for large volume sales of 1000 batteries or more in 5 years estimated at $500-$700/kWh. Here the cost includes battery management and mark-up.[2] Cost estimation models from Argonne National Laboratory (ANL), Tiaxx and the US Advanced Battery Consortium (USABC) (Nelson et al. 2009; Barnett et al. 2009; USCAR 2007), when normalized to the same total energy, provided a cost of $440, $415, and $450/kWh, respectively, for large volume production, or an average of $420/kWh. The cost to be used for this study was assumed to be $510/kWh long-term for high volume production using the average of $600/kWh and $420/kWh. The long-term costs were $510/kWh * 2.35 = $1200/kW. Table 2.3 summarizes the cost information for Li-ion batteries.

[2] Riedel G. 2010. E-mail message from Gary Riedel (Compact Power, Inc.) to V.V. Viswanathan (PNNL), “Li-ion Battery Cost,” February 2, 2010.

Table 2.3. Summary of Current Capital Cost Diversity for Li-Ion Systems

$/kWh current	$/kW current	$/kWh high volume	Source
700-1000 Euros	--	--	(Divya and Østergaard 2009)
1000	--		(Howell 2009)
	1070 includes PCS and BOP		(EAC 2008)
	970		(Gyuk and Eckroad 2003)
1500 (60,000 cells/year)		1000-1250 (180,000 cells/year)	Lithium Technology Corp. (LTC)[3]
700			Lithium Technology Corp. (LTC) (Hazel 2010)[3]
1000-1200 (1000+ batteries/year)		500-700 (5 years from now)	Compact Power (Riedel 2010)[2]
1000			Badische Anilin- und Soda-Fabrik (BASF) (Chintawar 2010)[4]
		415	ANL (Nelson et al. 2009)
		440[(a)]	TIAX (Barnett et al. 2009)
		450	USABC (USCAR 2007)

(a) Analysis done for 5.5 kWh; number in table corresponds to a 17 kWh battery.

The life cycles versus DOD curve of Li-ion batteries are shown in Figure 2.2.

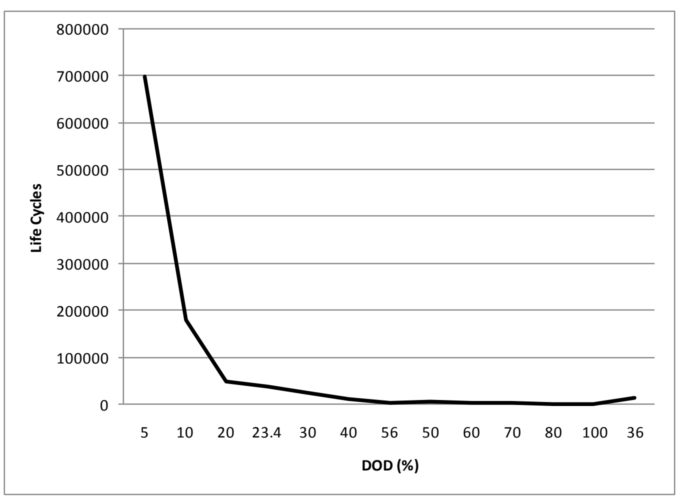

Figure 2.2. Li-Ion Battery Life-Cycle versus DOD Curve.

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[3] Hazel J. 2010. E-mail message from John Hazel (Lithium Technology Corporation) to VV Viswanathan (PNNL), "Li-ion Battery Cost," February 3, 2010.

[4] Chintawar PS. 2010. E-mail message from Prashant S. Chintawar (BASF) to V.V. Viswanathan. "Li-ion Battery Cost," February 3, 2010.

2.4.3 Efficiency

Li-Ion batteries are very efficient, with dc-dc efficiency in the 0.85-95 range (Rastler 2007) and ac-ac efficiency about 0.85 (Schoenung 2003). For this study, considering the high power of the balancing application, a dc-dc efficiency of 0.8 has been used.

2.5 Pumped Hydro Energy Storage

Of the several energy storage technologies considered, PH energy storage is technologically most mature. Table 1.1 above provided a perspective of the level of maturity based on installed capacity of grid-connected storage in the U.S. and globally (Nourai 2009).

PH energy storage technology has been used for various utility applications. One of its limitations is the need to wait prior to reversing direction from charge to discharge. Variable speed pumps/turbines allow better control of ramp rates, but cost more.

The demand response time for PH systems is fast achieving high ramp rates of 3000 MW/min, which corresponds to 3 percent rated capacity per second (First Hydro Company 2009). PH calendar life is estimated to be as high as 50 years (Schoenung 2001). There is, however, a waiting period of several minutes every time the operating mode changes. This is necessary due to significant inertia in the turbine and the hydro dynamics in and above the turbine. To meet the balancing requirements, two operating design options were investigated. The first option emulates the operation of a battery system that permits rapid changes between charging and discharging modes in accordance with balancing requirements. Advancements in the turbine/pump design allows for frequent mode change between pumping (charging) and generating (discharging) modes. However, because of the significant hydrodynamic and mechanical inertia in the turbine, a delay of significant duration is required between charge and discharge modes. After several consultations with turbine and PH storage system experts, we assume a delay of four minutes to switch operating modes in each direction (pumping to generation and vice versa).

For meeting grid balancing requirements, the estimated 4-minute delay is a significance design issue, creating the need for a back-up resource of considerable size. During cycling delay, the PH machinery is temporarily unavailable to exchange energy with the grid. Thus, some additional resources must be assigned during this period as a ‘back-up’ resource. In this Assessment, a Na-S battery was chosen as the back-up resource.

The alternative and more commonly observed operation of PH storage is a 2-mode operating schedule, whereby the machine is operated in a pumping mode during the off-peak hours and in a generating mode when demand is higher. While operating in either of the modes, the machine can be used to meet grid balancing requirements. However, the pump/generator size must be upsized compared to ‘multiple mode changes’ mode because the balancing requirements must be met in both pumping and generating modes independently. This requires a pump/generator size that covers the entire swing range from full increment to full decrement. A very small Na-S battery may be applied as a back-up resource to meet the balancing requirements during the 2-mode change.

2.5.1 Capital and O&M Costs

For PH systems, the capital cost is generally provided in $/kW. Most systems provide this information including PCS and BOP costs. For this analysis, BOP costs for PH will be neglected, since the values provided in the literature are as small as $4/kWh. Additional capital cost information was provided by Rick Miller of Renewable Energy Services in several e-mail communications.[5,6] The capital costs for single speed PH systems are in the range of $1,500 to $2,500/kW, while the range for variable speed pumps is $1,800 to $3,200/kW. This cost is broken down into three parts:

1. Pump/turbine and motor/generator costs, ($600/kW for single speed and $850/kW for variable speed units).
2. Hydro-mechanical equipment, transformers, switchgears, remaining BOP.
3. Engineering/design services, civil construction, excavations and construction for water conveyance system, upper and lower dams and reservoirs.

PH pump and turbine costs typically vary significantly, and have been reported to be as low as $78/kW to $264/kW (GE Energy 2004; Alstom 2009). Since these costs are about 33 percent of total system cost, they also contribute a large variation in system cost, in addition to the siting-related contribution.

A range of values obtained from the literature on capital costs, O&M fixed and O&M variable for PH systems is shown in Table 2.4. While replacement costs are minimal, generators need rewinding every 20-25 years. PH round-trip efficiency is 80 to 82 percent, and does not include transmission losses. It should be noted that the reported 75 percent efficiency probably includes transmission losses.

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[5] Miller R. 2010. E-mail messages from Rick Miller (Renewable Energy Services to V.V. Viswanathan (PNNL), "Pumped Hydro Cost and Performance," January 26, 29, February 1, and 22, 2010.

[6] Miller H. 2011. E-mail message from Harry Miller to Vilayanur Viswanathan, "Attention Harry Miller," October 4, 2011.

Table 2.4. Capital Costs for PH Systems.

$/kW	O&M Fixed $/kW-year	O&M Variable cents/kWh	Efficiency AC-AC	Reference
1000	2.5	Very small	0.75	(Schoenung and Hassenzahl 2003)
600	3.8	0.38	0.87	(Schoenung 2001)
1483				(Geadah 2009)
1552				(Geadah 2009)[a]
> 350 €/kW			0.70-0.80	(Fodstad)
		2	0.75	(Rahman 1990)
			0.75	(First Hydro Company 2009; Jenkinson 2005)[b]
1500			0.82	(NHC 2007)[c]
1000				(Boyes 2010)
1800-3200[d]			0.78-0.82	(Miller 2010)[5]
517, 583[e]	4.6		0.80[f]	(Figueiredo et al. 2006)
1100-2000[g]	4.3	0.43[h]	0.60-0.78	(Lipman et al. 2005)
1700[i]				(Miller 2010)[5]

(a) 2016-2020 costs.
(b) At Dinorwig (1800 MW 1.5 min start-up).
(c) 500 MW fully dispatchable in 15 seconds with unit spinning, 10 min black start.
(d) $1500-$2500/kW for single speed.
(e) $517/kW Grand Cache 218 MW, $583/kW Kneehills 194 MW.
(f) Efficiency set at 0.8, not measured.
(g) Projected cost for year 2020 was $800/kW.
(h) Referenced Schoenung et al. (1996).
(i) $245/kW for pump turbine, motor generator and power electronics.

2.5.2 Performance Parameters

PH energy storage technology has been used for various utility applications. As noted above, one of its principal limitations is the need to wait prior to reversing direction from charge to discharge. Variable speed pumps/turbines allow better control of ramp rates, but cost more.

The response time for PH systems is fast achieving high ramp rates of 3000 MW/min, which corresponds to 3 percent rated capacity per second (First Hydro Company 2009); calendar life is estimated to be 50 years (Schoenung 2001).

Figure 2.3 shows typical start and stop times for PH systems. It takes about 12 seconds for the system to go from a spinning to generation state, while the corresponding time for transition to pumping is 30 seconds. The average time from shutdown to generation is 90 seconds, while shutting down the system from the pumping state takes about six minutes.

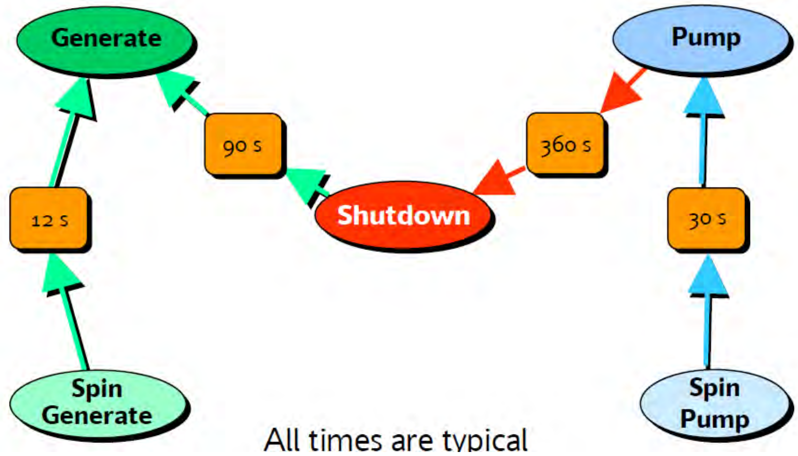

Figure 2.3. Typical Duration Between Various Modes at the Dinorwig PH System (Jenkinson 2005).

2.6 Compressed Air Energy Storage

Compressed air energy storage uses electricity to compress air using an electric motor-driven compressor and store it either in underground caverns or in above-ground vessels or pipes (Rastler 2011a; Cavallo 2007). Underground storage comprises various geologic formations such as salt caverns, rock mines, depleted oil and gas reservoirs and aquifers, and is suitable for hundreds of MW of storage for several hours (Ridge 2005). Generation of electricity is enabled by expansion of the compressed air through one or more turbine-alternators. Conventional or diabatic CAES burns natural gas in a CT to generate electric power. The exhaust from the CT is used to preheat the compressed air, which is expanded through a turbine with high pressure and low pressure stages (Drury et al. 2011). In a variation of this, the compressed air is heated with natural gas. There are variations on the CAES concept that include thermal energy storage, operation in the adiabatic mode or isothermal mode with elimination of the CT, or direct coupling of the compressor with wind turbines to avoid conversion of mechanical energy from the turbines to electricity (Grazzini and Milazzo 2008). The overall efficiency for diabatic CAES is ~0.5, while it is anticipated that efficiency as high as 0.7 can be obtained for adiabatic/isothermal CAES (Drury et al. 2011). One of its limitations is the need to wait for a few minutes prior to reversing direction from charge to discharge or vice versa. Ramp rates in the range of 15-40 percent of rated power per minute have been obtained.

2.6.1 Current Status

There are two operating CAES plants in the world, a 300-MW/3-h plant in Huntorf, Germany, commissioned in 1978 and a 110-MW/26-h plant located in McIntosh, Alabama, which was commissioned in 1991. The Huntorf plant, designed by ABB, has a rated output of 290 MW over 3 hours (Succar and Williams 2008) with an overall efficiency of 42 percent and a heat rate of 5870 kJ/kWh lower heating value (LHV). The McIntosh plant, designed by Dresser-Rand, recuperates the turbine exhaust heat, thus improving the overall efficiency to 53 percent, with a heat rate of 4330 kJ/kWh LHV (Succar and Williams 2008; BINE 2007). Dresser-Rand supplied all the rotating equipment for this plant, while Energy Storage and Power (ESPC) was responsible for engineering, design, manufacture, testing and commissioning of the plant (Lucas and Miller 2010; Nakhamkin et al. 2010). Other proposed projects include the limestone mine in Norton Ohio (800 MW) and plans by Ridge Energy Storage & Grid

Services L.P. for several CAES installations in Texas, as described by Succar and Williams (2008). These plants are termed first generation, with compressed air being heated by a high pressure and low pressure combustor, and the heated air passing through a high and low pressure expander. In the second generation CAES plant developed by ESPC, one-third of the rated power is generated by a CT which heats atmospheric pressure air. The exhaust from the CT is used to heat the stored compressed air, which is passed through an expander to generate power. Separate power trains are used for the compression and expansion sections in order to improve reliability at the expense of higher cost (Nakhamkin et al. 2010).

2.6.2 CAES Capital and O&M Cost

For CAES systems, capital costs are typically provided in $/kW. For most systems, the BOP and PCS costs are also included. Some of the main suppliers of CTs are GE, Siemens and Westinghouse, while compressors are supplied by MAN Turbo, Dresser-Rand, Mitsubishi Hitachi, Rolls-Royce and Ingersoll Rand (Nakhamkin 2008). The cost for the current generation 110 MW CAES plant was estimated to be $1250/kW, with second generation systems estimated to be $750/kW. Systems based on advanced concepts were estimated to be in the $500-$560/kW range (Daniel 2008; Nakhamkin et al. 2010). The capital cost was quoted at $1200/kW for the recently cancelled Iowa project.[7]

Table 2.5 summarizes CAES capital costs from the literature. The power-related capital costs for CAES lie in the range $500-$1750/kW, while the energy related costs are approximately $3/kWh for salt dome storage. The energy related costs varies with storage type, with porous rock storage and surface storage costs higher by more than an order of magnitude. For this work, the capital cost was assumed to be $1000/kW in 2011 and $850/kW in 2020, taking into account an increase in motor/generator material cost that is expected to counter some of the advances anticipated, with energy related costs assumed to be $3/kWh.

[7] Cavallo A. 2011. E-mail to Vilayanur Viswanathan, received September 16, 2011.

Table 2.5. Summary of Capital Cost Diversity for CAES Systems

Capital Cost ($/kW)	Capital Cost ($/kWh)	O&M Fixed ($/kW-year)	O&M Variable (cents/kWh)	Ramp Rate % Rated Power/min	Reference
560	3	1.2	0.15		(Cavallo 1995)
425	3	2.5			(Schoenung and Hassenzahl 2003)
440[(a)]	1	13	0.2	10-25 [(b)]	(Gyuk 2003)
430	40[(c)]	19-24.6		10-25 [(b)]	(Gyuk 2003)
500-850			0.3		(van der Linden 2006, Miller 2011[6])
350	1/0.1/30/30[(d)]	6			(Herman 2003)
350	1.75/40[(e)]				(Eckroad 2004)
1700 (72 MW adiabatic CAES)		6			(Nakhamkin et al. 2007)
800-850				27	(Nakhamkin et al. 2009)
				18	(Ridge Energy 2005)
890					(Greenblatt 2005)
750-800		<5[(f)]			(Nakhamkin 2008)
580	1.7			7-14	(Succar and Williams 2008)
960-1250	60-120				(Rastler 2010, Daniel 2008)
850-900[(g)]	85-90			12-27 [(h)]	(Nakhamkin et al. 2010)
500			0.3	20-35	(Miller 2011[6])
				40	(Schainker et al. 2010)
				10-20 [(i)]	(Lucas 2010)

(a) 200 MW AC, salt mine storage, includes BOP of $170/kW.
(b) 10%/min generation, 25%/min compression.
(c) 10 MW AC surface storage.
(d) Salt/porous/hard rock/surface.
(e) 1.75 for salt mine, 40 for surface.
(f) Replacement cost <$5/kW-year.
(g) S gen 2 plants, included energy costs for 10h storage. $/kWh obtained by dividing $/kW by 10.
(h) Load following in the 20%-100% of capacity within 3-5 minutes.
(i) 10%/min generation, 20%/min compression.

2.6.1 CAES Performance and Life

The energy and power components for CAES may be assessed separately. CAES has a start-up time of <5 minutes during compression to full load, while the corresponding start-up time in the power generation mode is <10 minutes.[6] This affects the sizing of the ESS, since a battery or other resource needs to be used during the changeover period. Additionally, if the CAES is used as a load at night and as a generator during the day, it needs to be oversized to account for continuous generation and compression.

The cycle life, while not known, is expected to be >10,000 cycles based on the 20-30 year life at the Huntorf and McIntosh plants and the 5000+ combined starts for generation and compression at the McIntosh plant (Hoffman 2008). A wide range of round-trip efficiency (48-90 percent) for CAES has been quoted in the literature using different definitions (Drury 2011; Macchi and Lozza 1987;[6] Succar and Williams 2008). The efficiency is in the 77-89 percent range if it is defined as the ratio of electricity generated to the sum of the electricity input to the compressor and the electricity that could have been generated by the natural gas in a CT; while it is approximately 66 percent for a ratio of output electricity adjusted by subtracting the electricity that could have been generated by the natural gas in a CT to the electricity input to the compressor (Succar and Williams 2008). In this work, efficiency is defined as the ratio of electricity generated to total energy input to the system, and is 50 percent. It is anticipated that efficiency as high as 0.7 can be obtained for adiabatic/isothermal CAES (Drury et al. 2011), but the technology is not yet mature. A summary of novel concepts for the next generation CAES plants was described by Nakhamkin et al. (2009).

The ramp rates for CAES were reported in the range of 17-40 percent rated power/minute (Gyuk and Eckroad 2003; Ridge 2005; Succar and Williams 2008; Nakhamkin et al. 2010[6]). A ramp rate of 30 percent of rated power per minute has been assumed in this work.

2.7 Flywheels

Flywheels consist of rotors made of steel or carbon composites and store energy in the form of kinetic energy proportional to the rotor's mass and the square of its angular velocity. The motor/generator set is coupled to the same shaft to which the rotors are attached, with rotation occurring in vacuum to minimize losses. The rotors can be supported by passive or electro-magnetic bearings, with high temperature superconducting magnetic bearings requiring cryogenic cooling providing the best performance (Bolund 2007). While rotors made of graphite fiber composites are currently used, carbon nanotubes are expected to increase the energy density by an order of magnitude over carbon fiber winding (Sibley 2011a). The efficiency of the flywheel systems ranges from 85-90 percent, while their ramp rate is as high as 100 percent of rated power per minute.

2.7.1 Current Status

The major manufacturers of flywheels include Beacon Power, Tribology Systems Inc. (TSI), Velkess Flywheels and Amber Kinetics, with about half the manufacturers using steel rotors, which is appropriate for low energy power quality applications (Gyuk 2003). Among the current manufacturers, Beacon Power has developed flywheels that can provide 25 kWh at a power of 100 kW, and is currently developing 100 kW/100 kWh modules.[8] Flywheel systems using such modular flywheels have been developed to provide 20 MW power and energy of 5 MWh, with a goal of assembling systems with100-MWh capacities. In terms of losses, based on testing of 100-kW modules on the grids of independent system operators in California and New York (CAISO and NYISO, respectively), total losses were 7.09 percent per year, with 7 percent corresponding to efficiency losses, and 0.09 percent to standby losses. For their 100-kW/25-kWh module, all of the energy is usable, because its design storage capacity is oversized to 40 kWh. The flywheel uses a permanent magnet high speed motor. For this module, the system round-trip efficiency was 85 percent, with 13 percent losses attributed to the PCS8. The 40-kWh systems running at 25-kW peak power and 4-kW continuous power developed by Tribology Systems Inc., have ceramic bearings, with an estimated energy loss of <0.03 percent per hour, allowing the flywheels to operate

[8] Lazarewicz M. 2011. Telephone conversation of Viswanathan with M Lazarewicz on September 12, 2011.

unpowered for over 4 months (Sibley 2011a[9]). Velkess has developed 10-kW/80-kWh systems targeting telecommunication applications (Gray 2009). Amber Kinetics has a demonstration scheduled in 2013 on the CAISO grid, with initial development of a 20-kW, 5-kWh system in Phase 1, followed by the targets of a 500-kW, 125-kWh commercial-scale prototype system, and a grid-connected demonstration system at the MWh level (Chiao 2011). Active Power and VYCON Energy are targeting UPS markets. Active Power has deployed over 2000 flywheels for UPS with a diesel generator to deliver 15-seconds ride through at peak power and 30 seconds at 50 percent of peak power (Active Power 2011). While the cost per kW was stated to be $330/kW, this low cost could possibly be due to the small duration for which these systems are designed. As of now, Active Power is not participating in the regulation market. VYCON Energy has developed 300 kW, 1.1 kWh flywheel systems targeting the uninterruptible power system (UPS) market.[10] Other markets currently being targeted are capturing regenerative power from cranes, electric rail, and buses. The UPS market has low cycle life requirements, while in cranes, flywheels cycle every 2 minutes for 8 hours. For the latter application, flywheels are de-rated both in terms of power and energy. Their systems have standby losses of 2 kW, and the efficiency during continuous operation is anticipated to be about 97 percent.

2.7.2 Flywheels Capital and O&M Costs

Beacon Power signed a $2-million contract with the New York State Energy Research & Development Authority (NYSERDA) for partial funding of its 20-MW/5-MWh frequency regulation plant in Stephentown, New York (Beacon 2010). The plant is expected to consist of 200 Smart Energy 25 flywheels (100 kW, 25 kWh), with a total estimated cost of $25 million, out of which $5 million was estimated to be installation cost (Lazarewicz 2011). This corresponds to $1,000/kW for the system excluding installation costs. The flywheel is a turnkey system, with a dc-dc converter stepping the voltage to 480V dc, followed by a bi-directional inverter and a transformer for conversion to 115 kV ac. This was a significant increase from the estimated $10-$12 million reported earlier (Rounds and Peek 2008). The estimated cost for a 250-kWh TSI flywheels system was $200/kWh, and was $165/kWh for a 1 MWh system, with the cost inclusive of the motor/generator cost for charging and discharging the flywheel. These estimates were based on current carbon fiber prices, and are mainly sensitive to the energy content of the system because of the >1-h charge-discharge periods [11]Velkess Flywheels have a flexible rotor and a passive magnet, with a lower associated construction cost. For MW/MWh sized system, the costs were estimated to be $200/kW and $100/kWh.[12] Table 2.6. shows a list of these costs. The capital cost in terms of $/kWh for steel, graphite and carbon fiber rotors are also listed. Amber Kinetics uses commercially off-the-shelf bearings and low cost high strength steel rotors, with a goal to reduce the unit energy cost for the rotors by a factor of 15 (Chiao 2011).

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[9] Sibley L. 2011b. Telephone conversation with Lew Sibley, of Tribology Systems, Inc. on September 26, 2011.

[10] Ulibas O. Telephone conversation with Vilayanur Viswanathan of PNNL, December 22, 2011.

[11] Sibley L. 2011c. E-mail received from Lew Sibley of Tribology Systems, Inc. on October 27, 2011.

[12] Gray B. 2011. Telephone conversation with Bill Gray of Velkess, Inc. on September 27, 2011.

The O&M costs are in the $20-$30/kW-year range (Walwalkar et al. 2006), $18/kW-year (Gyuk and Eckroad 2003) and 2 percent of capital costs per year or $7/kW-year for high power low energy systems (Taylor 1999), while O&M variable cost was 0.1 cents/kWh (Gyuk and Eckroad 2003). For this study, fixed O&M costs of $18/kW-year and variable O&M costs of 0.1 cents/kWh were used.

Table 2.6. Summary of Capital Cost Diversity for Flywheel systems.

Capital Cost ($/kW)	Capital Cost ($/kWh)	O&M Fixed ($/kW-year)	O&M Variable (cents/kWh)	Efficiency (%)	Reference
200-500 (5s)		2% of capital costs			(Taylor et al. 1999)
800 (UPS)					(Taylor et al. 1999)
200-500 (few min)					(Prodromidis and Coutelieris 2012)
1000-3000 (1h)					(Prodromidis and Coutelieris 2012)
1000 (Gen 4 Beacon)[(a)]				85%	(Lazarewicz 2011)
		18	0.1		(Gyuk 2003)
1630					(Rounds and Peek 2008)
	22[(b)]				(Liu and Jiang 2007, Bolund 2007)
	38[(c)]				(Liu and Jiang 2007)
	104-290[(d)]				(Bolund 2007)
	165-250[(e)]			95%-97%[(f)]	(Sibley 2011b,c) [9,11]
200[(g)]	100			90%-95%[(h)]	(Gray 2011)[12]
650 (1MW/ 0.25 MWh)		20-30			(Walwalkar et al. 2006)
				85%	(Chiao 2011)

(a) For MW/MWh high voltage system. For 48Vdc system, efficiency is 85%. May not include PCS losses Excludes installation cost of $5M for a 20 MW plant. Cost for Gen 3 was $2000/kW
(b) Steel rotor
(c) Graphite rotor
(d) $104/kWh for Toray Carbon Fiber CT1000 from Toray and $290/kWh for HexTow® AS4C carbon Fiber from Hexcel Corporation
(e) $250/kWh for a 250 kWh system and $165/kWh for MWh-sized system. Operation time > 1h
(f) May not include PCS losses
(g) Unit power ($/kW) and energy ($/kWh) costs provided separately for TSI systems
(h) For MW/MWh high voltage system. For 48Vdc system, efficiency is 85%. May not include PCS losses

2.7.3 Flywheels Performance and Life

Flywheels are expected to last 25 years, with a cycle life of 125,000 at 100 percent DOD (Lazarewicz 2011; Sibley 2011a[12]; Chiao 2011). While DOD typically determined cycle life for batteries, for flywheels, the wear and tear mainly depends on the rotational speed of the rotors. Hence, the number of charges to 100 percent state of charge (SOC) is expected to be more life-degrading than a similar number of charges to 50 percent SOC. For example, the cycle life at 25 percent DOD was estimated to be 450,000 by Beacon Power.

As discussed earlier, the efficiency of the Beacon flywheels system is 98 percent, with additional 13 percent losses from the PCS. The Tribology Systems Inc. (TSI) Flywheel has efficiency in the 95-97 percent range due to low losses associated with the ceramic bearings. The round-trip efficiency of the Velkess Flywheels kW sized systems (Gray 2009) and the Amber Kinetics systems (Chiao 2011) is 85 percent, while the efficiency for MW sized systems was estimated to be 90-95 percent) [12]. The ramp rate for the Velkess Flywheels is twice the rated power in less than a second using 250-kWh modules[12]. Most flywheels are oversized since operating at 100 percent DOD is not practical due to low efficiencies at low speeds. One unique feature of the TSI system is that over-sizing is not necessary, since the flywheel can be discharged down to low speeds without loss of efficiency.[11]

2.8 Vanadium Redox Flow Batteries

Redox flow batteries were developed in the 1970s, and have gained prominence recently due to their flexibility of use (Herman 2003; Rastler 2010). Similar to a regenerative fuel cell, the power and energy components are separated, with the stack providing power and the electrolyte storage tanks providing energy. Vanadium redox flow batteries with a power and energy capacity in the kW-MW and kWh-MWh ranges, respectively, have been deployed. The efficiency of these systems is in the 70-80 percent range with response time on the order of milliseconds. The stacks last at least 10 years and can sustain >200,000 cycles. Active research is ongoing to reduce stack costs by addressing individual components and also by increasing the power density.

2.9 Current Status

Vanadium redox flow battery systems range from several small 5-kW units deployed in field trials to much larger installations, as noted in the following examples:

- 15-kW/120-kWh system deployed by Risø-DTU in Denmark.
- 50-kW/200-kWh unit installed by Kashima-Kita Electric Power in 1995.
- 200-kW/800-kWh system installed by VRB Power Systems at the King Island wind farm in Australia.
- 250-kW/2-MWh system built by VRB Power Systems installed by PacificCorp in Castle Valley, Utah.
- 4-MW/6-MWh system built by Sumitomo Industries installed at the 32MW Tomamae wind farm in northern Japan.

(Rastler 2010; Eckroad 2007; Yang et al. 2011; Steeley 2005; Zhang 2009; Skyllas-Kazacos 2010).

While most vanadium redox flow batteries operate in the 0°C-40°C temperature range, a wider -10°C to 50°C range has been demonstrated (Li et al. 2011). Widening the temperature range would lower costs associated with heat exchangers, while also increasing the life of the electrolyte. Efforts are also ongoing to reduce stack costs by developing higher performance stacks, lower cost membranes, electrodes and bipolar plates. On the energy side, higher concentration electrolytes are being developed to increase energy density. System design issues being addressed include minimization of losses associated with pumping and shunt current.

2.9.1 Performance and Life

The efficiency of the system is mainly a function of the power density, and can be controlled to be in the 75-85 percent range by varying the stack area for a desired power output. Hence, this provides an additional lever, by designing the stacks appropriately for short duration applications such as balancing and regulation versus energy-intensive applications such as arbitrage and load leveling. The cycle life of a redox flow battery depends on its use profile. Tokuda et al. (2000) targeted at least 1500 cycles over 10 years. In principle, the battery can be cycled an order of magnitude higher, as long as the charge voltage is maintained below the gas evolution range (Vanadiumsite 2011; Energystoragenews 2010; Vfuel 2011; Staudt). The Tomomae wind energy storage demonstration using a 4-MW/6-Wh Sumitomo Electric Industries system has undergone >200,000 cycles after 3 years, thus indicating the life for vanadium redox battery systems is mainly limited by calendar life rather than cycle life (Skyllas-Kazacos 2011).

2.9.2 Capital and O&M Costs

A wide range of costs has been reported for redox flow batteries, with unit costs varying based on the power to energy ratio (Eckroad 2007; Gyuk 2003; Corey 2002). A comprehensive review of the vanadium redox flow battery systems deployment and cost analysis was recently published (Kear et al. 2011). Table 2.7 provides a summary of vanadium redox flow battery costs from the literature.

We have estimated the power and energy cost components in this work. The stack cost is mainly governed by separator costs, which currently are in the \$500-\$800/m^2 range. It is expected that in the next 10 years, the separator costs would drop to \$200/m^2 (Kannurpatti 2011). Felt electrode development with various forms of heat and chemical treatment was expected to enhance performance (Yang et al. 2011). The energy costs are mainly dependent on V_2O_5 costs, which peaked in 2005 at \$27/lb, and have stabilized since then at \$10/lb (Eckroad 2007). With recycling, V_2O_5 costs are expected to contribute less in the future. The electrolyte is expected to be very stable, thus enabling reuse in the future. For this work, a 2020 cost estimation was prepared, assuming an anticipated drop in component costs and a 20 percent anticipated increase in power density, which would decrease stack costs for a fixed power output. In addition, for both 2011 and 2020 costs, the unit power costs were divided by 1.4, which is the ratio of peak to rated power (Bindner 2010). In 2020, the capital cost used in this study was \$131/kWh for the energy related component and \$775/kW for the power-related component. Of the total power-related costs, \$496 are associated with stack costs and the economic life of the stack is assumed to be 10 years compared with 25 years on all other components. In 2011, power-related capital costs used were \$1111/kW for the entire system and \$783/kW for stack costs. The 2011 energy related component was estimated at \$215/kWh. Fixed and variable O&M costs for 2011 and 2020 were estimated at \$5/kW and 0.1 cents/kWh, respectively.

Table 2.7. Summary of Capital Cost Diversity for Vanadium Redox Flow Battery Systems.

Capital Cost ($/kW)	Capital Cost ($/kWh)	O&M Fixed ($/kW-year)	O&M Variable (cents/kWh)	Efficiency (%)	Reference
1138 (Euros)[a]	100 (Euros)				(Joerissen et al. 2004)
				72-8%	(Kaizuka and Sasaki 2001; Tokuda 2000; Rydh 1999; Zhao et al. 2006; Eckroad 2007)
4800/29600 (2.5MW-10/ 100 MWh)	1200/350 (2.5MW-10/100 MWh)	4.6[b]			(Corey et al. 2002)
1800/2600 (4/8h) (Euros)		0.5% capital cost		65-75	(Staudt)
1200/2000 (10MWac 30-100 MWh)	400-200 (10MWac 30-100 MWh)	39[c]	0.2-0.7	65-75	(Gyuk 2003b)
1620	217			72-90	(Kear 2011)
2300/1250	300/210				
970 (Euros)[d]	78 (Euros)			75	(Jossen and Sauer 2006)

(a) For 2 kW 30 kWh and 2 kW 300 kWh systems
(b) Actual O&M cost was $20/kW-year, but this may include annual property taxes and labor. For Na-S, O&M cost was $13/kW-year. Use this ratio and multiply by O&M cost for Na-S used in this report
(c) Includes annual property taxes and labor, which can be as high as 2% of capital costs
(d) For 2 kW/30 kWh system. Tank cost was included in their calculation – removed it

2.10 Demand Response

Demand response (DR) is an under-exploited resource fully capable of providing balancing services. Similar to a generator that provides balancing services, a load customer who operates up and down from an original operating point creates a balancing reserve value. In fact, PJM, a regional transmission organization, allows large load customers to participate in the regulation services markets. Small loads, such as residential and commercial customers, can also deliver these services to the grid. The challenge is how to organize a large number of small devices to operate in a coordinated fashion such that they deliver balancing value reliably at a sufficient scale. Communications technology and smart grid control strategies may advance the accessibility and, thus, the utilization of small residential and commercial end-use devices to deliver balancing value to the grid.

For the purpose of this study, plug-in hybrid EVs (PHEVs) are selected as the key candidates for this service, recognizing that other appliances may also contribute at certain times. PHEVs are not currently mass-produced, and it will take some time for PHEVs and other EVs to gain market share that will amount to a sizable load. However, significant efforts in standardizing the communication protocol to the vehicles are underway to enable smart charging strategies. This would make EVs a likely candidate for providing balancing services.

Figure 2.4 shows the balancing signal and the load resource availability of EVs. Balancing would be achieved solely during the charging mode. No Vehicle-to-Grid (V2G) is necessary for meeting the balancing requirement. PNNL has coined the term “V2Ghalf”, expressing the feature of intelligent or smart charging whereby the balancing is provided by a load resource (i.e., charging of an EV/PHEV battery) in such a manner that charging is varied around an operating point. The aggregated EV battery charging load is not constant but varies as a function of time-of-day and availability of public charging stations at the workplace which can contribute to making the vehicle resource available as a grid service. The number of vehicles necessary to provide a sufficient load resource is then the number of vehicles that will furnish just enough load to meet the maximum balancing capacity, as seen in Figure 2.4, at 6:00 a.m. when most of the chargers are turned off after having recharged batteries overnight. More specific information on how the EV resource can be deployed is found in Tuffner (2011).

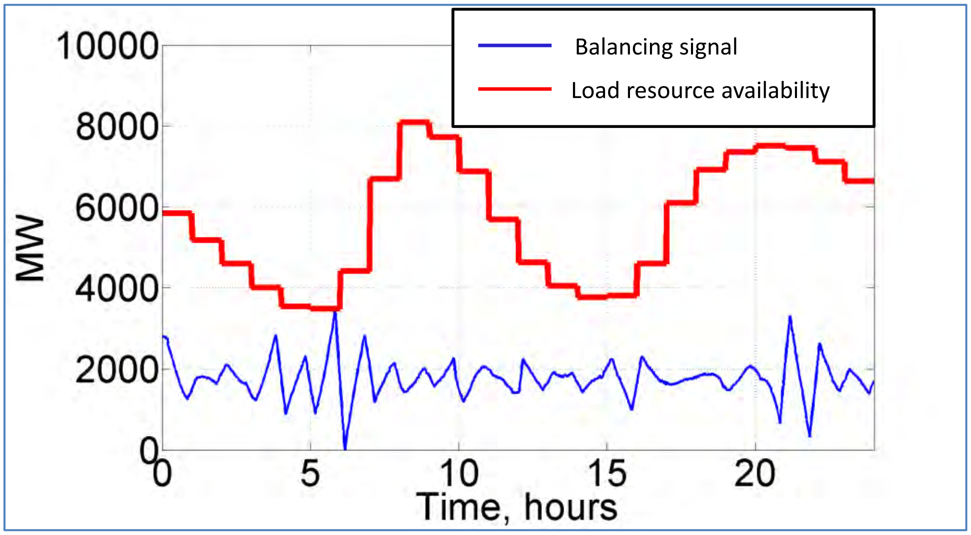


Figure 2.4. Load Curves for PHEV with Home and Work Charging and Balancing Signal for the Average PHEV

2.11 Power Conversion System

PCS converts dc power from the ESS to ac power for the grid during discharge. During charging, the inverse conversion takes place, i.e., grid ac grid power is converted to dc. The capital cost and efficiency of the PCS is a function of ESS operating parameter.

2.11.1 Capital Cost

The cost of the PCS was estimated from the $/kW values available in the literature. It should be noted that the rated power of PCS is typically specified for continuous power output. For durations of seconds to minutes, the peak power can be at least two times higher than the PCS rated, which would bring costs down.

A detailed explanation of PCS and BOP costs was provided by Gyuk and Eckroad (2003). A Type I PCS is maintained in hot standby and is operated continuously for durations greater than 30 seconds. A Type II PCS may be employed for applications allowing 10 minutes advance notice, while Type III is used for durations less than 30 seconds. Type I describes the PCS utilization mode most appropriate for this Assessment. The cost for Type I PCS as a function of output power P is given by Equation 1:

$$\frac{\$}{kW} = 300 \cdot p^{-0.3} \tag{1}$$

This provides a range of \$40-\$300/kW for applications needing 1 GW-1MW power. Clearly, as the system power increases, the cost for PCS drops. Type I PCS costs are also given by Equation 2:

$$\frac{\$}{kW} = 13500 \cdot V^{-0.59} \tag{2}$$

where V is the minimum voltage on the battery side, and ranges from 300-3000V. Since the power needs in this study are in the order of a few GWs, for a minimum voltage of 3000V, the PCS cost would be \$120/kW. For this work, we have assumed a cost of \$200/kW, where the power corresponds to half the peak power, (or \$100/kW based on peak power).

BOP costs include various components: systems integration (in \$/kW) not covered by PCS, costs for project engineering, grid connection (transformers), land, foundation, and buildings (Gyuk and Eckroad 2003). The BOP systems integration cost accounts for any underestimation of integration costs for PCS and energy storage, especially for pre-commercial systems. A value of \$100/kW was proposed for pre-commercial systems, and \$50/kW for commercial systems (Gyuk and Eckroad 2003).

Table 2.8 summarizes the literature review of current and future capital cost for PCS and BOP. For the year 2011, PCS cost of \$220/kW was used, while for the year 2020, a cost of \$150/kW was used in this study. BOP cost of \$85/kW was used in this study. The costs for 2011 and 2020 were kept the same, since this is a catch-all for any unassigned cost.

Table 2.8. Summary of Current Capital Cost Diversity for PCS and BOP

$/kWh current	$/kW current	$/kWh future	Notes	Source
	150-240		PCS	(Schoenung and Hassenzahl 2003; Schoenung 2001; Kamibayashi et al. 2002; Boyes 2010)
	100		BOP	(Kamibayashi et al. 2002)
50			BOP	(Boyes 2010)
	100		BOP	(Gyuk and Eckroad 2003)
	150-450		PCS[c]	(Gyuk and Eckroad 2003)

(a) More reliable 2007 numbers.
(b) Reliable – 2006 Long Island Bus actual installation numbers.
(c) For short duration application, cost is low; for long duration, cost is higher.

2.11.2 Fixed O&M Cost

The PCS consists of equipment necessary for energy transfer between the grid and ESS. The BOP is a catch-all for anything not covered by the PCS. The O&M costs for BOP have not been included in this analysis, since such costs are expected to be uniform across all technologies. In the next analysis, we plan to include uniform BOP costs, since it does affect the price tag for each technology. For the purpose of this study, we used $2/kW-year as the fixed O&M cost (Gyuk and Eckroad 2003).

2.11.3 Efficiency

The specific PCS round-trip efficiency was estimated to be 0.95. The round-trip efficiency is expected to change as a function of charge and discharge rate. For this analysis, the efficiency is kept constant for all rates.

2.12 Technology and Manufacturing Readiness Levels

Table 2.9 provides a short description of technology readiness levels (TRL) (DOE 2009), while Table 2.10 addresses manufacturing readiness levels (MRL) (DOD 2010). TRL 1 represents a technology still at the basic research level, while TRL9 indicates the system is ready for full commercial deployment. All the energy storage options included in this report are at least at the prototype level TRL 6, with Na-S, Li-ion, and flywheels performance validated in various demonstration projects (TRL 7). Pumped hydro systems are the most widely deployed and have been assigned the highest TRL of 9, while redox flow batteries are assigned the prototype level of TRL 6. The MRL assignments closely track the TRLs assigned to each storage system. MRL1 corresponds to feasibility assessed stage, while MRL10 indicates the technology has ramped up to full rate production. CTs, combined cycle systems, PH and CAES systems have been assigned MRL10. This is due to the site-specific consideration that has to be taken into account, thus adding a layer of complexity. Li-ion batteries have been assigned MRL6, with the expectation that with higher penetration of battery powered vehicles, this level will increase to MRL9 in about 2 years. Na-S batteries currently are manufactured by only one vendor, and hence have been assigned MRL6. For flywheels, rotors made of novel materials such as graphite and carbon nanotubes are expected to be incorporated to increase energy density and life, while reducing cost. Redox flow batteries, while being demonstrated at various sites, also have room for improvement in terms of materials selection and cell design. Both flywheels and redox flow batteries have been assigned MRL5.

Table 2.9. Description of TRL.

TRL	Description
TRL 1	Basic Research
TRL 2	Applied Research
TRL 3	Critical Function or Proof of Concept Established
TRL 4	Laboratory testing/Validation of Component(s)/Process(es)
TRL 5	Laboratory Testing of Integrated/Semi-Integrated System
TRL 6	Integrated Pilot System Demonstrated
TRL 8	System Incorporated in Commercial Design
TRL 9	System Proven and Ready for Full Commercial Deployment

Table 2.10. Description of MRL.

MRL	Description
MRL 1	Manufacturing feasibility assessed
MRL 2	Manufacturing concepts defined
MRL 3	Manufacturing concepts developed
MRL 4	Laboratory manufacturing process demonstration
MRL 5	Manufacturing process development
MRL 6	Critical manufacturing process prototyped
MRL 7	Prototype manufacturing system
MRL 8	Manufacturing Process Maturity Demonstration
MRL 9	Manufacturing processes proven
MRL 10	Full rate production demonstrated and lean production practices in place

3.0 Technology Cost and Performance Characteristics

Energy storage devices, unlike electric generators, have two capability ratings: 1) the power rating, expressed in kW or MW and the energy rating, expressed in kWh or MWh. This poses a challenge when comparing energy storage equipment with generators, which generally are not energy limited. To fully describe the incremental cost of an energy storage device, generally two specific cost indices must be used: cost per unit power ($/kW) and cost per unit energy ($/kWh). The literature is relatively inconsistent in this regard. Often, battery devices are characterized by their incremental cost per unit energy ($/kWh) masking the cost associated with the BOP and power conditioning system, which is scaled by the unit of power, or $/kW. The costs for PH projects are most commonly specified in $/kW, with a cost of $10/kWh assigned to the energy component. In most cases, it is determined by the topology of a given location, which sets the size of the reservoir. The same applies to CAES also, with a nominal cost assigned to reservoirs for compressed air storage. For flywheels and redox flow batteries, independent costs per unit power and energy have been provided. For the purpose of this report, a methodology of describing the incremental cost of energy storage devices was used that reveals both the cost that scales with the power rating ($/kW), and the cost that scales with energy content of the device ($/kWh).

To determine capital costs, the energy storage device has to be sized based on the power <u>and</u> energy needs of the application. This means that the capital cost has two components: one that scales with unit power (kW) estimating the cost for the PCS, and the other that scales with unit energy (kWh), which estimates the cost associated with the storage component of the system. To provide any incremental cost, either valued in $/kW or in $/kWh, one needs to estimate the total system cost and then and only then can the incremental cost be derived. However, it should be noted that it is meaningless and often misleading to compare two storage technologies for totally different application on the basis of one incremental cost.

The battery costs are typically given in $/kWh, which can be converted to $/kW, where the kW is rated power of the battery. For example, for a 1-kW, 4-kWh system, $1000/kW as a power-related cost corresponds to $250/kWh on a stored energy basis.

Typically, *rated power* is continuous power, and is defined as power that can be sustained for at least 15 minutes. *Peak power* typically is defined as pulse power for 2-second duration in the transportation sector. The ratio of peak power/rated power is a function of battery chemistry and design.

3.1 Summary of Capital, O&M Costs, and Efficiency for Batteries and PH Systems

Based on the values obtained from an extensive literature review and through many consultations with domain experts, Table 3.1 summarizes the values used in this study, with 2020 values shown in parentheses. The range of capital costs for years 2011 and 2020 are provided in Table 3.2.

The TRL and manufacturing readiness level (MRL) for each energy storage option are also included. TRL1 represents a technology still at the basic research level, while TRL9 indicates the system is ready for full commercial deployment. This study assumes that technologies with low TRL and MRL scores have further room for improvement in cost reduction, which are reflected in lower 2020 costs relative to 2011 costs. Table 3.1 suggests that there is significant room for cost and performance improvements of the less mature technologies (compressed air and batteries); while PH technologies, due their maturity, are not likely achieve cost reduction – at least, at the same rate possible with the nascent battery technologies.

3.1.1 Explanation for Cost Spread

The cost for installed Na-S systems has been provided in terms of $/kW, with the cost ranging from $2400-$4300/kW (Nourai 2007; Kishinevsky 2006; NGK 2007). The battery cost is estimated to be 50 percent of the installed cost. For 2011 costs, the battery costs, including non-recurring engineering support, are estimated to be 80 percent of installed costs, while for 2020, the battery costs are expected to be 50 percent of current installed costs.

For compressed air, the range of costs from various sources in the time frame 2003 to 2011 was $300-$1200/kW, with the cost increasing with time as experience is accumulated. In the time frame 2007-2010, most costs were in the $800-$850 range, with one estimate being $1140/kW in 2011 excluding storage costs. Hence for year 2011, the range was set at $850-$1140. For year 2020, some advanced low cost concepts proposed (Nakhamkin 2008, 2009, 2010) were also considered, with the range set at $500-$1140/kW.

For flywheels, costs are reported as total $/kW. As discharge time increases, total $/kW would increase. In the time frame 1999-2011, a wide range of $250-$3000/kW has been reported. The unit energy cost using steel rotors is about $148/kWh, while carbon rotors cost $350-$380/kWh. The current total cost for a 1-MW, 250-kWh system from Beacon Power is $1000/kW, which corresponds to a unit power cost of $865/kW assuming $148/kWh for the energy component. A range of $965-$1590/kW has been set for current unit power costs, with a unit energy cost of $148/kWh using steel rotors. For the year 2020, based on literature and telephone conversations, the range was set at $200-$865/kW, with a unit energy cost range of $81-$148/kWh (lower cost corresponding to graphite fiber rotors).

Table 3.1. Summary of Capital and O&M Costs for Technologies Analyzed. Note values are representative for 2011 technologies. 2020 values are in parentheses.

Parameter	Na-S Battery	Li-ion Battery	Pumped Hydro	Combustion Turbine	CC	Demand Response	CAES	Flywheel	Redox Flow Battery
TRL	7	7	9	9	9	6	8	7	6
MRL	6	6	7	10	10	2	7	5	5
Battery Capital cost $/kWh(a)	415(290)	1000 (510)	10				3	148 (115)	215 (131)
System Capital cost $/kW			1750 (1890)	1009 (990)	Not used	620	1000 (850)	1277 (610)	1111 (775)
PCS ($/kW)	220 (150)	220 (150)							220 (150)
BOP ($/kW)	85 (50)	85 (50)						85 (50)	85 (50)
O&M fixed $/kW-year	3	3	4.6	10.24	14.93		7	18	39.5 (5)
O&M fixed $/kW-year (PCS)	2	2							2
O&M variable cents/kWh	0.7	0.7	0.4	0.9	0.4		0.3	0.1	0.1
Round-trip efficiency	0.78	0.80	0.81	0.315			0.50	0.85	0.75

(a) The battery capital cost is per unit energy, while PCS and BOP costs are per unit power.

Table 3.2. Table Range of Capital Costs for Years 2011 and 2020.

Technology	2011 Range		2020 Range	
	$/kWh	$/kW	$/kWh	$/kW
Na-S	257-491		181-331	
Li-ion	850-1000		290-700	
Pumped Hydro	10	1500-2300	10	1640-2440
Compressed air	3	850-1140	3	500-1140
Flywheel	148	965-1590	81-148	200-820
Redox flow battery	173-257	942-1280	88-173	608-942

For redox flow batteries, costs were estimated based on currently available estimates for stack components and chemicals, and projected improvements in cost and performance. Our analysis indicated unit power cost range of $600 to $1250/kW and energy cost of $80 to $260/kWh. The current costs were estimated to be bounded by the mid-points and the higher ends of these ranges, while 2020 costs were correspondingly bounded by the lower ends and the mid-points.

For Li-ion batteries, the costs estimates in the years 2009 to 2010 were $850 to $1000/kWh, while longer range estimates from the literature were in the $290 to $700/kWh range.

For PH, in the years 1996-2006, costs were in the $600-$1000/kW range. Conversations with Rick Miller (Renewable Energy Services) and e-mail exchanges indicated cost of $1500-$2300/kW. Accounting for potential technological improvements being offset by increasing material costs and increasing trend of PH system prices, the cost for 2020 was estimated to be $1640-$2440/kW.

4.0 Cost Comparison to SNL/EPRI Database

The 2013 Electricity Storage Handbook (SNL/EPRI, 2013), which has not yet been released, estimates the cost of ESSs by surveying vendors of various technologies for different applications. A brief comparison between the results of this reference and the present work is given below.

Frequency regulation and renewable integration were chosen as the most appropriate applications for the comparison of storage costs. Where information for a particular technology was not available, bulk storage was considered for comparison. For example, NaS, PH, vanadium redox costs are given for only bulk storage with duration of 6-8 hours. Li-Ion and flywheels costs are provided for only frequency regulation/renewables integration. Where costs are provided for both applications, a comparison of these costs was done to provide perspective on how the Handbook cost estimates vary with application.

The Handbook chose Na-S, PH, vanadium redox for bulk storage with 6-8 hours duration. The current commercial Na-S system is available only in the 6-8 hour duration range. Our study assumes availability of Na-S systems at an energy/power ratio of 1 in 2020. Pumped hydro systems were considered in the Handbook only for 6-8 hour duration. Due to high capital costs involved to build large PH plants, the Handbook assumes pumped hydro would not be cost effective for low duration applications. In our analysis, considering power and energy in the GW range, we assumed PH would be feasible for E/P of around unity. It should be noted that even though the duration is only 15-20 minutes during each discharge, accounting for system efficiency, the energy content of the PH is higher than the 15-20 minutes that the Handbook assumes, because PH may operate for a week before needing to be recharged. The Handbook assumes vanadium redox flow batteries are suitable only for durations in the 6-8 hour range. In contrast, our analysis assumes redox flow batteries have the distinct advantage of being used in either power-intensive or energy-intensive applications.

In the Handbook, while the duration for bulk storage was considered in the range 6-8 hours, storage capacity varied for frequency regulation. For CAES, the same system (100 MW, 8h) was used for both applications. For sodium metal halide battery systems, a 2- hour duration was used for frequency regulation, while 0.3-1h was used for Li-ion and advanced lead-acid batteries. The zinc bromine system considered had 1h and 5h duration. Subsequent communication from the authors indicated the systems chosen were actual available systems. For each technology, the E/P ratio was varied based on cost effectiveness as determined by the manufacturers of the ESS.

Separate costs for unit power and energy costs were provided for batteries. While this is understandable for redox flow batteries, it was not clear what the separate costs represent for Li-ion, advanced lead-acid batteries, sodium sulfur, zinc bromine, and sodium metal halide batteries, where the power and energy costs cannot be separated. Subsequent communication from the authors indicated that the unit power costs included PCS costs, and costs for conditioning the power to load requirements. They also included other control, communication and monitoring components, and other building & ancillary subsystems as heating and cooling subsystems. PNNL's PCS costs are laid out as a separate line item. While the Handbook provides total costs per unit power and energy, our work does not consider total cost, since the total cost is a function of the E/P ratio. Hence the total costs from the Handbook have not been considered, except in situations where unit power and energy costs for the two studies diverge, but the total system cost are in agreement.

Table 4.1 provides the cost comparison for the two studies. For the PNNL numbers, the PCS costs, where applicable, are included in the unit power costs. The costs for Na-S are quite similar. The unit power costs are more than double the PCS costs estimated by PNNL. That is probably because the PCS costs scale with power. For our large systems, it is assumed the PCS costs will be much lower. The Handbook refers to specific system costs, where the PCS costs may be for a much lower power rating than that considered in the PNNL study. The same conclusion holds for the unit Li-Ion power costs. For Li-ion battery systems, the Handbook provides a wide range of unit energy costs. After ignoring the extreme costs at the low and upper end, the unit energy cost of $950-2000/kWh compares favorably with our $1000/kWh estimate.

The unit power costs for PH in the Handbook is about 55 percent of PNNL's estimate of $1750/kW, while the unit energy cost of $125/kWh is much higher than our estimate of $10/kWh. For an 8-hour application, for which the PH costs were provided, the estimated total costs are nearly the same, at about $1700/kW (Handbook) and $1830/kW (PNNL). The discrepancy can be explained by the fact that the Handbook uses estimates from single vendors for specific sizes. The Handbook authors indicated that they will investigate this issue further.

Table 4.1. Comparison of Handbook and PNNL numbers.

	NaS		**Li-Ion**		**PH**		**CAES**		**Fly wheel**		**Van Redox**	
	PNNL	Hand book	PNNL	Hand book	PNNL	Hand book	PNNL	Hand book	PNNL	Hand book	PNNL	Hand book
$/kW	220	516	220	514-779	1750	938	1000	921	1277	867	1330	635
$/kWh	415	426	1000	950-2000	10	125	3	15	148	5168	215	620
BOP $/kW	85	a	85	a					85	(a)	85	(a)
O&M fixed $/kW-year	3	4	3		4.6	16	7	5	18	6	39.5	4
O&M variable cents/kWh	0.7	0.5	0.7		0.4	0	0.3	0.35	0.1	0.03	0.1	0.5
Round-trip efficiency %	78	75	80	90	81	81	50	74	85	85	75	75

(a) The Handbook does not provide BOP costs. Installation costs are provided separately

The Handbook's unit power cost for flywheels is about 68 percent of the PNNL estimate of $127/kW, while the unit energy cost of $5168/kWh was much higher than the PNNL estimate of $148/kWh. This could be due to the fact that the Handbook estimate includes information from only one supplier.

The vanadium redox flow battery costs for a 5-hour system are $635/kW and $620/kWh respectively. The corresponding PNNL numbers are $1111/kW and $215/kWh respectively. Including PCS costs, the unit power costs for the PNNL study is $1330/kW, which is twice that of the Handbook number. For the unit energy cost, the wide variation in chemical costs could be the reason for the discrepancy. The discrepancy again appears to be due to the fact that only one supplier information was included in the redox battery estimate in the Handbook. The PNNL estimate was the result of an extensive cost study that included component costs, taking into account the performance of the ESS for this application.

Comparison of the Handbook estimates for advanced lead-acid batteries, sodium metal halide and zinc bromine for the two applications showed that as a general rule of thumb, the unit energy and power costs decreased with increasing energy and power. For zinc bromine, two types of storage units were considered, one with low unit power and energy costs, and the other with high unit power and energy costs.

The O&M costs in the Handbook are nearly the same as those of the PNNL study, except for the vanadium redox flow battery having a 10X higher cost of $39.5/kW-year in the PNNL study for the year 2011. The O&M costs reported in the literature ranged from $5-39.5/kW-year. Due to the novelty of the technology, the PNNL study assumed the higher O&M cost for redox flow batteries in the year 2011. Considering most storage O&M costs were around $4-6/kW-year, it appeared to be logical that in the year 2020, the O&M costs could dip to this range. The Handbook O&M estimate uses this low end, which probably is more appropriate for the year 2020.

The round-trip efficiencies for most technologies are quite similar for both studies. The only exception is the 90 percent efficiency estimated in the Handbook for Li-ion storage system, while the PNNL study estimates 80 percent. The Handbook efficiency was based on a C-rate discharge. Because frequency regulation is a power-intensive application, PNNL considers it appropriate to use lower round-trip efficiency.

In summary, the cost values from both studies agree for the most part. Individual discrepancies may be attributed to different sizes being used in each study. The Handbook further provides costs for actual systems as provided by the vendors. Because these are specific to the vendor and system size for the technology in question, this further added to the resulting differences developed in the two Assessments.

5.0 Definition of Technology Options

The set of technologies mentioned above can be applied individually or in combination with other technologies. Technology 'packages' of two technologies are investigated. These packages can be thought of as a portfolio of resources that, in most cases, may be dispersed throughout the regions examined in this report. Only in the cases of PH and CAES energy storage would a single location, or potentially multiple locations, be viable based on the topology to support upper and lower reservoirs (for PH) or the geological structure needed for storing compressed air (for CAES). For most of the technologies, the actual capacity will be widely dispersed. This is particularly the case for DR (demand response). Table 5.1 below shows the 16 single technology packages, which we will call 'cases.'

Seven hybrid storage combinations comprised of two technologies were explored. The selection of the pairing was arbitrary and somewhat guided by the intuition that a technology designed for a high power application would be complementary and perhaps more cost-competitive when paired with a high energy capacity technology. We defined seven technology pairings (C10 through C16) that were studied to find optimal sizes of technology in a pairing that minimize the total LCC.

Table 5.1. Definition of Technology Cases.

	Case	Technology	Comments
Individual Technologies	C1	Combustion turbine	Conventional technology considered as the reference case.
	C2	Na-S	Sodium sulfur battery only.
	C3	Li-ion	Lithium-ion battery only.
	C4	Flywheel	Flywheel only.
	C5	CAES with two2 mode changes	CAES with a 7-minute waiting period for mode changes (compression-generation and vice versa). Balancing services will be provided during compression mode at night (8 pm-8 am) and during generation mode during the day (8 am-8 pm). Na-S battery is assumed to make up operations during 7 minute waiting period.
	C6	Flow battery	Flow battery only.
	C7	PH with multiple mode changes	PH with a 4-minute waiting period for mode changes (pumping-generation and vice versa). This machine allows multiple mode changes during the day. Na-S battery is assumed to make up operations during 4 minute waiting period.
	C8	PH with two2 mode changes	Same as (C7), except only two mode changes. Balancing services will be provided during pumping mode at night (8 pm-8 am) and during generation mode during the day (8 am-8 pm). Na-S battery is assumed to make up operations during 4 minute waiting period.
	C9	DRDR (demand response)	Demand response only. This assumes that balancing services will be provided as a load. Only considered is PHEV charging at home and work. Resources are expressed in MW of DR capacity as well as in numbers of PHEV with demand response capability.
Technology Packages	C10	Na-S DR	Sodium sulfur battery and DR combined.
	C11	Li-ion DR	Lithium-ion battery and DR combined
	C12	CAES Flywheel	CAES with no constraints for mode changes with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.
	C13	PH with multiple mode chances Na-S	PH with no constraints for mode changes with Na-S battery. The balancing requirement is allocated to each technology according to minimum cost.
	C14	PH with two2 mode changes Na-S	PH with two mode changes per day (see C8) with Na-S battery. The balancing requirement is allocated to each technology according to minimum cost.
	C15	PH with multiple mode chances Flywheel	PH with no constraints for mode changes with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.
	C16	PH with two2 mode changes Flywheel	PH with two mode changes per day (see C8) with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.

6.0 Economic Analysis Methodology and Results

6.1 Cost Analysis Framework

That energy storage can enable higher levels of wind and solar energy integration is a necessary but not singular condition for market acceptance. There are competing technologies (e.g., CT and DR) that could be used similarly to address technical issues resulting from the variable nature of wind and solar energy.

To examine the competitiveness for energy storage, the analytical framework for Doane et al. (1976) was adapted and the parameters outlined later in this report were used to conduct an economic assessment of the following nine alternative technology cases:

1. CT
2. Na-S batteries
3. Li-ion batteries
4. Flywheels
5. CAES
6. Redox (reduction-oxidation) flow batteries
7. PH with multiple mode changes per day
8. PH with 2 mode changes per day
9. DR.

The cost model used to support this analysis examined all initial and recurrent costs, property and income taxes, depreciation, borrowing costs, and insurance premiums. Major cost assumptions are presented in Table 6.1. The cost model presents results in 2011 dollars, and treats interest and inflation in a systematic manner and distinguishes between costs that occur annually and those that occur in a single year. The cost model generated annualized cost and total LCC estimates for each case, as required to meet the balancing requirements for each of the four WECC sub-regions (NWPP, RMPA, CAMX, and AZNM), the ERCOT, and the 14 EI sub-regions (MROE, MROW, NEWE, NYLI, NYUP, RFCE, RFCM, RFCW, SPNO, SPSO, SRCE, SRDA, SRGW, and SRVC) included in this assessment. See Figure 2.1, Volume 1 of the Assessment for a geographic overview of each sub-region.

6.2 Optimizing the Battery Capacity

An important factor in minimizing the costs associated with alternative energy storage cases is optimally sizing the battery capacity. In effect, one could size up the energy storage capacity to reduce the DOD and increase the economic life of the battery systems, as demonstrated in the calculations performed by the research team in Table 6.2. Increasing the battery capacity drives up the initial capital costs but reduces the DOD requirements and extends the life cycle of batteries, thus reducing interim capital costs. To account for natural aging the maximum life cycles for Na-S, Li-ion, and redox flow batteries were constrained to 13, 10, and 25 years, respectively. The maximum life cycle for flywheels was constrained to 25 years. Table 6.2 presents the data computed for Case 3 (Na-S plus CC).

Table 6.1. Utility Description Data and General Economic Parameters

Utility Description Data	
System Operating Lifetime	50 years
Effective Income Tax Rate	40%
After Tax Weighted Cost of Capital	8%
Annual Other Taxes and Insurance Premiums as Fraction of Capital Investment	2%
Base Year for Dollars	2011
General Economic Parameters	
Rate of General Inflation	1.8%
Escalation Rate for Capital Costs	1.8%
Escalation Rate for Operating and Maintenance Costs	1.8%
Escalation Rate for Fuel Costs	3.2%

Table 6.2. Relationship between DOD, Battery (Na-S) Capacity, and Life Cycle

DOD	Battery Capacity(MWh)	Life-Cycle (Years)
0.05	11,748	240
0.10	5,874	82
0.15	3,906	43
0.20	2,937	27
0.25	2,350	18
0.30	1,938	12
0.40	1,468	7.5
0.50	1,175	5.0
0.75	781	2.7
0.85	691	2.3
0.95	618	2.0

DOD, battery capacity, life cycle, and discount rates are the parameters used to establish the optimum battery size based on an assessment of the present value LCC for each DOD level, as demonstrated in Figure 6.1. In effect, upsizing the battery would increase initial capital costs but would extend the useful life of the technology, thus requiring fewer battery purchases over the 50-year analysis time horizon. A 50-year analysis time horizon was selected because it corresponds to the useful life of pumped hydro, which is the asset reviewed in this assessment with the longest expected life. While essential, the data in Table 6.2 are not sufficient to determine the optimum battery capacity required to minimize costs because you must build these values into the cost model to determine their impacts on costs. Though increasing the depth of discharge reduces the initial capital costs associated with investments in energy storage options, the life cycle falls significantly at higher DOD levels, thus requiring numerous interim capital investments in future years. Thus, a system that is upsized with a useful life of 10 years would result in relatively high capital costs but would require only five battery purchases over the 50-year analysis time horizon. On the other hand, a battery system with a 5-year life cycle would be smaller with lower initial capital costs but the service provider would need to purchase ten battery systems over the 50-year analysis time horizon. The cost model would calculate present value costs for each of these systems and the least cost approach would be compared against those chosen for the other cases. Tables relating DOD to battery capacity and life cycle were constructed for all battery and flywheel system.

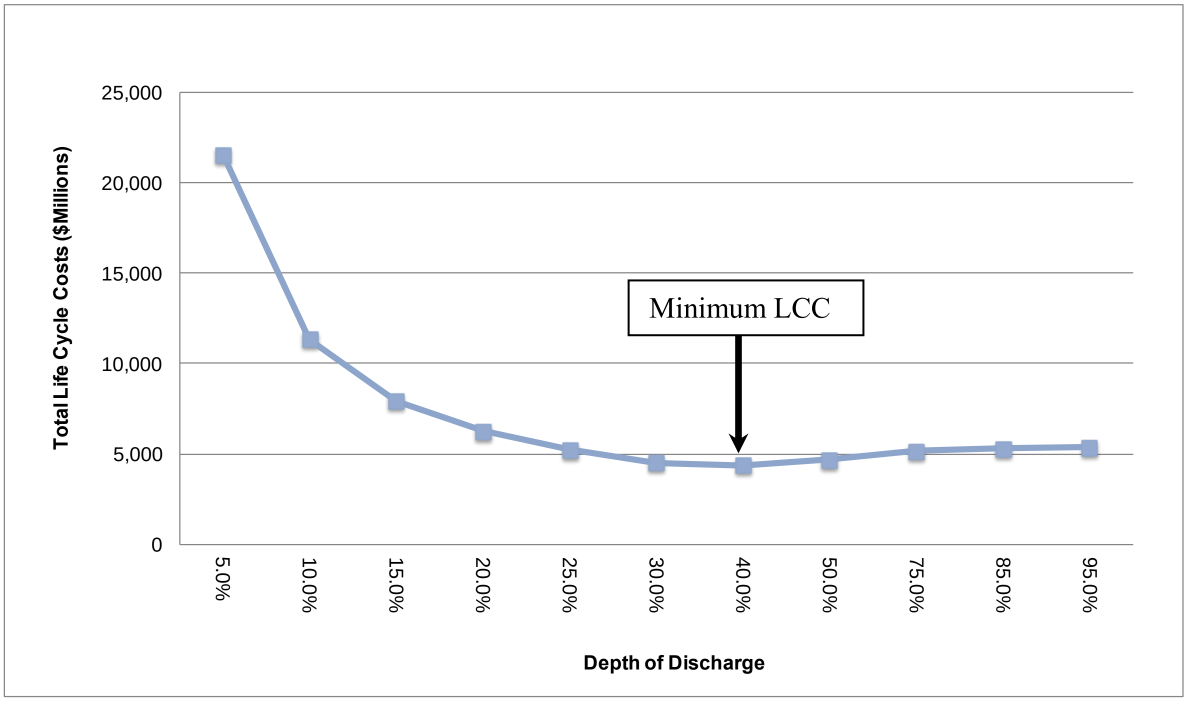


Figure 6.1. Case 3 LCC Estimates for Li-Ion Batteries for NWPP

As shown, this figure demonstrates a minimum in the LCC (objective function) is achieved at 40% under Case 3. This means that over-sizing the Li-ion storage device by a factor of 2.5 (1/0.40) would yield the lowest LCC given all of the other assumptions made. It should also be noted that the life-cycle costs remain rather flat over a wide range of DODs (25% to 100%) indicating that the LCC is fairly robust against changes in the size of the storage system. This finding suggests that the interim capital cost reductions realized by upsizing the system in order to extend the battery life cycle is largely if not entirely offset by additional initial capital costs. The curve, which rises when the DOD falls below 40%, does so because we assume a 10-year economic life for Li-ion batteries regardless of use. Thus, upsizing the battery fails to extend the life cycle beyond the 10-year maximum when DODs fall below 40%. This is of significant importance for long-term infrastructure planning investments. It indicates that over the long-term an investment in battery storage with a DOD-dependent lifetime is relatively insensitive to over-sizing.

For each of the nine cases, costs are computed for battery DODs ranging from 5% to 95%. Results for the NWPP are presented in Table 6.3. As shown, the cost minimizing DODs fall between 20% and 40% for cases 2 and 3. For the other cases considered in this analysis, the cost minimizing DOD ranges between 85% and 95%. With the exception of case 6, the higher DODs under these scenarios are due to the heavy reliance on PH or CAES with minimal demand placed on the battery systems. In the absence of heavy use, these systems can withstand higher depths of discharge. For Case 6, the higher depth of discharge is due to the ability of the redox flow battery to withstand higher levels of usage (DOD) with minimal deterioration.

Table 6.3. Cost Minimizing DOD, Battery Capacity, and Economic Life by Case

Case	DOD	Battery Capacity (MWh)	Economic Life[(a)]
1	--	--	--
2	30%	1,978	13.0
3	40%	1,468	7.5
4	95%	593	25.0
5	--	--	--
6	95%	650	25.0
7	85%	162	12.9
8	95%	51	13.0
9	--	--	--

(a) The maximum battery life for flywheels and the redox flow batteries is 25 years. The maximum battery life for Na-S and Li-ion batteries is 13 and 10 years, respectively.

6.3 Economic Parameters

The cost framework outlined in Section 4 and the cost model supporting this research rely on a number of assumptions regarding major cost elements, including capital costs, O&M costs, fuel costs, and emissions costs. Costs are segmented according to each of these four cost categories within each of the aforementioned nine technology cases. The remainder of this section details the assumptions underlying each cost component.

6.3.1 Capital Costs

Section 3.0 presents capital cost estimates for each technology, and documents the basis for each estimate. Based on the economic lives of each technology, interim capital costs are incurred as necessary to provide required service over the 50-year analysis time horizon. For each option, results are examined using forecasted 2020 prices. In all cases, with the exception of sensitivity analyses presented in Section 8.3, present value costs of investments made in future years are discounted at a nominal rate of 8.0%.

The bases of the capital costs associated with each battery technology, as well as flywheels, CAES and PH, are outlined in Section 3.0. In addition to these capital costs, one case considers the capital costs of CT and another case includes the capital costs associated with DR. Note that the costs of implementing DR are assumed to be $50.70 per kW-year (EPRI 2009a). Over 50 years, the present value of DR capital costs is $620 per kW, discounted at 8.0%. Combustion turbine capital costs are estimated at $990 per kW based on the latest estimates presented in the 2011 AEO (DOE/EIA 2011). In addition to these costs, PCS and BOP capital costs are included in all cases involving battery installations, and are estimated at $150 per kW and $50 per kW, respectively. No additional CC power plant capacity is required to meet the energy requirements set forth in this assessment. Therefore, CC plant capital costs are excluded from the analysis. The costs of operating those CC plants, however, are included in the cost estimates presented for each case.

The results of the LCC analysis are presented using both forecast 2020 prices and current 2011 prices. For Na-S batteries, 2011 prices are estimated at $415/kWh. The E/P ratio for Na-S batteries is currently 7, which corresponds to a price per kW of $2,905. The 2011 price scenario, while using current prices per kWh, is applied to future balancing requirements. While the scenario effectively does not assume that 2020 forecast price reductions are achieved, it does assume that a lower energy to power ratio of 1 can be achieved. The research team views this as a reasonable assumption given that sodium beta batteries are currently available at an E/P ratio of 1. Further, the power of the Na-S battery over a 15-minute time horizon is 5 times the rated power. With the peak power during balancing occurring for 2-3 minutes, it can be safely assumed that the battery can provide 5 times the rated continuous power. With the above noted, the design for the Na-S technology employed in both the 2020 and 2011 scenarios does not presently exist.

6.3.2 Operations and Maintenance Costs

For combustion and CC turbines, O&M costs are expressed in variable terms based on data presented in the 2011 AEO. For CT, fixed O&M costs are $10.24 per kW and variable O&M costs are $8.56 per MWh. CC O&M costs are estimated at $14.93 per kW and $3.54 per MWh for fixed and variable, respectively (DOE/EIA 2011).

For battery technologies, O&M costs were also split into fixed and variable components. The fixed component is incurred every year regardless of the energy requirement, while the variable component is proportional to electrical energy (kWh) throughput. Fixed O&M costs were estimated at $3.00 per kWh of energy storage capacity while variable O&M costs were estimated at $.007 per kWh for Na-S and Li-ion batteries. These costs are detailed in Section 3.3. In addition to these costs, PCS O&M costs are included and estimated at $2 per kW of installed capacity for Na-S, Li-ion, and redox flow batteries.

Pumped hydro, CAES, flywheel, and redox flow battery O&M costs are expressed in terms of fixed and variable components as well. Fixed O&M costs for PH, CAES, flywheel, and redox flow batteries are estimated at $4.60, $7.00, $18.00, and $5.00 per kW of installed capacity, respectively. Variable O&M costs are estimated at $.004, $.003, $.001, and $.001 per kWh of throughput for PH, CAES, flywheel, and redox flow batteries, respectively.

6.3.3 Fuel Costs

Fuel costs for each alternative were developed using average daily energy requirements as measured in million British Thermal Units (MMBTU). These energy requirements were generated based on the CT and CC turbine production schedules designed to meet load balancing requirements for the region and sub-regions in 2020.

In each scenario, fuel costs associated with CT alternatives are higher than those estimated for each of the CC turbine, CAES, flywheel, PH, or battery alternatives. Fuel cost differentials are due to varying heat rates, which are a function of energy efficiencies. The energy requirements of the CC plus battery alternatives were calculated as the product of the efficiency levels associated with each component.

Average daily energy requirements were expanded to annual energy requirements, which were in turn multiplied by natural gas prices ($4.94 per MMBTU in 2011 escalated at 3.2% over the 50-year analysis time horizon) to compute annual fuel costs for each alternative (DOE/EIA 2011).

6.3.4 Emissions Costs

Fuel combustion levels assigned through the approach described previously were used to establish emissions levels through the application of EPA coefficients for converting quadrillion BTU into metric tons, as outlined in Table 6.4 (EPA 1995). These emissions levels were, in turn, used to construct emissions cost estimates.

Prices for emissions allowances for NO_x, SO_2, and CO_2 are presented in Table 6.4. NO_x prices were obtained from the January-February 2010 NO_x Market Monthly Market Update (annual NO_x allowances) published by Evolution Markets (Evolution Markets 2010). SO_2 prices were also obtained through Evolution Markets in the January-February 2010 SO_2 Monthly Market Update. Prices for CO_2 allowances ($45 per ton) were derived from the Sixth Northwest Power Plan (Northwest Power and Conservation Council 2010).

Table 6.4. Emissions Cost Data

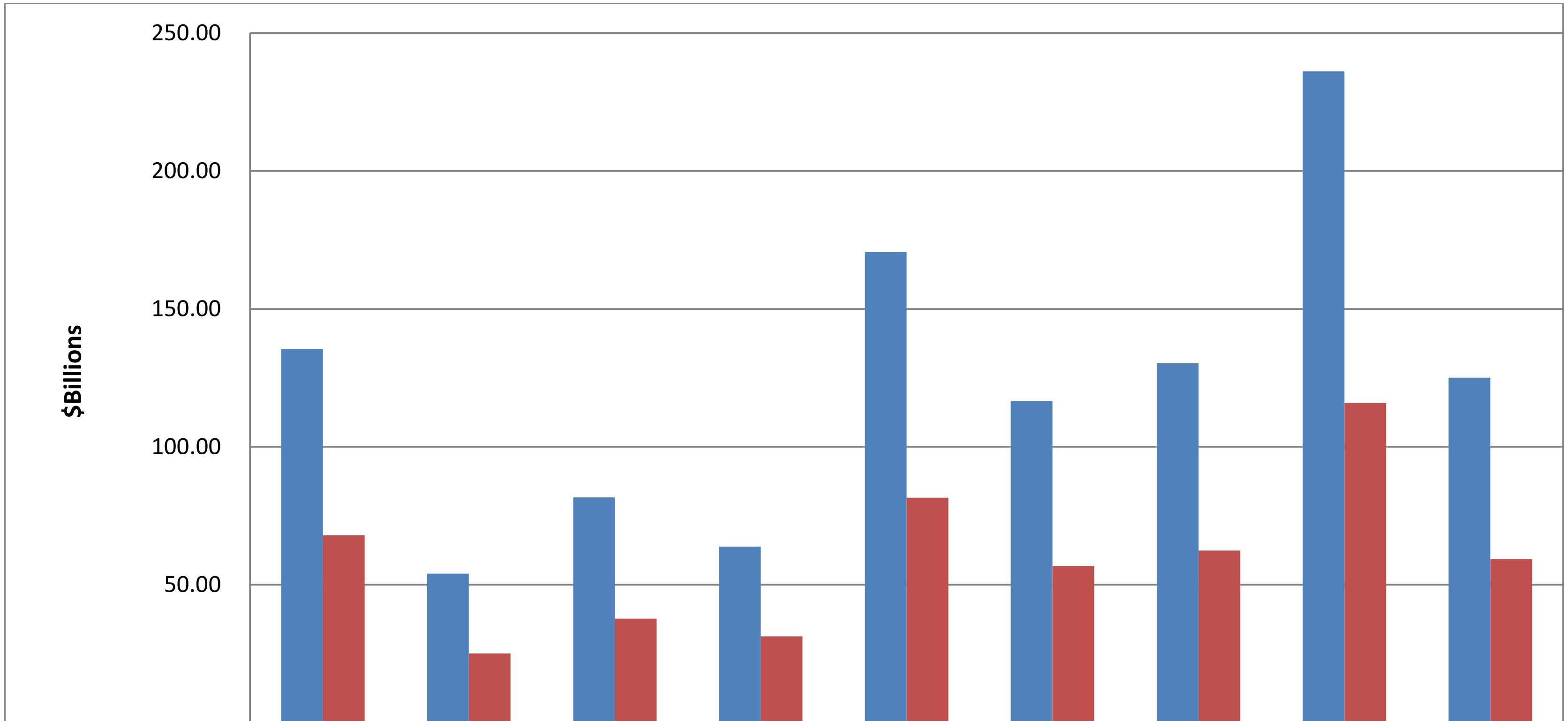
Emissions Data		SO_2	NO_x	CO_2
Allowances	$/metric ton	$71.75	$600	$45
EPA Coefficients	Metric tons/quadrillion Btu	267	978	53,060,000

6.4 Results

The economic assessment methodology detailed in the preceding section of this report was used to compute cost estimates for nine cases using combinations of several energy generation or storage technologies – CTs, CC, Na-S and Li-ion batteries, PH, CAES, flywheels, redox flow batteries, and DR. These cases are defined in Section 8.1. For each case, the objective was to meet the load balancing requirements for each of the four WECC sub-regions (NWPP, RMPA, CAMX, and AZNM), the ERCOT, and the 14 EI sub-regions (MROE, MROW, NEWE, NYLI, NYUP, RFCE, RFCM, RFCW, SPNO, SPSO, SRCE, SRDA, SRGW, and SRVC) included in this assessment.

Figure 6.2 presents the LCC results for all nine technology cases to meet all wind capacity and additional load and wind capacity forecast for 2020. The additional balancing scenario assumes that uncertainty tied to current load and wind capacity is addressed using existing grid assets. For the entire U.S., Case 2, which employs Na-S batteries , is the least cost alternative at $54.0 billion for total wind-related intra-hour balancing. Note that the values presented in in Figure 6.2 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon. The escalation rate used for both capital and O&M costs is 1.8% and we used an 8% nominal discount rate. Figures 6.3-6.5 presents the LCC results for the WECC, ERCOT, and EI, respectively.

Case 4, which consists of flywheels, represents the second most economical alternative with costs estimated at $63.85 billion. Case 4 costs exceed those estimated for Case 2 by 51.1%. The costs associated with the DR-only case (Case 9) are more than twice as much as those estimated for Case 2 and 95.9% higher than Case 4 estimates. The CAES case (Case 5) is also more expensive with estimated costs of $170.6 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $236.1 billion. Total costs under Case 6, redox flow batteries , are estimated at $116.6 billion. While Na-S batteries (Case 2) appears to be the most cost-effective option for balancing in both 2011 and 2020, this analysis assumes that Na-S batteries will be available in the required energy to rated power ratio of ~1:1. Currently, this ratio is about seven, thus requiring a battery seven times the size selected in this study. This is the main reason Na-S batteries are not competitive with CTs at present. If Na-S systems cannot be manufactured at energy to rated power ratios of 1 by 2020, flywheels (Case 4) would appear the most cost-effective option for both 2011 and 2020. Using 2011 prices, CAES (Case 5) and pumped hydro with multiple mode changes (Case 7), while costlier than flywheels (Case 4), are competitive with CTs (Case 1), while Li-ion systems (Case 3) are slightly costlier than CTs (Case 1). When using forecast 2020 prices, all energy storage options are competitive with CTs (Case 1), except CAES (Case 5) and PH 2-mode (Case 8). Even at the high end of the capital cost estimates, in 2020, Li-ion (Case 3) and flywheels (Case 4) are expected to be cost-competitive with CTs (Case 1), while flow batteries (Case 6) are expected to be only barely costlier.



	C1: Combustion Turbines	C2: Na-S	C3: Li-Ion	C4: Flywheel	C5: CAES	C6: Flow Battery	C7: PH Multiple Mode Changes	C8: PH 2 Mode Changes	C9: DR
Total Wind	135.48	54.03	81.62	63.85	170.61	116.61	130.24	236.15	125.06
Additional Wind	67.96	25.08	37.72	31.26	81.54	56.84	62.35	115.96	59.36

Figure 6.2. Total Life-cycle Costs for All Technology Cases - United States (Total and Additional Wind Scenarios)

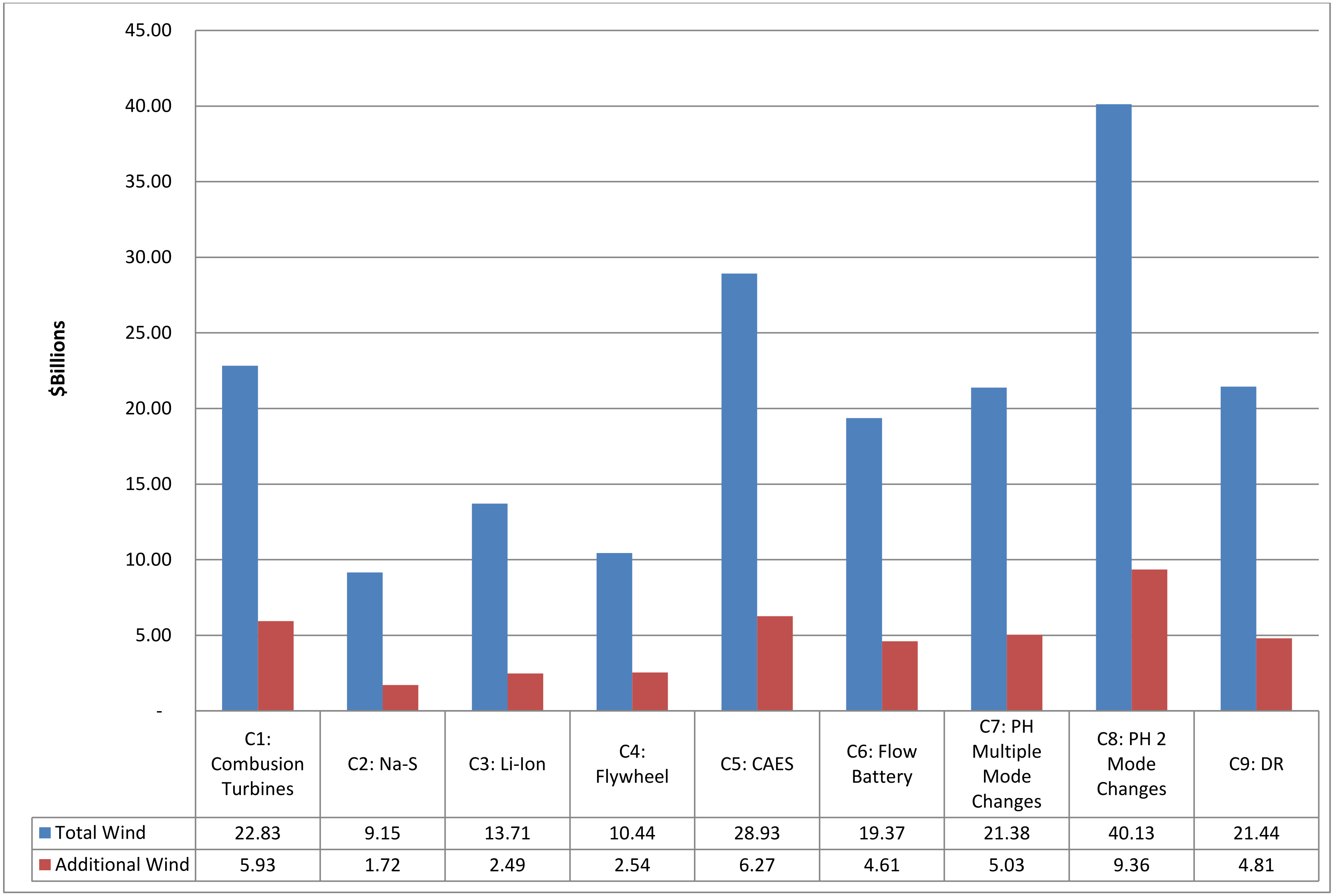
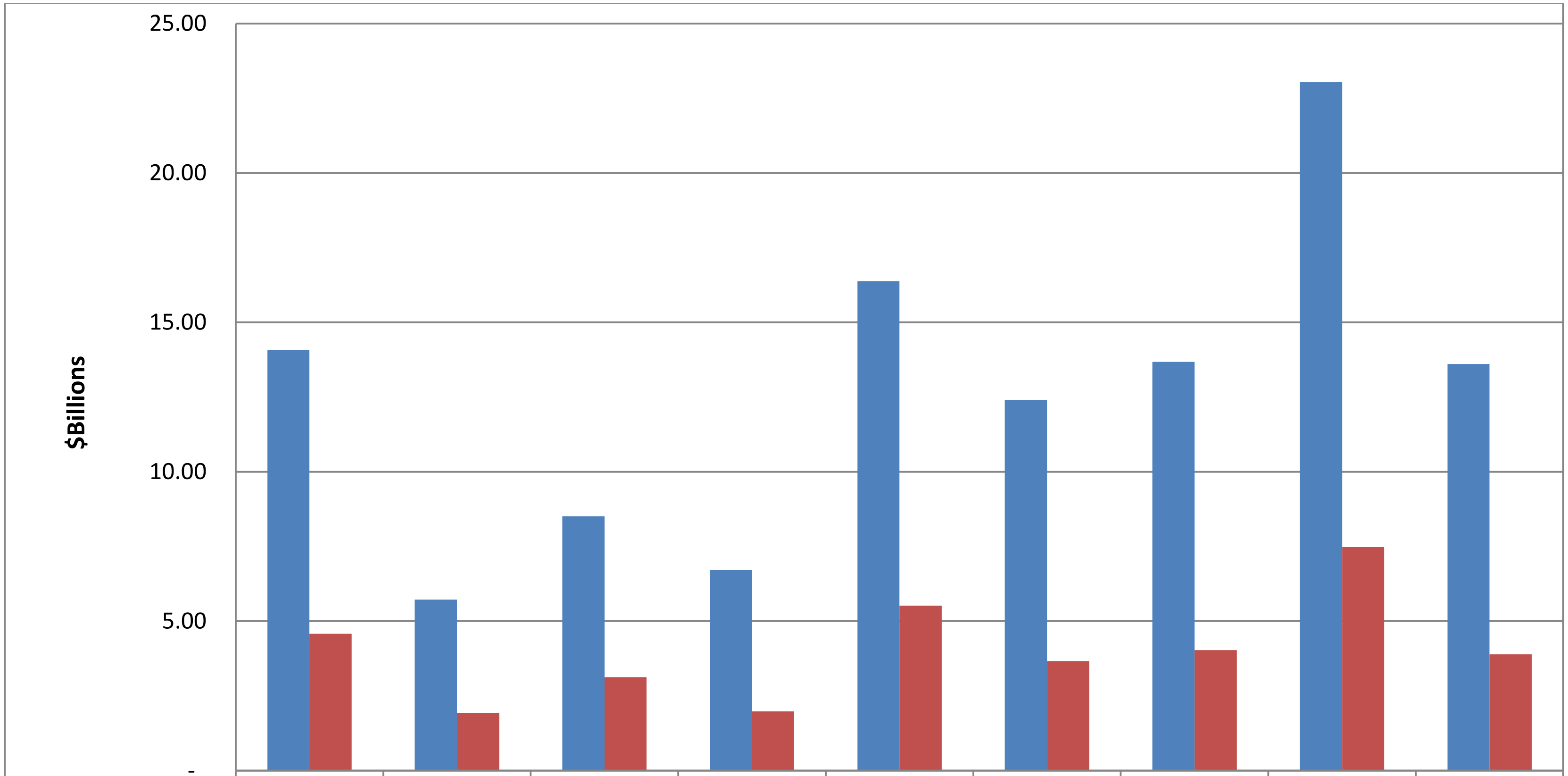


Figure 6.3. Total Life-cycle Costs for All Technology Cases - WECC (Total and Additional Wind Scenarios)



	C1: Combustion Turbines	C2: Na-S	C3: Li-Ion	C4: Flywheel	C5: CAES	C6: Flow Battery	C7: PH Multiple Mode Changes	C8: PH 2 Mode Changes	C9: DR
Total Wind	14.07	5.72	8.52	6.72	16.37	12.41	13.68	23.04	13.61
Additional Wind	4.58	1.93	3.13	1.99	5.52	3.66	4.03	7.48	3.89

Figure 6.4. Total Life-cycle Costs for All Technology Cases - ERCOT (Total and Additional Wind Scenarios)

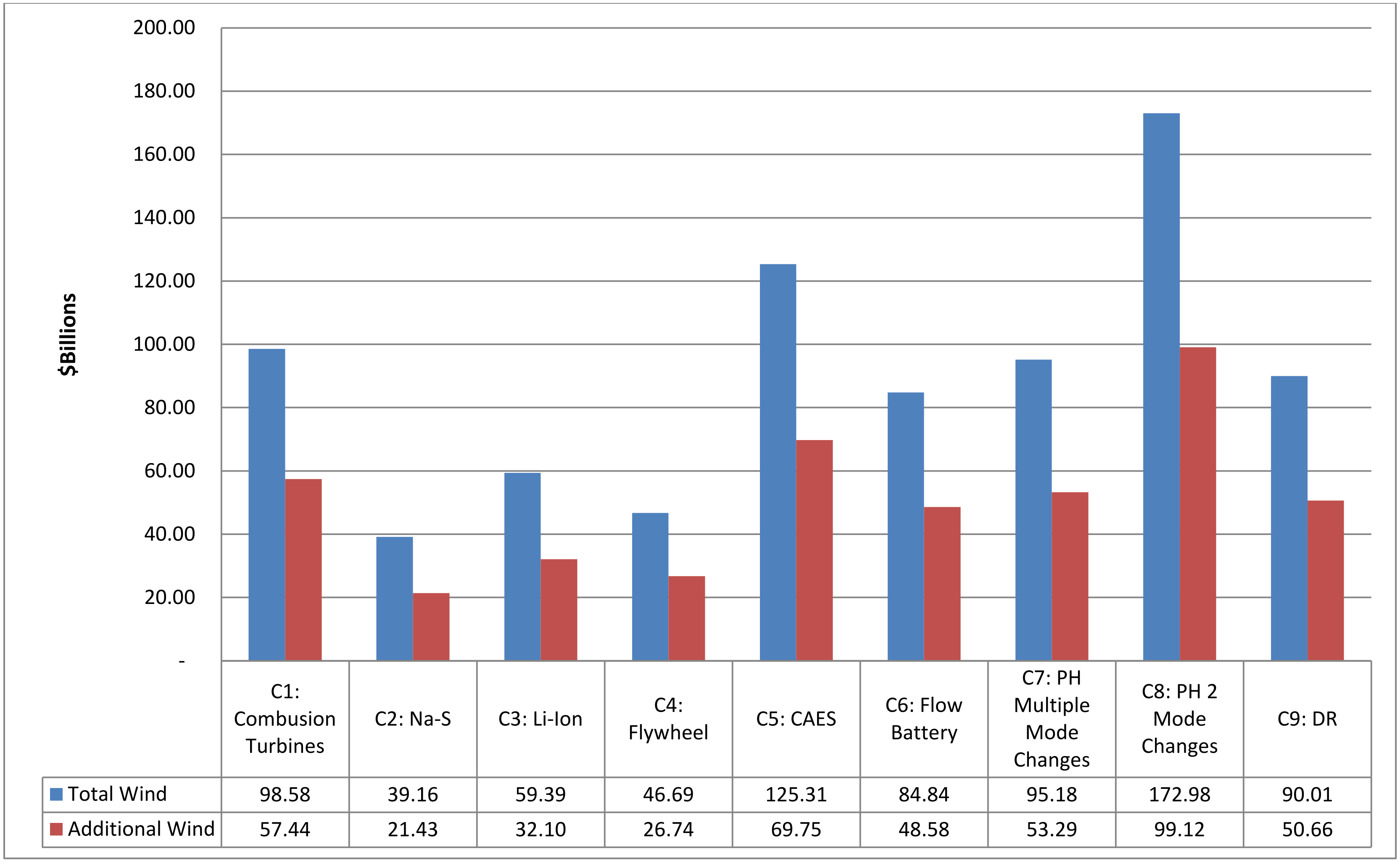


Figure 6.5. Total Life-cycle Costs for All Technology Cases - EIC (Total and Additional Wind Scenarios)

Figure 6.6 demonstrates that the LCC under the most economical case to address wind-related intra-hour balancing requirements is $9.2 billion (16.9%) in the WECC, $5.7 billion (10.6%) in the ERCOT, and $39.2 billion (72.5%) in the EI. In the additional wind scenario, costs forecast in the EI represent 85.4 percent of those estimated for the nation. The costs to address intra-hour balancing requirements under the additional wind scenario in the WECC are equal to 18.8% of those estimated for the total wind scenario. In the EI, where wind capacity is forecast to expand significantly, the additional wind scenario costs are equal to 54.7 percent of those estimated for the total wind scenario.

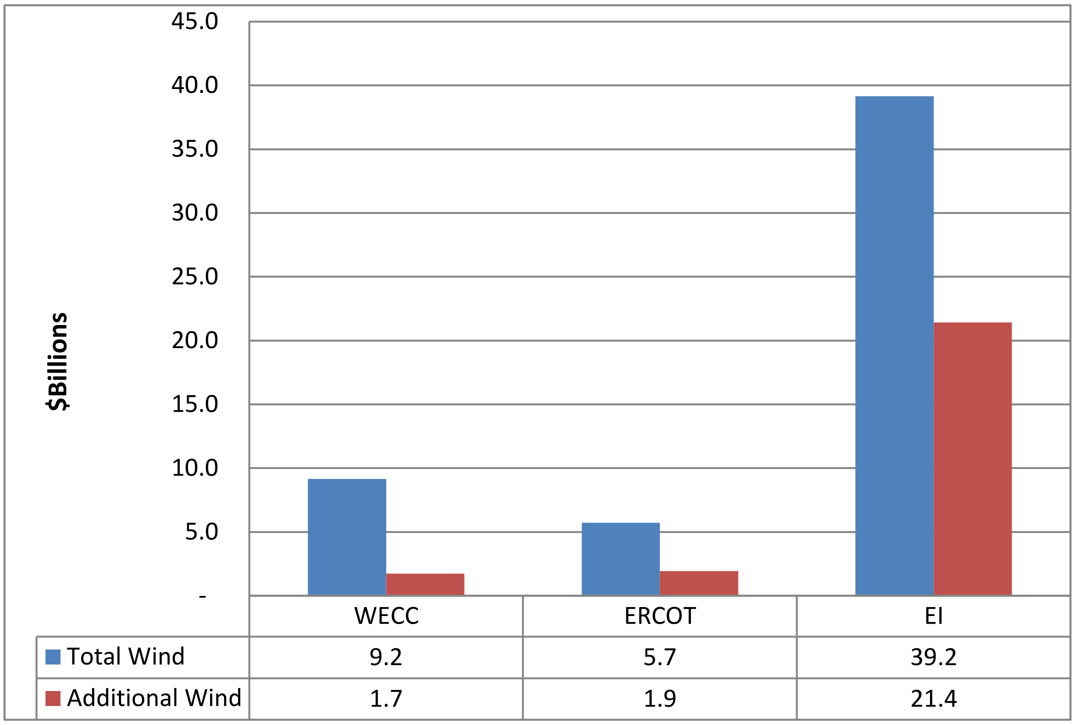


Figure 6.6. Total Life-cycle Costs for Case 2: Na-S Batteries plus Combined Cycle Plants - WECC, ERCOT, and EI (Total and Additional Wind Scenarios).

Drilling down to the sub-region level, Table 6.5and Figure 6.7 present the detailed case-by-case results for the NWPP. In nearly all cases, the costs associated with the energy storage options are lower than those estimated for the CT case (Case 1), particularly with respect to fuel and emissions costs, and the NWPP is no exception. Using 2020 price forecasts, Case 1, combustion turbines, is the 7th most cost-effective alternative, less costly than only Case 5, CAES and CC plants, and Case 8, PH with two mode changes. Under the scenarios explored in this report, capital costs drive the outcome, and the CT and PH cases with their corresponding high capital costs do not perform well. Both options appear ill-suited for providing balancing services alone. For example, PH with its large reservoir is underutilized in this analysis.

Table 6.5. Economic Analysis Results for NWPP (in Million 2011 Dollars)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	5,175	1,067	454	422	**7,117**
2	2,316	164	304	65	**2,849**
3	3,884	147	277	58	**4,366**
4	2,635	70	592	28	**3,324**
5	6,332	1,478	903	584	**9,298**
6	5,629	190	272	75	**6,166**
7	6,334	144	281	57	**6,817**
8	11,550	646	776	255	**13,227**
9	6,891	-	-	-	**6,891**

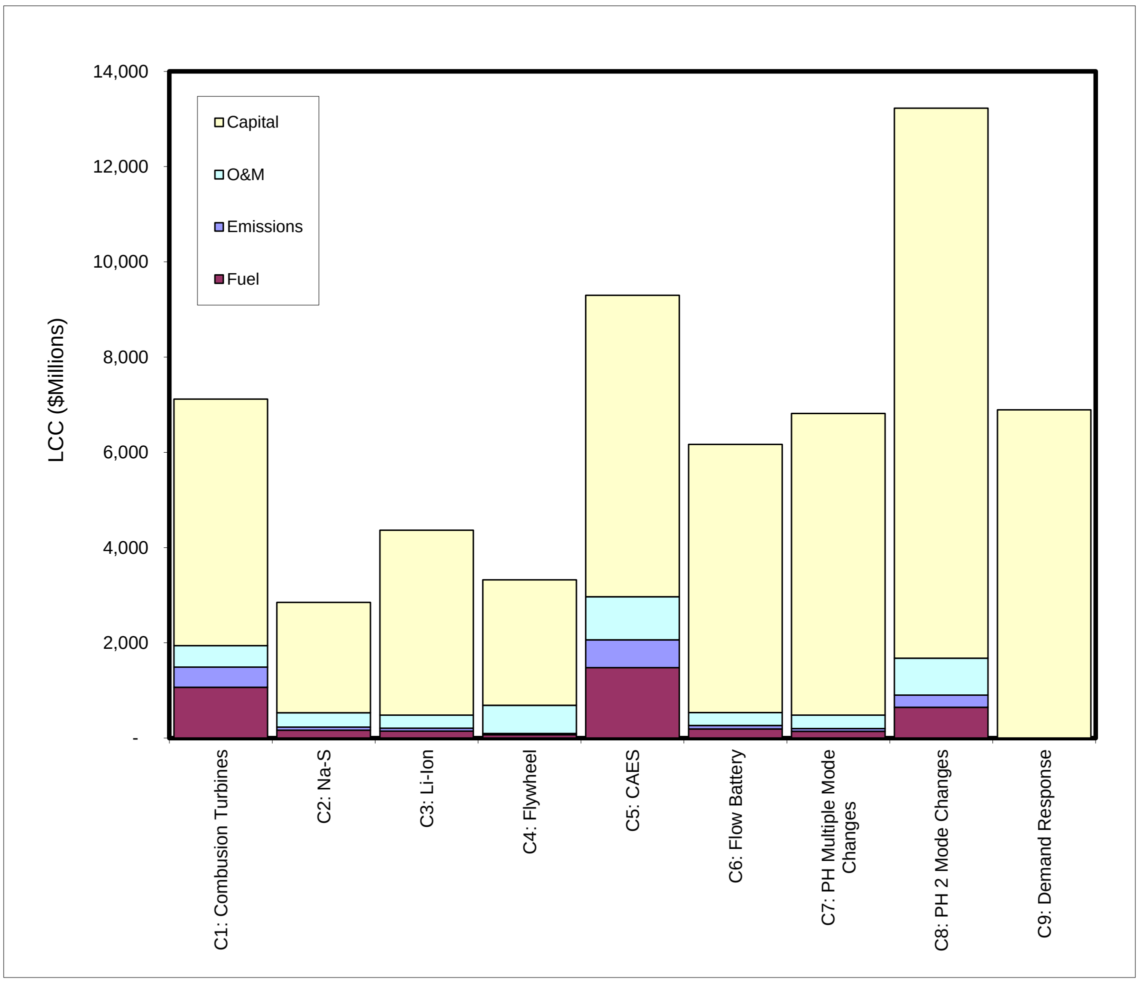


Figure 6.7. Scenario LCC Estimates for NWPP

The results of this analysis, which support the application of energy storage technologies for balancing services, could lead the reader to question why these technologies have not yet been deployed on a broader scale. While the results of this analysis suggest perhaps that they should be deployed more broadly, there are technical and financial barriers worth discussing.

The first hurdle to broader deployment is tied to technical limitations and inexperience in using energy storage technologies for balancing and other ancillary services. The small number of non-hydro installations highlighted in Table 1.1, while certain to provide useful technical information for utilities considering adoption of energy storage, does not constitute a proven track record sufficient to demonstrate the feasibility of implementation on a broader scale. Furthermore, recent installations have presented technical challenges resulting in significant one-time engineering time and cost that were not considered in the LCC analysis.

There is also a significant degree of cost uncertainty associated with the energy storage technologies considered in this study. Project information and literature reviewed for this study present a wide range of costs for Na-S, Li-ion, and redox flow batteries, as well as flywheels and CAES. In some cases, capital costs varied significantly, resulting in LCC variability of up to 48%. Table 6.6 presents low- and high-end cost estimates for each of the technologies examined in this study for the year 2020 and Figure 6.8 presents the effects of capital cost variation on the total LCC for each case.

Table 6.6. Capital Cost Range for Various Technologies in Year 2020

Technology	\$/kWh	\$/kW
Sodium sulfur	181-331	
Lithium-ion	290-700	
Pumped Hydro	10	1,640-2,400
Combustion Turbine		990
Demand Response		620
Compressed Air	3	500-1,140
Flywheels	81-148	200-820
Redox Flow Battery	88-173	608-942

The technical and cost uncertainty regarding energy storage technologies is further evaluated in the TRLs and MRLs assigned to each and presented in Table 3.1. TRLs assigned to the energy storage technologies are as low as six for redox flow batteries and seven for Na-S batteries, Li-ion batteries, and flywheels. A TRL of six indicates that a prototype system has been verified while a TRL of seven indicates that an integrated pilot system has been demonstrated. Conversely, CT received a TRL of nine, which indicates that the system is proven and ready for full commercial deployment. The MRL for flywheels and redox flow batteries is five indicating that the manufacturing process is under development. Na-S and Li-ion batteries received MRLs of six indicating that a critical manufacturing process for utility-scale systems has been prototyped. CT received an MRL rating of 10 indicating that full rate production has been demonstrated and lean production practices are in place.

The nascent state of deployment in which most of these energy storage technologies currently are combined with the corresponding technical and cost uncertainty could present problems from the standpoint of regulatory recovery and financing costs. If these investments were undertaken using project-level financing and cost uncertainty drove up borrowing costs by 200 basis points, or 2%, the LCC for Case 3 (Li-ion batteries and CC power plants) would increase by 21.5% from \$4.4 billion to \$5.3 billion in the NWPP. However, the impact would be more likely to be indirect as utilities perform investment planning that effects their overall creditworthiness and ability to make a rate case to utility commissions.

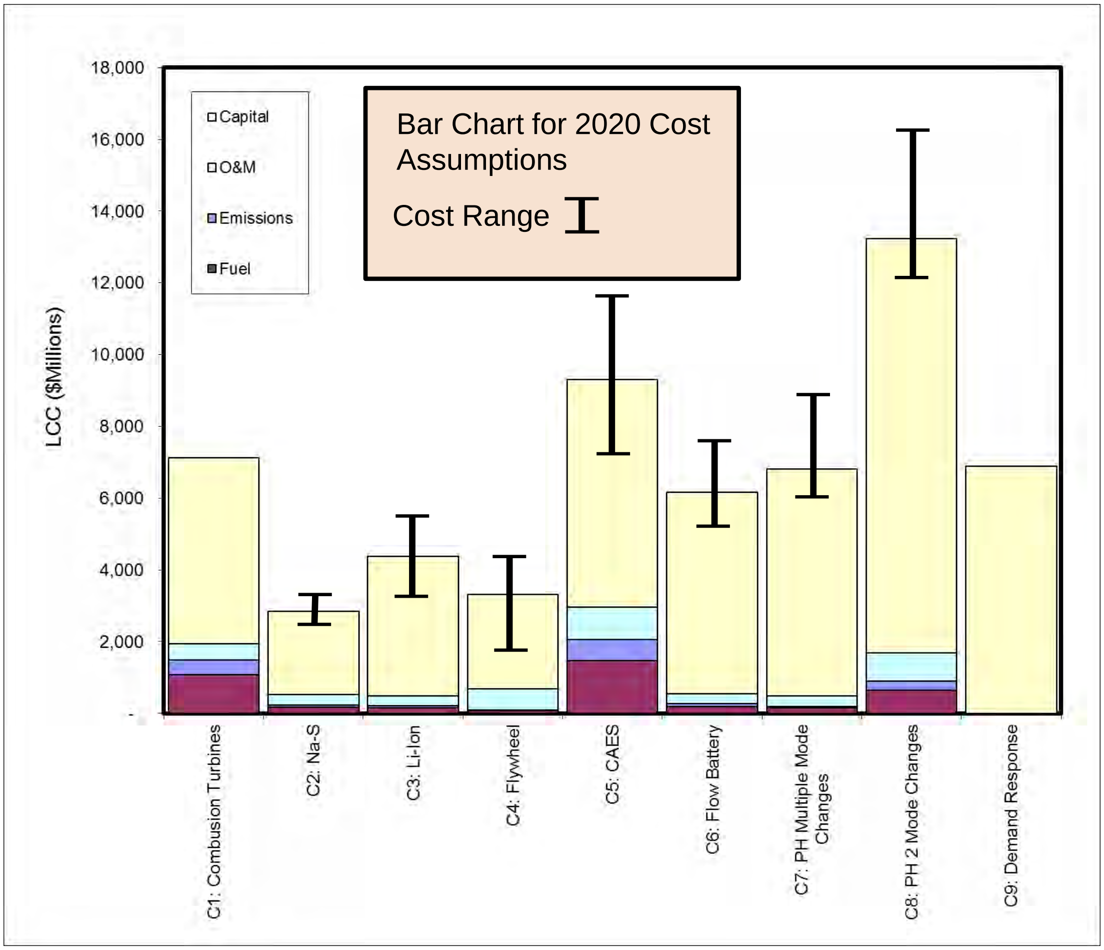


Figure 6.8. LCC Estimates Adjusted due to Capital Cost Variability

6.5 Sensitivity Analysis

To explore the sensitivity of the results to varying a small number of key assumptions, the research team conducted a series of sensitivity analyses. Sensitivity analysis was performed by making the following adjustments to the assumptions underlying the results:

SA 1. Use prices for each technology estimated for 2011

SA 2. Vary the discount rate between 6% and 10%

SA 3. Increase the annual capital cost escalation rate to 3%

SA 4. Increase the annual fuel price escalation rate to 5%

SA 5. Vary the capital cost assumptions using the low- and high-end of the cost range for each technology presented in Table 6.7.

Table 6.7 presents the results of the five sensitivity analyses as compared to the base case for the NWPP. Note that both the second and fifth sensitivity analyses, which respectively adjust discount rates and capital cost assumptions, evaluate two alternative assumptions.

Table 6.7. Sensitivity Analysis Results

Case	Base Case	SA 1	SA 2 (6% discount rate)	SA 2 (10% discount rate)	SA3	SA 4	SA 5 (Low)	SA 5 (High)
1	7,117	7,216	9,067	5,986	7,787	7,539	7,117	7,117
2	2,849	3,916	3,489	2,469	3,096	2,914	2,252	3,074
3	4,366	7,781	5,495	3,691	4,909	4,424	3,003	5,542
4	3,324	6,029	3,897	2,984	3,500	3,351	1,723	4,162
5	9,298	10,574	11,208	8,204	9,708	9,882	6,926	11,247
6	6,166	8,969	7,627	5,291	6,856	6,241	4,961	7,367
7	6,817	6,601	7,125	6,656	6,853	6,874	5,989	8,547
8	13,227	12,608	14,022	12,790	13,253	13,482	11,777	16,390
9	6,891	6,891	8,974	5,571	6,891	6,891	6,891	6,891

In the first sensitivity analysis case, current technology prices were used. The underlying assumption governing this first case is that prices remain unchanged over the next nine years and the cost adjustments forecast in the 2020 base case are never realized. The capital cost forecasts for CT, CC plants and PH were taken from the AEO 2011 reference case, which includes forecast costs out to 2035 (DOE/EIA 2011). The costs for these technologies are forecast to grow over the next 5-6 years because construction costs for all plant types have risen significantly in recent years. This cost growth is forecast based on a commodity cost index that was implemented for the AEO. Growth in the cost index is tied to rising commodity prices, such as steel, copper, cement, and other construction materials. In the long run, the commodity prices do decline and technology growth leads to cost reductions in the latter years of the forecast.

Battery and flywheel costs used in the base case ($510 per kWh for Li-ion, $290 per kWh for Na-S, $133/kWh and $775/kW for redox flow battery, and $115/kWh and $610/kW for flywheel) reflect significant cost reductions forecast over the 2011 to 2020 time period. When using current cost data for these energy storage technologies, costs increase to $1,000 per kWh for Li-ion, $415 per kWh for Na-S, $215 per kWh and $1,111 per kW for redox flow batteries, and $148 per kWh and $1,277 per kW for flywheels.

Due to the forecasts underlying the base case, which include cost reductions for battery technologies, using current prices makes scenarios involving CT, PH, and DR relatively more cost efficient. For example, PH with multiple mode changes (Case 7) is much more cost-competitive when using 2011 prices with estimated costs dropping to $6.6 billion. However, the results of Sensitivity Analysis 1 continue to show Case 2 as the most cost-effective, though costs under this scenario increase significantly from $2.8 billion to $3.9 billion.

The discount rate was varied in SA 2 from the 8% used in the base case to 6% and 10%. By reducing the discount rate, the present value of the interim capital costs associated with battery replacement in the out years of the 50-year analysis time horizon are increased. When the discount rate is reduced, the PH scenarios become relatively more cost efficient because the asset is long-lived (50 years) and does not require interim capital costs. Reducing the discount rate to 6% increases the costs associated with Case 2 significantly (Na-S batteries) from $2.8 billion to $3.5 billion (22.4%). For Case 7 (Na-S batteries plus PH with frequent mode changes per day), however, the impact is minimal with costs increasing by 4.5% from $6.8 billion to $7.1 billion. Using the higher discount rate of 10% conversely favors battery technologies with large interim capital costs.

The third and fourth sensitivity analyses, which include variability with respect to cost inflation for capital and fuel costs, with minor exceptions do not appear to lead to a re-ordering of the most cost efficient options. Thus, results do not appear to be very sensitive to varying capital cost and fuel price inflation rates.

The final sensitivity analysis, which examines the impacts of varying the capital cost assumptions presented in Table 6.7, demonstrates that some cases have more variability or uncertainty than others. More specifically, the cost variance is far greater among the less mature energy storage technologies, including Na-S, Li-ion, and redox flow batteries, as well as flywheels and CAES. For these technologies, the projects and literature reviewed for this study demonstrates that costs could vary significantly. For example, using the upper bound of the Li-ion capital cost range would increase total costs for Case 3 by 27%. Using the lower bound of the flywheel capital cost range, on the other hand, would reduce the total costs associated with Case 4 by 48%. The range of plausible capital costs is much smaller for more mature technologies, including CT, CC plants, and PH.

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