Arnold Schwarzenegger
Governor

AN ASSESSMENT OF BATTERY AND HYDROGEN ENERGY STORAGE SYSTEMS INTEGRATED WITH WIND ENERGY RESOURCES IN CALIFORNIA

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies

An Assessment of Battery and Hydrogen Energy Storage Systems Integrated with Wind Energy Resources in California is the final report for the Environmental Impacts and Economic Potential of Novel Hydrogen-Renewable Infrastructure project (contract number 500-02-004, MR-03-15) conducted by the University of California, Berkeley. This project contributes to the Energy-Related Environmental Research program. Supporting material can be obtained from the Renewable and Appropriate Energy Laboratory, directed by Professor Daniel M. Kammen, at the following Web site: http://socrates.berkeley.edu/~rael.

For more information on the PIER Program, please visit the Energy Commission's Web site at www.energy.ca.gov/pier or contract the Energy Commission at (916) 654-5164.

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Abstract

This exploratory investigation examined energy storage technologies that can potentially enhance the operation of wind power and other intermittent renewable energy systems. We conducted economic and environmental analyses of four energy storage options: (1) lead acid batteries, (2) zinc bromine (flow) batteries, (3) a hydrogen electrolyzer and fuel cell storage system, and (4) a hydrogen storage option where the hydrogen was used for fueling hydrogen-powered vehicles. These were considered under two wind penetration scenarios (2010 and 2020) at four California sites that are likely to experience significant wind farm development.

Analysis with NREL's HOMER model showed that, in most cases, energy storage systems were not well utilized until higher levels of wind penetration were modeled (i.e., 18% penetration in Southern California in 2020). In our scenarios, hydrogen storage became more cost-effective than battery storage at higher levels of wind power production, and using the hydrogen to refuel vehicles was more economically attractive than reconverting the hydrogen to electricity. The overall value proposition for energy storage used in conjunction with intermittent renewable power sources depends on multiple factors. Our initial qualitative assessment found the various energy storage systems to be environmentally benign, except for emissions from the manufacture of some battery materials.

Executive Summary

California's renewable portfolio standard (RPS) requires the state's electricity generating companies to produce or purchase 20% of the electricity they sell from renewable technologies by 2017.[1] In September 2003, the Energy Commission took that vision a step further and recommended that the goal be met by 2010.[2] More recently, in support of a policy goal advocated by Governor Schwarzenegger, the Energy Commission suggested pursuing a goal of 33% renewable electricity by 2020 to maintain rather than reduce the rate of renewable energy development in California from 2010 to 2020.[3]

Technologies such as wind turbines and solar photovoltaics are poised to contribute substantially in meeting this goal; however, the widespread acceptance and use of these technologies is hindered by their inability to provide power when the wind is not blowing or the sun is not shining. To help these intermittent renewable technologies become more competitive with fossil and hydroelectric power plants, their output can be stabilized with the use of energy storage systems, which would allow electricity to be produced at times of relatively low economic value and stored so that it can be dispatched at a later time. However, energy storage entails varying economic costs and environmental impacts depending on the specific location and type of generation involved, the energy storage technology used, and the other potential benefits that energy storage systems can provide (e.g., helping to optimize transmission and distribution systems, local power quality support, potential provision of spinning reserves and grid frequency regulation, etc.).

In order to investigate the potential benefits of various advanced energy storage systems in a future California context, the PIER-EA Exploratory Grant Program funded the University of California, Berkeley (UC Berkeley) to conduct a scooping study on the economics and environmental impacts of battery, hydrogen-based, and other advanced energy storage technologies. UC Berkeley researchers reviewed three types of battery technologies (conventional lead acid, advanced zinc bromine, and vanadium redox); hydrogen production, storage, and re-conversion to electricity; hydrogen production, storage, and sale to hydrogen-powered vehicles; compressed air energy storage, pumped hydro energy storage; mechanical flywheels; and superconducting magnetic energy storage. Of these, two battery and both hydrogen systems were analyzed in detail, based on the capabilities of the modeling platform used for the detailed analysis.

The researchers identified four sites in California that are likely to experience significant growth in renewable wind power generation under the statewide RPS and performed economic and environmental analyses of energy storage in the context of those sites. These sites were Altamont Pass and Solano County in Northern California, and Tehachapi and San Gorgonio

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1. SB 1078, Sher, Chapter 516, Statutes of 2002.

2. California Energy Commission (2003c), *Integrated Energy Policy Report, 2003 Update,* Report 100-03-019F, December.

3. California Energy Commission (2004a), *Integrated Energy Policy Report, 2004 Update,* Report 100-04-006CM, November.

passes in Southern California. Two time frames were considered: 2010, with 10% statewide wind power penetration, and 2020, with 20% statewide wind penetration. Based on present and future projected wind resources in the two halves of the state, wind penetration levels were assumed to be 1% in Northern California and 9% in Southern California (2010) and 2% in Northern California and 18% in Southern California (2020).

To perform these analyses, researchers used the HOMER model developed by the National Renewable Energy Laboratory (NREL). The model was modified to include hour-by-hour characterizations of the four California wind sites and additional input data to characterize hydrogen production and storage systems and lead acid battery and zinc-bromine flow battery storage systems.

Key Assumptions

Key assumptions guiding this analysis include the following:

- Wind power will expand in California under the statewide RPS program to a level of approximately 10% of total energy provided in 2010 and 20% by 2020, with most of this expansion in Southern California.
- Costs of flow battery systems are assumed to decline somewhat through 2020 and costs of hydrogen technologies (electrolyzers, fuel cell systems, and storage systems) are assumed to decline significantly through 2020.
- In the case where hydrogen is produced, stored, and then reconverted to electricity using fuel cell systems, we assume that the hydrogen can be safely stored in modified wind turbine towers at relatively low pressure at lower costs than more conventional and higher-pressure storage.
- In the case where hydrogen is produced and sold into transportation markets, we assume that there is demand for hydrogen for vehicles in 2010 and 2020, and that the hydrogen is produced at the refueling station using the electricity produced from wind farms (in other words, we assume that transmission capacity is available for this when needed).

Key Project Findings

Key findings from the HOMER model projections and analysis include the following:

- Energy storage systems deployed in the context of greater wind power development were not particularly well utilized (based on the availability of "excess" off-peak electricity from wind power), especially in the 2010 time frame (which assumed 10% wind penetration statewide), but were better utilized–up to 1,600 hours of operation per year in some cases–with the greater (20%) wind penetration levels assumed for 2020.
- The levelized costs of electricity from these energy storage systems ranged from a low of $0.41 per kWh—or near the marginal cost of generation during peak demand times—to many dollars per kWh (in cases where the storage was not well utilized). This suggests that in order for these systems to be economically attractive, it may be necessary to optimize their output to coincide with peak demand periods, and to identify additional

value streams from their use (e.g., transmission and distribution system optimization, provision of power quality and grid ancillary services, etc.).

- At low levels of wind penetration (1%–2%), the electrolyzer/fuel cell system was either inoperable or uneconomical (i.e., either no electricity was supplied by the energy storage system or the electricity provided carried a high cost per MWh).
- In the 2010 scenarios, the flow battery system delivered the lowest cost per energy stored and delivered.
- At higher levels of wind penetration, the hydrogen storage systems became more economical such that with the wind penetration levels in 2020 (18% from Southern California), the hydrogen systems delivered the least costly energy storage.
- Projected decreases in capital costs and maintenance requirements along with a more durable fuel cell allowed the electrolyzer/fuel cell to gain a significant cost advantage over the battery systems in 2020.
- Sizing the electrolyzer/fuel cell system to match the flow battery system's relatively high instantaneous power output was found to increase the competitiveness of this system in low energy storage scenarios (2010 and Northern California in 2020), but in scenarios with higher levels of energy storage (Southern California in 2020), the electrolyzer/fuel cell system sized to match the flow battery output became less competitive.
- In our scenarios, the hydrogen production case was more economical than the electrolyzer/fuel cell case with the same amount of electricity consumed (i.e., hydrogen production delivered greater revenue from hydrogen sales than the electrolyzer/fuel cell avoided the cost of electricity, once the process efficiencies are considered).
- Furthermore, the hydrogen production system with a higher-capacity power converter and electrolyzer (sized to match the flow battery converter) was more cost-effective than the lower-capacity system that was sized to match the output of the solid-state battery. This is due to economies of scale found to produce lower-cost hydrogen in all cases.
- In general, the energy storage systems themselves are fairly benign from an environmental perspective, with the exception of emissions from the manufacture of certain components (such as nickel, lead, cadmium, and vanadium for batteries). This is particularly true outside of the U.S., where battery plant emissions are less tightly controlled and potential contamination from improper disposal of these and other materials is more likely.

The overall value proposition for energy storage systems used in conjunction with intermittent renewable energy systems depends on diverse factors:

- The interaction of generation and storage system characteristics and grid and energy resource conditions at a particular location
- The potential use of energy storage for multiple purposes in addition to improving the dependability of intermittent renewables (e.g., peak/off-peak power price arbitrage, helping to optimize the transmission and distribution infrastructure, load-leveling the grid in general, helping to mitigate power quality issues, etc.)

- The degree of future progress in improving forecasting techniques and reducing prediction errors for intermittent renewable energy systems
- Electricity market design and rules for compensating renewable energy systems for their output

Conclusions

This study was intended to compare the characteristics of several technologies for providing energy storage for utility grids—in a general sense and also specifically for battery and hydrogen storage systems—in the context of greater wind power development in California. While more detailed site-specific studies will be required to draw firm conclusions, we believe that energy storage systems have relatively limited application potential at present but may become of greater interest over the next several years, particularly for California and other areas that are experiencing significant growth in wind power and other intermittent renewables.

Based on this study and others in the technical literature, we see a larger potential need for energy storage system services in the 2015–2020 time frame, when growth in renewables-produced electricity is expected to reach levels of 20%–30% of electrical energy supplied. Depending on the success in improved wind forecasting techniques and electricity market designs, the role for energy storage in the modern electricity grids of the future may be significant. We suggest further and more comprehensive assessments of multiple energy storage technologies for comparison purposes, and additional site- and technology-specific project assessments to gain a better sense of the actual value propositions for these technologies in the California energy system.

PIER Program Objectives and Potential Benefits for California

This project has helped to meet PIER program objectives and to benefit California in the following ways:

- **Providing environmentally sound electricity.** Energy storage systems have the potential to make environmentally attractive renewable energy systems more competitive by improving their performance and mitigating some of the technical issues associated with renewable energy/utility grid integration. This project has identified the potential costs associated with the use of various energy storage technologies as a step toward understanding the overall value proposition for energy storage as a means to help enable further development of wind power (and potentially other intermittent renewable resources as well).
- **Providing reliable electricity.** The integration of energy storage with renewable energy resources can help to maintain grid stability and adequate reserve margins, thereby contributing to the overall reliability of the electricity grid. This study identified the potential costs of integrating various types of energy storage with wind power, against which the value of greater reliability can be assessed along with other potential benefits.
- **Providing affordable electricity.** Upward pressure on natural gas prices, partly as a function of increased demand, has significantly contributed to higher electricity prices in California and other states. Diversification of electricity supplies with relatively low-cost sources, such as wind power, can provide a hedge against further natural gas price

increases. Higher penetration of these other (non-natural-gas-based) electricity sources, potentially enabled by the use of energy storage, can reduce the risks of future electricity price increases.

1.0 Introduction and Project Overview

Renewable energy resources such as wind and solar power, biomass, and hydropower have the advantages of being sustainable and relatively benign in terms of impacts on environmental and human health. Historically these resources have been relatively high cost, but advances over the past few decades have made some renewable resources much more competitive. For example, the levelized costs of wind power have fallen from approximately $0.30–$0.40 per kWh in 1980 to only $0.03–$0.05 per kWh today at good sites,[4] with projections of costs as low as $0.02 per kWh at particularly attractive sites by 2015 (Short 2002).

However, a significant disadvantage of some renewable energy resources is that they are intermittent, with considerable variability in supply in most settings. For example, one can predict that the solar photovoltaic resource will generally be available during the daylight hours, and use historical observations to suggest likely seasonal and daily patterns of wind power resource availability. On an hour-by-hour or minute-by-minute basis, however, cloud cover can diminish the solar resource, and wind speeds can affect the availability of wind power. These types of renewable resources, therefore, pose a challenge for resource forecasting and scheduling, and are generally less "dispatchable" to utility grids than other types of generation that are "firmer"[5] (such as conventional fossil fuel–powered generation).

Intermittent renewable resources that are integrated into utility-scale electricity transmission and distribution infrastructure have historically participated in electricity markets under contract rules that penalized them for failing to provide power when predicted (and also, in some cases, not fully compensating them for production in excess of predictions). Under certain circumstances (including rules currently being considered for the California market), intermittent renewables may be given relatively favorable contracting terms as an incentive measure, provided that some of the complications and expenses of incorporating intermittent renewables into utility grids are addressed.

As it stands, however, a key barrier to building more renewable energy systems in California is their intermittent nature and the forecasting errors for bidding their energy services into energy markets. Adding energy storage systems or backup generators near these systems to firm up their output, so that they can provide power under contracts that more fully compensate them for the power that they provide, could improve their economics.

Moreover, practical energy storage systems could alleviate power quality issues that could interfere with connecting wind turbines to the grid. In addition to local power quality support,

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4. By "good sites" we mean Class 4–6 wind sites. Class 4 wind sites have average wind speeds of 5.6–6.0 meters per second (18.4–19.7 feet per second), Class 5 wind sites have average wind speeds of 6.0–6.4 meters per second (19.7– 21 feet per second), and Class 6 wind sites have average wind speeds of 6.4–7.0 meters per second (21–23 feet per second), measured at a height of 10 meters (33 feet) above ground level.

5. Electricity generation resources are considered "firm" when they can be readily dispatched when called upon. Intermittent resources such as wind power are not firm in most settings, because their output varies with meteorological conditions.

energy storage systems can provide other grid support benefits such spinning reserve[6] and frequency regulation[7] services, etc.). This could aid further development of renewable energy resources to diversify California's electricity feedstock base in ways that will help to reduce dependence on fossil fuels and insulate consumers against natural gas and electricity price swings.

This report explores and analyzes in a relatively broad sense the potential role of energy storage systems to be deployed in conjunction with one type of renewable resource in California—wind power—that is expected to experience increased deployment in the coming years and decades. Our goal is to explore the relative costs of various energy storage systems in the context of wind power development in different parts of California in the 2010 and 2020 time frames.

We explicitly do not endeavor to determine the optimal amount of energy storage on a local or statewide basis. Such an assessment would require analysis at a finer resolution and in a more comprehensive manner than we undertake here, and it would also depend on a series of future events and conditions that are difficult to predict. Rather, we attempt to assess the general extent to which energy storage might be utilized in the context of four promising sites for further wind power development in California. We also analyze in detail the relative costs associated with the battery and hydrogen electrolyzer/fuel cell storage systems. Additionally, we partially analyze the benefits of integrating these energy storage systems with projected future wind power developments.

1.1. Research Goals and Objectives

The primary objective of this exploratory research project was to assess the relative costs and benefits of various options for energy storage for intermittent renewable electricity generating systems in California, including hydrogen-based storage systems. This initial assessment will be useful in gaining an early sense of the prospects for various types of renewable energy "buffer storage" systems in the California context.

The specific goals of this analysis were as follows:

- Explore the relative costs and benefits of battery and hydrogen-based energy storage systems in the context of wind power development in various parts of California in the 2010 and 2020 time frames
- Gain a sense of the degree to which these energy storage systems would potentially be utilized, based on varying wind power penetration levels for 2010 and 2020 and different potential wind development regions
- Compare the economics of hydrogen stored and converted back to electricity versus hydrogen produced for sale to hydrogen-powered vehicles

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6. *Spinning reserves* are power generation resources that are synchronized with the grid, ready for immediate power generation if needed to meet supply shortfalls.

7. Grid *frequency regulation* involves adding or subtracting power from generators to maintain the grid frequency near a specific level—typically 60 cycles per second (or "Hertz") in the U.S.

- Conduct a broader qualitative assessment (including an environmental assessment) of the energy storage systems that are analyzed in detail along with other potential storage systems (e.g., pumped hydro and compressed air energy storage)

In addition to the cost assessment conducted here, we also partially analyzed the benefits of integrating these energy storage systems with projected future wind power developments. However, we did not completely analyze these potential benefits because the total benefits would be highly context- and location-specific and would require a more detailed analysis. These potential benefits include improving the dispatchability characteristics (and thus marketability) of intermittent renewables, maximizing the potential output of intermittent renewables, mitigating some of the technical issues associated with integrating intermittent renewables with utility grids, and reducing the amount of transmission capacity that is needed to fully access renewable resource output. Also, under some market structures, energy storage could be used to shift renewable energy production from times of relatively low value to high-value periods, thereby improving the overall economics of these systems.

1.2. Project Methodology

In conducting this project, we first surveyed the latest information on cost, performance, and life cycle environmental impacts of several known electricity storage and hydrogen production technologies. These include conventional lead acid batteries, advanced flow (zinc bromine and vanadium redox) batteries, hydrogen production and reuse with electrolyzer/fuel cell technology, compressed air energy storage, pumped hydro energy storage, flywheels, and superconducting magnetic energy storage. Second, we conducted modeling and analysis using the National Renewable Energy Laboratory's HOMER model, comparing battery and hydrogen energy storage systems as coupled with wind energy at four California locations. Third, we analyzed environmental aspects of storage systems for wind energy. Finally, we considered additional wind and utility grid integration issues and drew conclusions.

With regard to the modeling aspect of the project, we considered four potential sites within California that are suitable for either significantly expanded wind power or solar PV power generation. Two of these are in Northern California (Solano and Altamont) and two are in Southern California (San Gorgonio and Tehachapi). At each of these sites, using the National Renewable Energy Laboratory's HOMER model, we analyzed and compared the potential use of hydrogen energy storage technologies with conventional (lead acid) and "flow" (zinc bromine) battery systems. We examined cases where excess wind energy from Southern California sites could be exported to Northern California through Path 15[8] and vice versa, as well as "transmission constrained" cases where these transfers were not possible. We also examined various economic assumptions by conducting "Year 2010" and "Year 2020" analysis scenarios. The 2020 scenarios included projections of energy storage and wind system capital costs that were lower than the 2010 scenarios, as well as a greater degree of wind power penetration in California.

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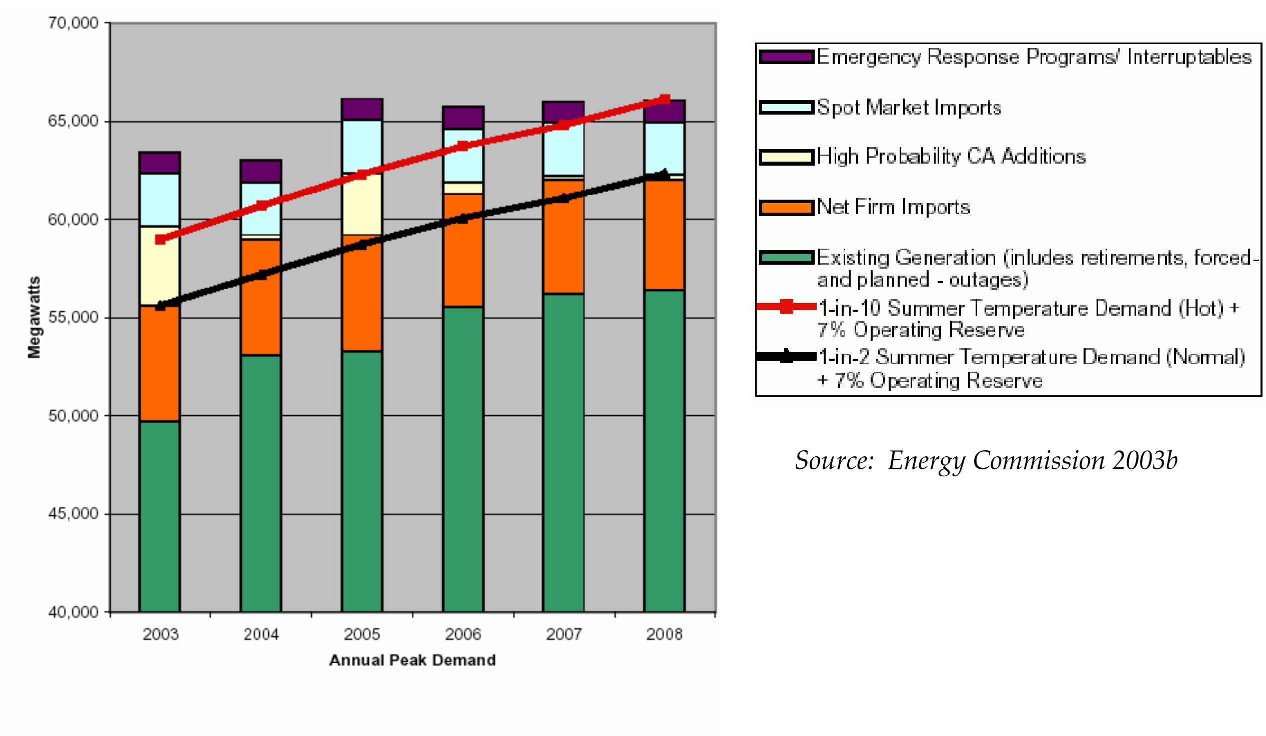
8. *Path 15* is the major electricity transmission pathway between Northern and Southern California. It is 84 miles long and located in the Central Valley. Path 15 has recently been expanded to add a third 500-kilovolt transmission line, raising the transmission capacity to 5,400 MW in the northward direction.

2.0 Background

2.1. California's Renewable Portfolio Standard Program

California currently relies on natural gas for the generation of about 36% of its power, coal for 20%, large hydro for 18%, nuclear for 15%, geothermal for 5%, and solar, wind, small hydro, and other renewable sources for about 6% (Energy Commission 2003a). Figure 1 shows that the state's electricity supply is expected to tighten in the coming years, despite increases in generating capacity, due to steady increases in forecasted demand. The issue of adequate reserve margins is particularly severe in Southern California, where the latest projections show that even under favorable conditions, reserve margins are likely to fall to around 2% by 2007, with significant shortfalls in extreme (1 in 10) cases of up to 6% with anticipated power plant retirements and as much as 30% with higher-than-expected power plant retirements (Energy Commission 2004a). These projections are somewhat alarming and have prompted the California Public Utilities Commission and the Energy Commission to carefully examine the issue of aging power plants and possible further expansion of transmission capacity from Northern to Southern California.



Source: Energy Commission 2003b

Figure 1. Five-year California electricity supply forecast

In order to meet the growth in electricity demands in a way that is compatible with California's environment, the state legislated a renewable portfolio standard (RPS) with the passage of Senate Bill 1078 in 2002. This RPS calls for investor-owned utilities to steadily increase the amount of renewable energy that they purchase. The increase required by the RPS is from the present level of 11%–12% to 20% by 2017. However, in its 2003 *Integrated Energy Policy Report*, the Energy Commission recommended accelerating this goal to achieve the 20% renewables level by 2010 (Energy Commission 2003c). Governor Schwarzenegger publicly supported this accelerated RPS goal and indicated support for a 33% renewables level by 2020—a policy goal that the Energy Commission supported in the 2004 update of the *Integrated Energy Policy Report* (Energy Commission 2004a). Since wind energy is a relatively low-cost form of renewable electricity production, the RPS measure is expected to lead to significant increases in wind energy development in California, along with solar, biomass, and other renewable energy sources.

Greater use of renewable energy systems, as called for in the state RPS program, can help to reduce the state's reliance on natural gas for electricity generation, and therefore can help to insulate consumers against spikes in natural gas prices. While renewable energy systems are often more expensive than conventional natural gas power plants when gas prices are low, renewables may be more competitive when natural gas prices are higher—which is quite possible in the future. Moreover, renewables have the advantage of offering more stable (less variable) costs and benefits over time.

2.2. Wind Energy in California's Future

California currently has about 1.6 GW of installed wind power capacity that produces over 3,500 GWh of electricity every year. Significant increases are expected over the next several years. Even relatively conservative estimates for the technical potential in wind power development in California show that over 14 GW of wind power development is possible in high-wind-speed sites alone. Adding low-wind-speed sites brings the technical potential of wind power in California to nearly 100 GW (Energy Commission 2003d).

Wind power is relatively inexpensive among renewable electricity alternatives, making it an attractive target for helping to meet the goals of the state RPS. However, wind power also has its drawbacks:

- Wind machines are limited to locations with strong, dependable winds.
- Wind power is intermittent, meaning that backup generation or energy storage may be needed to "firm up" wind power capacity (when it reaches significant levels of penetration).
- Wind turbine technologies vary in the quality of the power produced, which can cause difficulties in linking certain types of wind turbines to a utility system.
- Wind farms in remote areas may face transmission constraints, necessitating costly transmission system upgrades as wind power is expanded.
- Fair and appropriate procedures and rules must be developed for predicting wind power output and compensating wind power producers for their contributions.
- Wind towers and turbine blades are subject to damage from high winds and lighting.
- The noise made by rotating wind turbine blades (especially by smaller, non-utility-scale turbines) can be objectionable.
- The visual aesthetics of wind turbines can be controversial.
- Wind turbines can kill birds and bats that fly into the rotor paths.

Energy storage can mitigate two of these issues—the problems of wind energy intermittency and power quality, as will be discussed in Sections 2.3 and 2.4.

In general, these wide-ranging barriers to wind power development are currently being addressed through various efforts by the Energy Commission, the California Independent System Operator (CAISO), the California Public Utilities Commission (CPUC), the California Wind Energy Collaborative (CWEC), and other research organizations.

In order to more carefully assess the economics of wind and other renewable energy in the California context, the CWEC conducted a California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis (CWEC 2004). The CWEC analysis addressed the indirect grid integration costs for eligible renewable generators based on the concept of *electrical load-carrying capacity* (ELCC). The ELCC considers each generator in an electrical system and its probability of being unavailable because of mechanical problems, other malfunctions, or, in cases of intermittent renewables, resource unavailability. The ELCC values can be calculated in a simplified fashion as a function of hourly loss-of-load probability,[9] renewable capacity factor[10] during the peak period (top 10% of load hours of the year), and the variability of the renewable resource. For example, higher values for the ELCC result from a combination of higher capacity factors, lower levels of variability, and higher levels of reliability. Simulations for California resources showed approximate ELCC values of 92% for geothermal, 88% for solar photovoltaics, 26% for wind at Altamont, 31% for wind at San Gorgonio, and 29% for wind at Tehachapi (CWEC 2004).

The renewables integration studies and ELCC calculations for the indirect costs of renewables may form the basis for new contract procedures for compensating the contribution of wind energy to California's electrical grid in the future. In the meantime, the CPUC is in the process of considering rules that would compensate wind energy at the utilities' avoided cost of generation. The proposed contract terms are for renewable energy generators to be compensated with long-term power contracts (10 to 20 years) and for the utilities to accept bids for power delivery at a fixed contract price (Smoots 2004).

Under the proposed scheme, once bids are received, the CPUC would develop a "market price referent" (MPR). This MPR is a proxy for the generating costs of new conventional power plants. The MPR would consider the costs of both baseload and peaker plants. The renewable generators would then be paid the full value of the MPR that is developed, up to their bid price. Any increment in the accepted bid price above the MPR would be covered from a "supplemental energy payments" fund administered by the Energy Commission (Smoots 2004).

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9. The *hourly loss-of-load probability* is the probability in each hour of the year that the available generation capacity falls below the utility load. The sum of the hourly loss-of-load probability values equals the annual *loss-of-load expectation.*

10. The *capacity factor* of an electricity generation resource is its actual output over a given period divided by its theoretical maximum output over that same period. The capacity factor is a broader measure of resource availability than the ELCC, because, unlike the ELCC, the capacity factor does not specifically address the impacts of a generating resource on system reliability.

After receiving bids from renewable generators, utilities would rank-order the bids. The bids would first be ordered by price, and a second ordering would consider integration and transmission costs. Utilities would also be able to consider the dispatchability and curtailability of generation in this second ordering step, as long as they do so in a transparent fashion (Smoots 2004).

Under this scheme, the potential value of energy storage would be somewhat different than under the previous system where intermittent renewable generation was compensated with "intermittent resource" contracts that penalized them for failing to deliver the predicted amount of power. The main value of storage would be to provide additional dispatchability for renewable generation, as well as to improve the profile for renewables-based generation to provide power during peak demand periods. This could improve the rank of intermittent renewables bids relative to those that did not include storage and offered lower levels of dispatchability. Additional benefits could be to lower integration costs by improving power quality, and to lower transmission upgrade costs by storing some of the wind power during transmission-constrained periods (i.e., periods when the wind power resource exceeds the local transmission capacity).

2.3. Grid Impacts of Accommodating Wind Energy Without Storage

Multiple issues are involved in integrating intermittent wind power into electrical grids. These issues can be differentiated as primarily technical or economic/administrative, and by the timescale involved. In general, the issues include the balancing of generation and load, technical interface of individual generators or arrays with the broader utility grid, assurance of adequate reserve capacity on an aggregated control area[11] basis, and market structures for bidding, forecasting, assessing, and compensating the output of different types of generators.

Four timescales are of interest to planners. First, the shortest timescale—on the order of several seconds to 10 minutes—involves the relatively rapid response of generators to changing load conditions. This *regulation timescale* typically requires an automatic generation control (AGC) computer that sends signals to one or more generators (that are synchronized to the grid and thus able to respond quickly) to increase or decrease output in response to short-term load variations to maintain a balanced system. Second, at the next level of resolution, timescales of 10 minutes to several hours entail the need for *load following* of the relatively slow but large-magnitude swings in demand that occur throughout the day. Electricity demands are typically lowest at night and increase throughout the day until the late afternoon or early evening when they begin to decrease. Third, timescales of several hours to several days involve the concept of *unit commitment* where individual generators are committed and started up to meet demands that will occur several hours to days hence (depending on the characteristics of the generators in question) or shut down if they are not needed for the ensuing period. Finally, on the timescale of years, overall power system planning must be undertaken to assure that adequate generation resources are in place to meet growing demands (Parsons et al. 2003; CWEC 2004).

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11. A *control area* is a region defined by an electrical utility or system operator for purposes of balancing generation and load and maintaining system stability.

The potential integration of increased amounts of renewable resources can involve impacts across all of these timescales. At the regulation timescale, rapid movements in renewable resource availability can vary such that the dynamics of balancing generation and load are different with the presence of the renewable resources than they would be without the renewables as part of the mix. We note here, however, that electricity demands (or *loads*) are also variable at this timescale and that there is, therefore, a regulation issue even in the idealized case where all generation is completely predictable and reliable. The addition of intermittent renewables adds additional complexity to the regulation problem, but because the short-term variability in intermittent renewables and loads are unlikely to be correlated, the actual impacts for a specific system generally are not additive and complex to analyze (Parsons et al. 2003).

On the load-following timescale, the addition of increased amounts of renewable generation can affect the economic dispatch of generators. If renewable generation is relatively low cost, it may be favored over other generation sources, thus resulting in a decrease in the contributions demanded from these other resources. The important concept here is the marginal cost of operating various generation sources, their abilities to be dispatched within this timescale, and potential additional considerations such as the impacts on the environmental performance of generators relative to their level of generation. The economic dispatch of generators for load following is specific to a given utility service territory and the generation resources that are available, and is difficult to generalize. However, we note that there are periods in California when the marginal price of electrical power is actually negative, meaning that system operators would in theory pay generators (even relatively low-cost ones) to stay off-line (Hawkins 2004). These periods are infrequent, but there are other periods where the value of power is either negligible or very low.

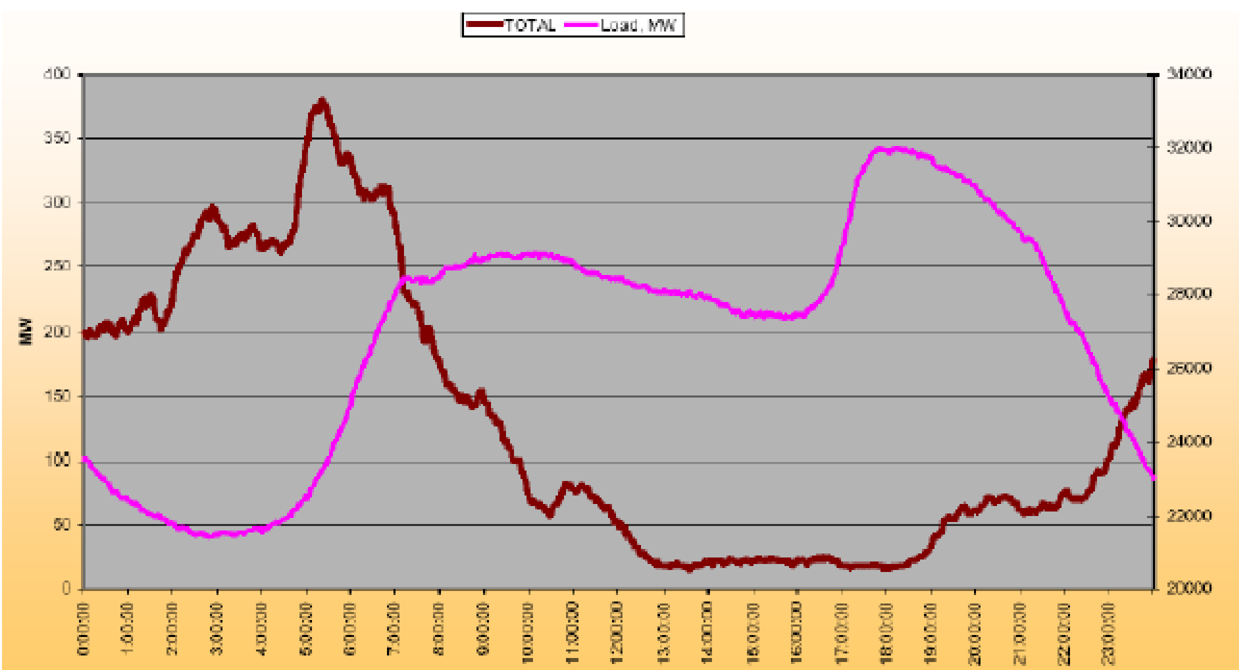
Given that the characteristics of some renewable energy resources (e.g., wind power) in California are such that the availability of the resource does at times occur during these periods, all of the potentially available renewable generation may not be optimally accepted by the system. We elaborate further on this point later in this report and suggest that energy storage systems offer one opportunity for increasing the absolute amount of renewable energy that can be provided to the system, depending on the specific technical and economic characteristics of the available generation mix, the nature of the daily load profiles, and the overall structure of the market.

On the unit commitment timescale, the somewhat unpredictable nature of intermittent renewables complicates the issue of determining which generators should be committed for what periods of time. Forecasts of renewable resource availability are important in this regard, but since these forecasts are imperfect, there are likely to be periods during which generation units are committed that are not needed, and others during which generators are not committed but are later found to have been needed. Improved forecasting techniques can mitigate this issue, and there are considerable efforts under way to improve the quality of renewable resource forecasts and the ability of forecasts to inform the commitment of generation resources. However, these improved forecasting techniques and services also entail costs that must be considered.

2.4. Wind Power Intermittency

A key drawback to wind power is the fact that wind is variable and fluctuates with meteorological conditions in ways that can be difficult to predict. These fluctuations can be characterized as *microscale* (on the order of 10 to 20 seconds) and *mesoscale* (on the order of 30 to 90 minutes), along with longer-term diurnal and seasonal variability. Microscale fluctuations are smoothed to a significant extent across a typical wind power array, but mesoscale fluctuations can be significant for wind farms and even for entire regions. Fluctuations of 10% or more from hour to hour are common for individual wind farms, but the probability of greater fluctuations drops off sharply, such that (in one Danish example) there was only one chance in 10,000 that output could be expected to vary by 30% or more on an hour-to-hour basis (Grubb and Meyer 1993).

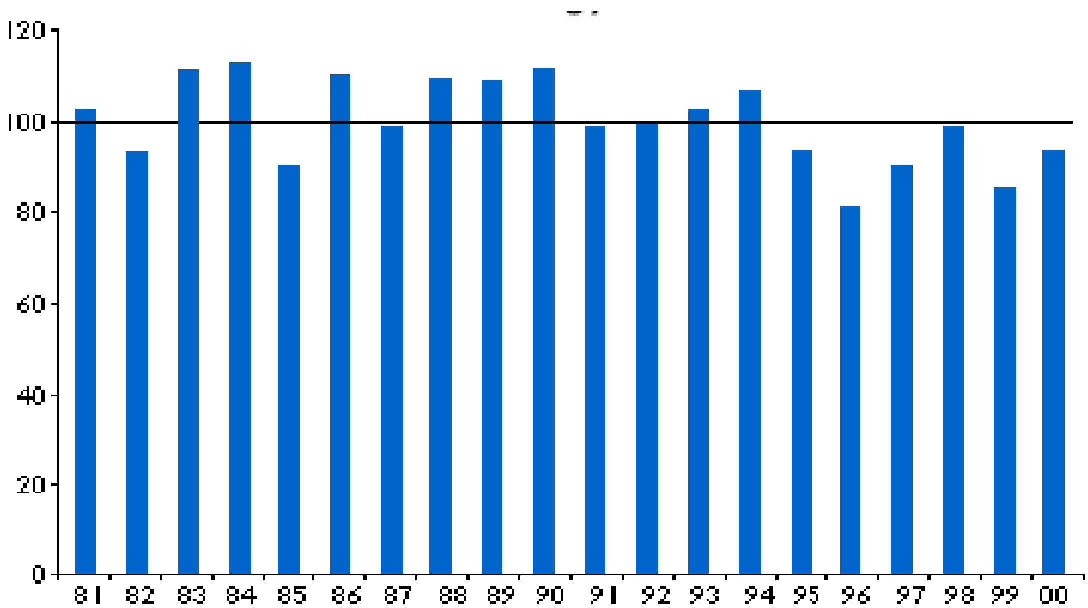
Furthermore, unlike solar power, wind power output does not always (or often in some areas) closely match the diurnal fluctuations in power demand that typically peak in the afternoon hours and are lowest at night. In contrast, in some areas and during some times of the year, wind power can be at or near its peak values at night when grid power demands are relatively low. As an example, Figure 2 presents wind power output on January 6, 2005, as a California average compared with electrical load demand.



Source: Markarov and Hawkins, 2005

Figure 2. Diurnal variation in total wind power output in California versus system load (MW)—January 6, 2005

Wind power also varies seasonally and annually. In temperate areas, the wind resource is often greatest from fall through spring and weakest during the summer. This contrasts with grid peak demands that often are greatest during the summer, particularly in warmer areas that rely on air conditioning. Annual variations in wind power output depend on location, and the output can vary plus or minus 10%–20% from an average baseline. For example, Figure 3 shows the annual variation in wind power in Denmark from 1981 through 2000. As shown in the figure, most years are within 10% of the average level but a few years fall in the 15%–20% range of deviation.



Source: Danish Wind Energy Association 2004a

Figure 3. Annual variation in wind power output in Denmark (normalized)

The short-term variability in wind power output causes problems for electrical grid operators who need to carefully match resources with demands in order to provide adequate safety margins to avoid brownouts and blackouts. The CAISO is currently addressing these issues by developing protocols to better predict wind power output. These efforts are expected to enable grid operators to better balance loads and resources, reduce the needs for ancillary services from other generators, and lower financial risks to both grid and wind farm operators (Abernathy 2002).

The key problem is that wind energy will always differ from predicted output by at least a small amount. These deviations need to be addressed through "imbalance energy costs" whereby wind power is (ideally) compensated for additional output above what was predicted and penalized for output below what was predicted in a way that is fair and that does not shift costs onto other generators. Historically the penalties for under-production have been rather severe, but revised schemes are being devised that are more equitable to wind power producers. In California this is currently being explored through a method that would settle net deviations across all time intervals on a monthly basis, in conjunction with better forecasting techniques (Abernathy 2002).

Energy storage can clearly help with these output variability and imbalance energy cost issues by helping to make wind power output more stable and predictable. With the aid of storage, wind farm operators would be better able to meet their predicted output by storing power that exceeds the predicted output and adding power from the storage system when wind power output falls below predictions.

Better forecasting methods and improved design of future utility grids can help to mitigate the problem of wind power variability in the future. On one hand, greater penetration levels of wind power will worsen the problem, but better forecasting techniques and grid designs should help to reduce the negative impacts of these fluctuations. Studies have generally shown that backup generation or storage requirements of 1%–3% of wind power capacity are typically adequate for wind penetration levels of 5% (on an energy basis) and 3%–8% for wind penetration levels of 15% (Milborrow 2004a; Utility Wind Interest Group 2003).

2.5. Wind Energy and Power Quality

The term *power quality* refers to voltage stability, frequency stability, and the absence of various forms of electrical noise (e.g., flicker and harmonic distortion) on the electrical grid. Alternating current with good power quality consists of voltage and current fluctuations with consistent sinusoidal shapes where voltage and current are in phase.

The key power quality issues associated with connecting wind turbines to the grid involve the times when the wind turbines come on and off line. Typically, wind turbines will be disconnected from the grid at low wind speeds and then come on line when the wind reaches a level sufficient to turn the rotor and generator at their rated speeds. In order for the rotor to not accelerate too fast, it is important that the generator becomes connected to the grid at the right time. This is accomplished using “soft starting” thyristors. These devices are akin to lighting dimmer switches in that they allow wind power to gradually be introduced to or subtracted from the utility grid. If “hard” switches were used instead, utility customers in the area of a wind farm could experience a brownout as the wind turbines came on line due to the energy needed to magnetize the generator. This would be followed by a power surge as the generator current rapidly ramped up into the grid. Thyristor switches avoid this problem by gradually energizing the generator. However, thyristors waste 1%–2% of the power running through them (Danish Wind Energy Association 2004b). For this reason, most wind turbine systems are equipped with a bypass switch, so that the thyristor is bypassed once the wind turbine system is fully engaged.

Additionally, wind power can create problems for “weak” electrical grids that are susceptible to voltage and frequency fluctuations. Wind power can exacerbate these problems, since even small fluctuations in wind power output can cause power surges, brownouts, and “flicker” (i.e., short-lived voltage fluctuations). Recent investigations have shown that the dynamics of these effects are complex and depend on the interactions in the mechanical components of the wind turbine systems (wind turbine, generator, gearbox, and two mechanical drive shafts) as well as variations in wind speed (Akhmatov et al. 2000).

These power quality issues can be addressed with the addition of power electronics in conjunction with the wind turbine/generator systems. Since most energy storage systems also require power electronics to rectify and invert the power that they are storing and discharging, these same power electronics arrays—likely with modifications—can be used to address the power quality issues. The benefit of energy storage systems in this regard will vary from location to location, depending on the extent of the power quality issues, in turn depending on the nature of the wind resource, the turbine/generator technology used, and the condition of the local electrical grid.

2.6. Previous Research

Renewable energy systems that are isolated from utility grids (i.e., "off-grid") are often combined with battery, pumped hydro, or other energy storage systems in order to make better use of their typically variable power production levels (e.g., Drouilhet and Shirazi 2002; Elhadidy and Shaahid 1999). Hydrogen-based storage systems are beginning to be used for this same purpose—in Iceland, on the Norwegian island of Utsira, in Germany, and in California in projects that Humboldt State University and others have conducted (Engel et al. 2004; Dunn 2001; Chamberlain and Lehman 1998).

Compared to remote off-grid applications, there has been less analysis (at least in the public domain) of integrating energy storage with renewable systems in larger-scale, grid-intertied applications. In these applications, energy storage can allow the intermittent renewable systems to function better in the context of utility dispatch requirements and overall regional electricity demand patterns.

Lawrence Livermore National Laboratory (LLNL) has been conducting analysis along these lines, and has developed a sophisticated network model to size components and calculate costs (Lamont 1997; 2001). In an investigation that examined the use solar photovoltaics (PV) with two types of generators (baseload and peaker) but no associated energy storage, the model produced similar findings to other analytical solutions with regard to the optimal level of renewable generation and the effect of PV penetration on system cost. The analysis found that increasing penetration of PV reduced emissions but had little effect on overall system cost until the PV systems became relatively inexpensive over time. In this study, the PV initially displaced significant generator capacity due to coincident production with grid peak demands, but at higher levels of penetration PV stopped displacing capacity and only displaced generation—with the fossil generators then operating at higher capacity factors (Lamont 2001).

More recently, LLNL has examined the role of energy storage coupled with wind power in the context of a Tehachapi area wind farm (Lamont 2004). The study examined the use of backup generators and energy storage to "firm up" the wind power and potentially improve its economics. The storage systems included an advanced battery and pumped hydro storage. The study concluded that neither the backup generator nor storage systems appeared promising in improving the economics of wind power by allowing "firm capacity" instead of "intermittent resources" contracts to be employed. Only under highly optimistic assumptions was the backup generator able to improve on the economics of wind power. Small-scale storage systems did provide rates of return on investment comparable to wind power in general, but these rates of return diminished with larger systems, meaning that the overall impact on the system (from the relatively small storage systems that were economically viable) would be small (Lamont 2004).

Bathurst and Strbac (2003) presented a generalized algorithm for optimizing the operation of energy storage systems used in conjunction with wind power and in the context of short-term and imbalanced energy markets. They found that most cases suggested that energy storage would add value to wind farm developments, except where wind availability forecasting errors are relatively low (i.e., if there is great uncertainty about the availability of the wind, then energy storage would be valued more highly). This suggests that better forecasting techniques can aid wind power economics and may reduce the needs for energy storage and/or backup generation. We note that there are also other potential benefits that energy storage can provide to utility grids that should be considered as well in a full analysis. Bathurst and Strbac (2003) also found that for most cases in which energy storage added value to wind farm developments, the storage systems needed to be relatively large: They examined storage with a rating of 6 MW for a 10-MW wind farm and needed to offer six hours of storage in order to capture the full added value that they could provide.

Korpaas et al. (2003) examined energy storage in conjunction with wind power in a Nordic setting. In their analysis, energy storage was a means of mitigating forecasting errors and arbitraging peak/off-peak power prices (e.g., shifting generation from time periods of relatively low economic value to periods of higher economic value). They concluded that energy storage could improve the value of wind power in energy markets, but hypothesized that the costs of energy storage devices "such as reversible fuel cells" were likely to be more expensive than transmission grid expansions as a way of accommodating wind power output alone. They suggested, however, that storage systems might be preferable where additional values were provided by the storage system, and where transmission grid expansions were environmentally or aesthetically undesirable.

In the broader literature, Schoenung et al. (1996) provided a good overall review of utility-scale energy storage systems and potential applications. The paper was noteworthy for its discussion of several potential uses of energy storage in utility electrical systems, particularly within the distribution infrastructure and including power quality support as well as the more traditional concept of shifting peak/off-peak resource availability to arbitrage between higher and lower prices. Grubb and Meyer (1993) provided a good overview of wind power systems, including the stochastic behavior of wind resources and the potential for storage to mitigate these fluctuations across various timescales.

We are aware of no previous analysis that compared energy storage systems in conjunction with wind power specifically in the California context that includes hydrogen energy storage as well as conventional and advanced battery systems, and that also includes the prospect of generating hydrogen to refuel hydrogen-powered vehicles.

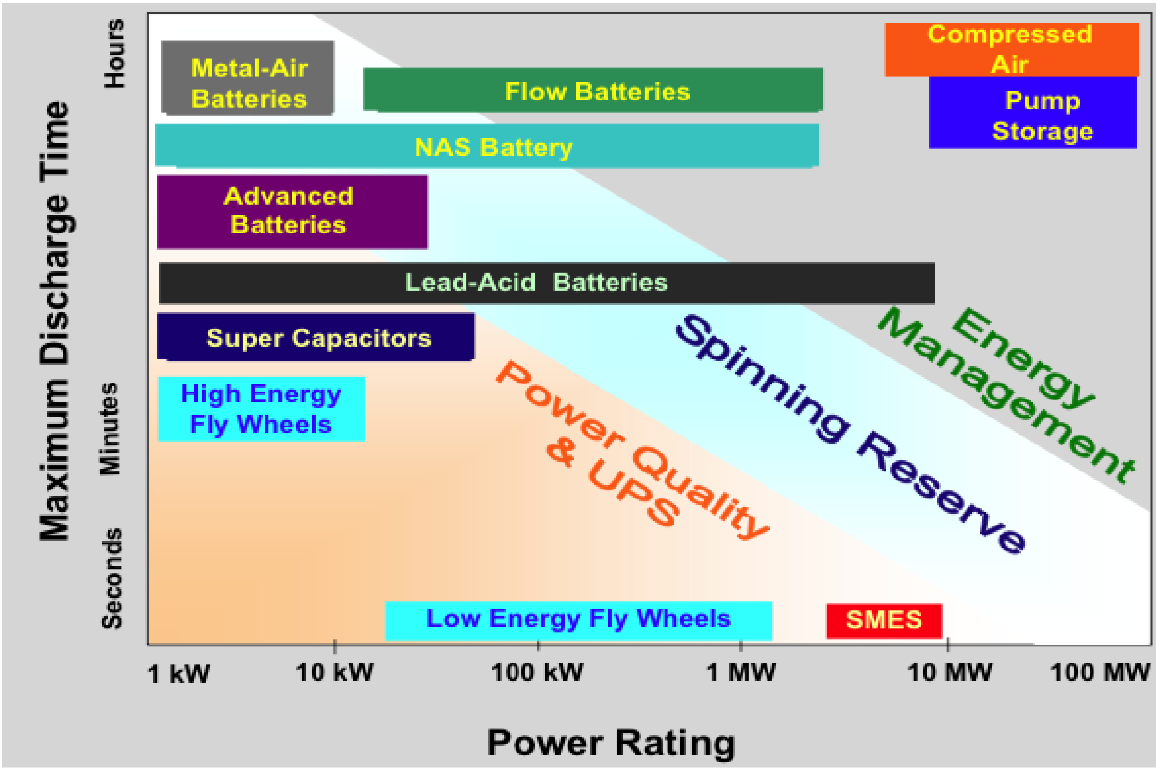
3.0 Review of Energy Storage Technologies—Cost and Performance

The intermittency of wind power and its general lack of correlation to peak electricity demand places wind power at a disadvantage relative to other resources that are more consistent in output and/or that better match their output with typical grid peaks (e.g., solar power). Under California's RPS, wind must compete against other renewable technologies that can provide more predictable and consistent electricity. Energy storage systems can provide wind with the ability to match the reliability characteristics of other renewables and even conventional electricity generators. Energy storage can provide supplementary or backup power in times of low wind and can also be utilized to improve the electrical quality of wind power output. Storage can also provide the added benefit of capturing surplus wind power that cannot be utilized by the grid due to low load demand or transmission constraints.

Energy storage systems vary with regard to costs, practical capacities, ramp-up times, power output, and other characteristics. This section provides an overview of several types of energy storage systems, discussing their advantages and disadvantages, as well as their potential application in conjunction with wind power. The systems evaluated here include the following:

- Compressed air energy storage (CAES)
- Pumped hydro energy storage (PHES)
- Hydrogen electrolyzer/fuel cell systems
- Hydrogen for hydrogen-powered vehicles
- Lead acid batteries
- Two types of advanced batteries: zinc bromine and vanadium redox
- Flywheels
- Superconducting magnetic energy storage (SMES) systems

Figure 4 shows several energy storage technologies arrayed across three types of applications and plotted in terms of typical system sizes and maximum discharge times. Electrolyzer/fuel cell systems are not included in the figure but would primarily be used for energy management systems (and fuel cells alone are being considered for power quality/uninterruptible power applications). As shown in the figure, CAES, PHES, and flow batteries are the primary technologies suitable for energy management applications, in addition to conventional lead acid batteries. Sodium sulfur batteries may also be an option for energy storage. These batteries are potentially low cost, but are expensive at present and have disadvantages associated with their high-temperature operation. Thus, we did not analyze sodium sulfur batteries in this study but may include them in subsequent investigations.



Source: Gyuk 2002

Note: NAS = sodium sulfur; SMES = superconducting magnetic energy storage; UPS = uninterruptible power supply

Figure 4. Energy storage systems and typical applications

3.1. Compressed Air Energy Storage

CAES systems utilize off-peak electricity to compress air that is then stored in an airtight reservoir, typically an underground geological formation such as a salt or limestone cavern. The energy is returned when the compressed air is released from the reservoir and run through a gas-fired combustion turbine. The compressed air replaces the compressor stage that is responsible for approximately 60% of the mechanical energy used by a gas combustion turbine. CAES systems have a short ramp-up time (on the order of 15 minutes) and can have high storage capacity and high output depending on the compressed air reservoir size. One performance analysis concluded that CAES could produce 30% more overall power than consumed, through integration with a gas turbine generator, compared with pumped hydro storage that consumed about 25% more power than later delivered back to the system (Najjar and Zaamout 1998). CAES systems coupled with turbine generators also offer better part-load performance than conventional turbine generators alone, providing another advantage (Najjar and Zaamout 1998).

CAES can provide numerous electricity services to support wind power such as firming/shaping, spinning reserves, capacity value, and voltage and reactive power support (Desai and Pemberton 2003). According to the Tennessee Valley Authority, 80% of the U.S. has the geology for underground storage of compressed air. The high output of CAES and its quick startup time make it an ideal technology to support expanded wind power penetration. In addition, the prevalence of suitable geology allows CAES to be readily adapted to numerous locations. However, unlike other storage technologies, CAES requires a large energy input during the power production process. The natural gas required to fire the gas turbines produces emissions associated with a typical gas plant. This may be incompatible with wind energy's "green" character. In addition, CAES systems may require a battery backup to respond to minute power fluctuations. CAES system's strongest characteristic is the ability to provide rapid-response bulk power for the duration of the peak demand period.

The only operating CAES facility in the U.S. is in McIntosh, Alabama. This system is rated at 110 MW and can provide 2,800 MWh of electricity at full charge. Another example of a CAES scheme is being considered for deployment in Norton, Ohio. This system is being planned for integration with a natural gas turbine power plant to be located near a 2,200-foot-deep inactive mine. Up to 2,700 MW of generation is planned in nine sequential increments of 300 MW. The abandoned mine is considered a good prospect for CAES with working pressures of 800–1,600 psi due to the fact that it is lined with dense rock with few natural fractures. The incorporation of CAES with the combustion generator is expected to produce similar emissions from the full 2,700-MW plant as would otherwise be expected from a 600-MW combustion turbine plant (Sandia National Laboratories 2001).

3.2. Pumped Hydro Energy Storage

Pumped hydro energy storage (PHES) facilities are the most mature energy storage systems, having been used since the late 1920s. This technology utilizes off-peak electricity to pump water from a lower reservoir into a higher reservoir with a hydraulic head[12] of between 30 and 650 meters. PHES facilities then produce electricity in the same manner as conventional hydro facilities by releasing the potential energy stored in elevated water through turbines. Like CAES, PHES can have high storage capacities and high outputs, depending on the reservoir size, and PHES can have an even shorter ramp-up time (1 to 4 minutes). PHES can also provide similar electricity services to support wind such as additional generation capacity and spinning reserves. PHES systems have an energy efficiency of between 60 and 78 percent (Bradshaw 2000). However, like CAES, PHES cannot respond as rapidly to power fluctuations as other storage technologies (e.g., batteries).

The expansion of PHES capacity is limited, as the best sites for PHES have already been developed. In addition, high capital cost and environmental opposition to new dams and reservoirs present obstacles to further development. However, these hurdles have not prevented the Sacramento Municipal Utility District (SMUD) from proposing a PHES at Iowa Hill near the Upper American River. This project is expected to benefit future integration of

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12. A hydraulic *head* is the distance between the higher and lower reservoirs in a pumped hydro energy system.

wind into the system by providing grid ancillary services[13] such as spinning reserves (Sacramento Municipal Utility District 2003).

Existing PHES facilities can be upgraded to allow for additional storage capacity and more efficient conversion. The most promising expansion opportunity for PHES lies in the development of facilities in which the lower reservoir is located underground. Japan has a few underground PHES facilities in service along with plans to construct additional PHES facilities. The most attractive attribute of PHES systems is rapid bulk power delivery that can contribute to meeting peak system loads.

3.3. Hydrogen Energy Storage

Hydrogen electrolyzer/fuel cell energy storage is a storage concept that utilizes off-peak electricity to produce hydrogen from water. The hydrogen serves as an energy carrier that can be stored as a liquid or a gas to be later utilized by a fuel cell to produce electricity. In combination with power electronics, hydrogen electrolyzer/fuel cell systems could provide wind with peak shaving, ancillary services, and greater dispatchability. However, hydrogen electrolyzer/fuel cell technology also can provide important services to wind in the damping of power fluctuations. Much like batteries, fuels cells can respond instantaneously to power fluctuations from wind turbines, much more quickly than CAES or PHES.

The efficiency and capital cost characteristics of electrolyzer/fuel cell systems depend on the type of technology utilized, the manner in which the systems are operated (lower load levels generally imply higher efficiency but at the expense of capital costs), and the time frame considered. Costs are relatively high at present but are projected to fall (at an uncertain pace), and efficiency is expected to increase as economies of scale and manufacturing experience take hold and continued technology development occurs. One major handicap for this type of system at present is the low round trip efficiency, reported at approximately 40% by some sources (e.g., Gordes et al. 2000), and likely closer to 30%–35% for practical systems in the near term. In addition, hydrogen electrolyzer/fuel cell technology has not been demonstrated in the hundreds of MW scale at which PHES and CAES already operate.

Also, it is important to note that the environmental impacts of hydrogen as a storage medium are strongly dependent on the manner through which the hydrogen is produced. Used in conjunction with wind power, hydrogen production and reuse has low environmental impacts. However, hydrogen produced through electrolysis from other electricity sources, such as coal or natural gas power plants, can have considerable environmental impacts (Lipman et al. 2004; Milborrow and Harrison 2003).

Despite these shortcomings, hydrogen as a storage medium has received much attention because of its flexibility. In addition to being used in fuel cells, the stored hydrogen can be utilized in modified combustion turbines or as a vehicle fuel. In this report, we consider the option of selling the hydrogen as a vehicle fuel rather than reconverting it back to electricity. Thus, hydrogen technology may gain a foothold not because of its inherent advantages over

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13. *Grid ancillary services* include a range of services required by utility grids to maintain power supply and power quality. These include spinning reserves, non-spinning reserves, voltage and reactive power support, and grid frequency regulation.

existing storage technologies, but because of its future promise and the significant political initiatives and cost incentives that are emerging for the development of hydrogen energy systems.

3.3.1. Hydrogen electrolyzer/fuel cell energy storage

Electrolyzers and fuel cells[14] have undergone extensive development in recent years, and several companies are now beginning to commercialize these devices. In comparison with other energy storage methods, electrolyzer/fuel cell systems are at present relatively expensive, with costs of approximately $3,000 to $5,000 per kW. However, these costs are expected to decline as these systems are produced in greater volumes, and as further technological advances and improvements are made.

Some companies are focusing on dedicated fuel cells or electrolyzers, while other companies, such as Proton Energy Systems and Hydrogenics Inc., are developing reversible or "regenerative" electrolyzer/fuel cells that can alternately function as either type of device. These devices could use excess electricity produced from renewable generating systems (e.g., wind power produced off-peak that has little value to electricity markets) to produce hydrogen. The stored hydrogen could then be converted back to electricity at a later time, using the same device operating in the fuel cell mode. Alternatively, and more likely in most real-world applications for technical and "duty cycle" reasons, hydrogen can be produced using dedicated electrolyzers, stored, and then reconverted into electricity using dedicated fuel cell systems.

Figure 5 shows a block diagram of an electrolyzer/fuel cell system that is coupled with hydrogen storage and power conversion systems. The electrolyzer/fuel cell could be one reversible device, or a dedicated fuel cell and dedicated electrolyzer could be used. Proton exchange membrane (PEM) fuel cell technology has been the most explored of the various fuel cell technologies for reversible electrolyzer operation, but solid oxide and alkaline fuel cell systems can also be reversed to produce hydrogen. In the analysis conducted in this report, we assume the use of separate fuel cell and electrolyzer devices, as this avoids various complexities associated with the reversible use of the same device (e.g., system design considerations that make it challenging to optimize one device for both purposes, durability issues, and the inability to simultaneously produce and use hydrogen), but we note that, in principle, lower costs could potentially be achieved with a single reversible device if the above concerns can be addressed.

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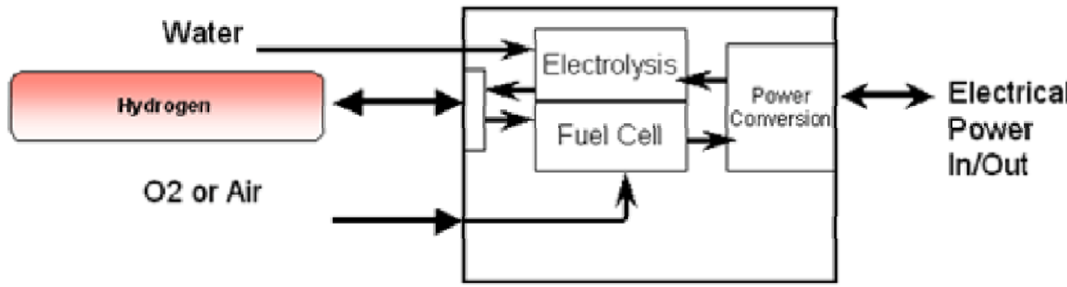
14. An *electrolyzer* is an electrochemical device that converts water and electricity to hydrogen and oxygen using the process of electrolysis. A *fuel cell* uses the reverse electrochemical process to convert hydrogen and oxygen to electricity and water. Some types of fuel cells can operate in "reverse mode" as electrolyzers.



Source: Proton Energy Systems (2003)

Figure 5. Diagram of reversible electrolyzer/fuel cell with hydrogen storage

3.3.2. Hydrogen for hydrogen-powered vehicles

Hydrogen as an energy carrier has garnered the most attention as a vehicle fuel for hydrogen fuel cell or combustion engine vehicles. In addition to the FreedomCAR program by the U.S. Department of Energy (DOE), California has recently embarked on a bold hydrogen agenda under Governor Schwarzenegger. This California Hydrogen Highway Network initiative was announced by the governor with Executive Order S-07-04 on April 20, 2004. The vision for the California Hydrogen Highway Network is to put in place a refueling infrastructure by 2010 to support hydrogen vehicle introduction in California. The executive order states:

> [It] is ordered that the State of California is committed to achieving a clean energy and transportation future based on the rapid commercialization of hydrogen and fuel cell technologies….so that by 2010 every Californian will have access to hydrogen fuel, *with a significant and increasing percentage produced from clean, renewable sources*.
>
> Be it further ordered that…*appropriate incentives shall be provided* to encourage the purchase of hydrogen-powered vehicles and *to encourage the development of renewable sources of energy for hydrogen production*. (emphasis added)

This initiative suggests that renewable sources of hydrogen production could become an important area of development for California, and also that incentives could be put in place to help clean and renewable sources compete in the marketplace during the exploration of initial hydrogen energy markets.

The most noteworthy effort along these lines in California is being funded by the South Coast Air Quality Management District (SCAQMD) and DOE, with additional funding from partners Wintec Energy, Stuart Energy Systems, SunLine Transit, Quantum Technology, and ISE Research. The wind-generated hydrogen option will be demonstrated with three wind turbines, and as much as two kilograms per hour of hydrogen will be generated, compressed, and stored for use in either a fuel cell bus or other hydrogen-fueled vehicles. The amount of power produced by each of the turbines—200,000 kWh electricity per year—could be used to produce over 3,000 kg hydrogen, enough to power a fuel cell bus for about 30,000 miles (ISE Corp 2004).

Given this interest in hydrogen refueling for vehicles, we consider in this report the possibility of using hydrogen generated from excess wind power (at off-peak times) as a vehicle fuel. We assume that the excess electricity can be transmitted to hydrogen refueling stations where electrolyzers produce hydrogen, where it is stored and then later dispensed to vehicles.[15] We compare this potentially high-value use of hydrogen with the alternative of reconverting it to electricity using fuel cell systems, and to other energy storage using conventional lead acid and advanced zinc bromine battery systems.

Figure 6 shows a picture of an electrolyzer system being installed near a wind farm in Palm Springs, California. This system will demonstrate the use of excess wind power to produce hydrogen, which then will be used to refuel hydrogen-powered vehicles.

Figure 6. Hydrogen electrolyzer system being installed near wind farm in Palm Springs, California

15. Our detailed model results suggest that this assumption may not be valid for certain periods of the year when we show a tendency for electricity to be transmitted at times of relatively high grid demand, when transmission may be constrained (see Figure 14 for more details.). We also recognize that there may be cheaper ways to produce hydrogen (either from lower-cost electricity sources or through other means such as natural gas reformation), with which this scheme would have to compete.

3.4. Lead Acid Batteries

Batteries have long been utilized as a means to store electricity. Applications have primarily included transportation systems as well as for stationary energy storage. Batteries store energy in chemical form by alternately creating electrically charged ions (during battery charging) and then using the ions to create a flow of electrons (during battery discharge). Batteries produce power in DC form that must then be inverted to AC if the batteries are used in conjunction with an AC power system.

Conventional lead acid batteries have been widely used in utility-scale applications but have limited durability and high maintenance requirements. Lead acid batteries are relatively inexpensive, however, with costs on the order of $100 per kWh for typical “wet” designs and $125–200 per kWh for more modern “valve regulated” designs (Schoenung et al. 1996). This low cost has made lead-acid batteries of continued interest, despite their technical shortcomings. Lead acid batteries also have potentially significant environmental impacts associated with manufacture and disposal, but proper disposal and recycling of the batteries can mitigate some of these concerns.

3.5. Advanced Battery Energy Storage

Batteries have long been utilized as a means to store electricity. However, conventional batteries, such as lead acid, have limited durability and high maintenance requirements. A new wave of battery storage technology is attempting to address the shortcomings of previous battery designs, with considerable progress in key technical characteristics compared with past designs. In particular, flow batteries, such as the zinc bromine battery (ZBB) and the vanadium redox battery (VRB), have found a niche in supporting intermittent renewables and in other utility-scale applications. Other advanced battery types suitable for utility-scale applications include sodium sulfur, nickel cadmium, and nickel metal hydride. Several of these battery systems (sometimes called “BESS” for battery energy storage system) have been deployed around the world, with the largest current system being a Saft Battery Company nickel cadmium system designed for 27 MW of backup power for 15 minutes. The system was installed by the Golden Valley Electric Association in Alaska and has been operational since November 2003 (De Vries 2003).

Flow batteries employ a system to circulate reactants from external reservoirs into the battery stacks that consist of bipolar electrodes located between two monopolar terminal electrodes. This design promotes longevity of the battery, since the electrodes do not participate in the reaction. This prevents deterioration from repeated cycling, which leads to a loss in performance for other battery types. This design also allows system power and system energy storage capacity to be tailored independently (Menictas et al. 1998). Flow batteries also typically have greater charge efficiency[16] (approximately 90%) than conventional batteries (Holstrom 1995). In addition, flow batteries can be left indefinitely in a zero percent state of charge without

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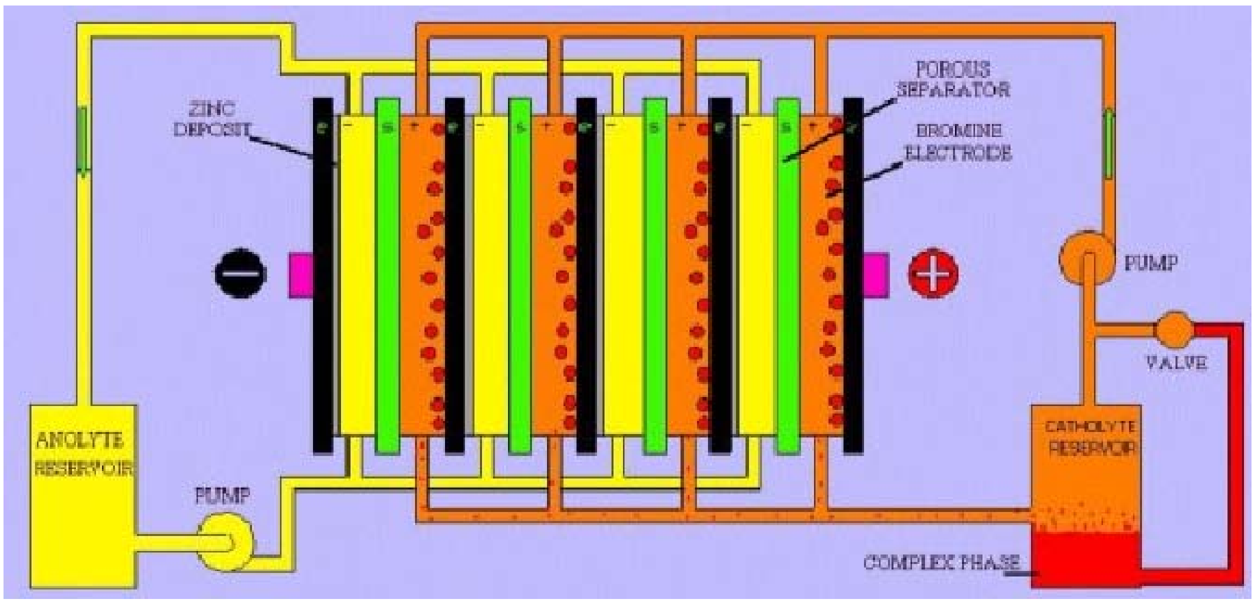
16. *Charge efficiency* is a measure of the energy lost during battery charging. It is the ratio of the energy in the battery (that was added during a particular charge episode) to the energy that was used to charge the battery during that same charging period.

loss in performance. Last, the circulating electrolyte allows greater temperature control of the battery stacks, further increasing longevity (Norris et al. 2003).

Flow batteries in conjunction with sophisticated power electronics can provide useful services to wind generation. In a study evaluating ZBB, researchers identified real-time damping of power fluctuations along with peak shaving,[17] bulk power to meet peak system loads, ancillary services, and firm system capacity as services that a ZBB system could provide (Norris et al. 2003). In the damping capacity, ZBB could provide additional power during a momentary drop in wind velocity and absorb additional power during a gust, shaping the power profile far more quickly than CAES or PHES systems. For example, in this study the 1.5 MWh ZBB system could damp a power fluctuation of plus or minus 1.5 MW (Norris et al. 2003).



Source: ZBB Energy Corp. 2004

Figure 7. Schematic of a zinc bromine flow battery

While under development for many years as potential electric vehicle batteries, ZBB systems are relatively novel with regard to utility-scale applications. The ZBB Energy Corporation has a three-year contract with the Energy Commission to test a 2-MWh ZBB system in the context of utility grid support. The first of four 500-kWh units is scheduled to be tested starting in May of 2005 as part of the Distributed Utility Integration Test program with Pacific Gas and Electric Company (PG&E) in San Ramon, California. Around the end of 2005, three additional units will be shipped to PG&E for testing (Lex 2004).

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17. Energy storage systems can provide "peak shaving" if deployed on the demand side of the system. Conversely, on the utility or "supply" side of the system, energy storage systems can help to meet system peak demands.

Vanadium redox battery systems operate in the same fashion as ZBB systems and have been implemented in Japan to dampen power fluctuations from wind turbines. Both ZBB and VRB can provide valuable services for wind power—in particular, power stability. The additional potential functions of peak shaving, ancillary services provision, and firming of system capacity do not appear to be as attractive for flow batteries as for CAES or PHES, due to the relatively smaller capacity of practical flow battery systems. There has yet to be a flow battery that approaches the potential capacity of PHES or CAES. However, at a smaller scale, flow batteries appear to be a promising new technology.

As with hydrogen systems, advanced battery costs are also expected to decline over time, though the declines are generally more modest than are expected for the more "exotic" electrolyzer/fuel cell technologies. Conventional battery technologies are considered mature with small, if any, future cost reductions expected.

3.6. Flywheels

Flywheels store kinetic energy in a rotating mass with minimized friction losses to improve efficiency. These devices have been used in train engines and other road vehicles, and in centrifuges. Flywheels rely on variable frequency cyclo-converters to compensate for the speeding and slowing of their rotational frequency in response to alternately absorbing and discharging mechanical energy (and in practical applications helping to "load level" the power demand) and storing it as kinetic energy. In utility applications, flywheels would be used for load-leveling utility grids and helping to "ride through" momentary power outages, as well as for potential integration with wind turbine and other power systems (Schoenung et al. 1996).

Modern flywheel systems are made of high-strength composite materials and manufactured to exact tolerances, leading to relatively expensive costs on an energy-stored basis (but potentially relatively low costs on a power basis due to the rapid discharge characteristics of flywheel devices). Some designs involve superconducting magnetic levitation to reduce bearing drag and improve efficiency, but this adds cost and cooling energy load and is still under development to improve system performance. The Boeing Corporation developed a 1-MWh flywheel system for utility applications in the 1990s, but with only limited commercial success. Current flywheel system developers for utility applications include Active Power, AFS Trinity, Beacon Power, and Urenco Power Technologies.

3.7. Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) systems are a more novel technology that stores energy in the magnetic field created by the flow of direct current in a coil of cryogenically cooled, superconducting material. A SMES system includes a superconducting coil, a power conditioning system, a cryogenically cooled refrigerator and a cryostat/vacuum vessel. SMES systems are highly efficient at storing electricity (greater than 95%), and can provide both real and reactive power, but are still in the development and testing phase. These systems are used to provide grid stability in distribution systems and power quality at manufacturing plants requiring ultra-clean power, such as microchip fabrication facilities. Developers of SMES systems include American Superconductor, Babcock and Wilcox, Intermagnetics General Corporation, and Superconductivity, Inc.

3.8. Summary of Advanced Storage Technology Characteristics

Table 1 summarizes key characteristics of advanced storage system technology solutions for energy management applications. As shown in the table, different technologies have strengths and weaknesses relative to one another with regard to cost, lifetime, and efficiency characteristics. CAES and PHES are relatively expensive from a capital cost perspective, but they have long lifetimes and potentially high efficiencies. Electrolyzer/fuel cell systems are also expensive, particularly for the near term, and they have medium (and at this point somewhat uncertain) expected durability/lifetime characteristics. Flow batteries have relatively low costs and high efficiencies but relatively low durability.

Table 1. Summary of key characteristics of advanced storage systems for energy management applications

	CAES	PHES[2]	Electrolyzer/ Fuel Cell	ZBB[4]	VRB	Lead Acid Batteries	Flywheels[6]
Typical Size Range	50–350 MW[1]	8–100 MW	50 kW – 1 MW	10 kW –5 MW	10 kW – 5 MW	10 kW – 5 MW	1–10 MW
Capital Cost (present)	\$350–\$450/kW[1]	\$1,100–\$2,000/kW	Elect: \$700–\$2,000/kW FC: \$3,000–\$4,000/kW	\$400/kWh	n.e.	\$100–\$150/kWh	\$200–\$250/kW (\$100–\$800/kWh)
Capital Cost (future projections ca. 2020)	n.e.	\$800/kW	Elect: \$300–\$400/kW FC: \$500–\$750/kW	\$300/kWh	n.e.	\$80–\$120/kWh	n.e.
Typical Maintenance Cost	\$7.5/kW/yr fixed plus \$0.004/kWh variable[6]	\$4.3/kW/yr fixed plus \$0.0043/kWh variable[6]	\$0.002–\$0.01/kWh	\$20/kW/yr	n.e.	\$1–\$2/kW/yr fixed plus \$0.005/kWh variable[6]	\$7.5/kW/yr fixed plus \$0.004/kWh variable[6]
Typical System Life	20 years?	20 years?	Elect: 10–20 years between stack refurb. FC: Goal of 5+ years between stack refurb.	2,000 cycles	n.e.	300–500 cycles	20 years?
Round Trip Electrical Efficiency	~70% but variable based on integration with turbine generator	60%–78%	30%–40%[3]	76%	78%[5]	80%–85%	~90%

Notes: CAES = compressed air energy storage; PHES = pumped hydro energy storage; VRB = vanadium redox battery; ZBB = zinc bromine battery; n.e. = no estimate available

[1] Williams 2002

[2] Bradshaw 2000

[3] For PEM systems and depending on duty cycle and technology status; potentially somewhat higher for solid oxide systems

[4] Lex 2004, except future cost projection

[5] Hawkins 2000

[6] Schoenung et al. 1996

4.0 Analysis of Energy Storage in Conjunction with Wind Power in California

This section presents the assumptions and results of the modeling and analysis of various types of energy storage coupled with potential wind power developments in California. First, we review various models that are suitable for this type of analysis or that could be readily modified, and present the rationale for selecting the HOMER model. Second, we present the application of the HOMER model in the California context, along with an overview of the scope and nature of the modeling effort. Third, we present detailed modeling input assumptions. Finally, we present modeling and analysis results.

4.1. Comparison of Existing Models and Analysis Methods

Several models are available with at least some capability for analyzing energy storage in conjunction with intermittent renewable resources. These models vary in terms of their capabilities, structure, scale of application, and computing code/platform. There also are additional analytical methods that can be employed that do not require detailed models, but these tend to have significant limitations for analysis of energy storage systems in conjunction with wind power.

The simplest type of analytical method uses "load duration curve" analysis. A load duration curve displays the amount of time a particular level of electricity is demanded. The curve plots the hours of the year, from 0 to 8,760 hours, on the x-axis and the amount of electricity demanded on the y-axis. A Fourier transform is performed on annual hourly load data to produce the load duration curve. Utilizing this curve, one can estimate the number of hours that baseload plants, shoulder load plants, and peaker plants are utilized. Analysis of load duration curves can produce generalized estimates of how much energy storage would be required to assist in peak shaving. However, this type of analysis is not particularly useful for evaluating the use of energy storage systems in conjunction with wind power, as it obscures the details of the hour-by-hour fluctuations in wind resource availability.

4.1.1. HOMER

The Hybrid Optimization Model for Electric Renewables (HOMER) was developed by the National Renewable Energy Laboratory (NREL) to optimize electric power systems for both off-grid and grid-connected power systems. The HOMER model allows the user to select a system architecture consisting of specified components and system conditions including power sources, storage, and load. HOMER can include conventional and renewable energy systems as well as hydrogen production. HOMER evaluates the technical and economic feasibility of the user-specified systems while allowing for variation in technology costs and resource availability (NREL 2004).

4.1.2. WinDS-H2

The Wind Deployment Systems with Hydrogen (WinDS–H2) model is a market analysis tool developed by NREL. The basic WinDS model is "a multi-regional, multi-time-period, Geographic Information System (GIS) and linear programming model, which was developed to simulate the capacity expansion of the electric sector and assess the market potential of U.S. wind resources" (NREL 2004). The WinDS–H2 model adds hydrogen production, storage, and transport technologies to the WinDS model (NREL 2004). The WinDS–H2 model is being used in a NREL project attempting to forecast the likelihood of wind power providing economical electricity generation and hydrogen production (Blair 2004).

4.1.3. CETEEM

The Clean Energy Technology Economics and Emissions Model (CETEEM) was developed by the University of California, Berkeley, to evaluate the economics and emissions from different energy technologies. This model combines MATLAB, Simulink, and Excel tools to create an integrated analysis tool. CETEEM has been implemented to analyze PEM fuel cell systems using hydrogen supplied by steam methane reformers, as well as combined production of electricity and hydrogen from "hydrogen energy stations." CETEEM is being further developed to evaluate other fuel cell and clean energy technologies (Lipman et al. 2002).

4.2. Introduction to the HOMER model

The HOMER model was selected to perform this evaluation of energy storage for intermittent renewables in California. HOMER is the most fully developed of the available intermittent renewables/storage models and analysis tools and the one best suited for the goals of this analysis. The HOMER model's flexible system architecture and user-friendly interface allow the researchers to readily model the various wind power/storage cases considered.

HOMER was initially developed to analyze small grid-independent wind systems, and the model exhibits a few limitations when used to analyze larger grid-connected wind farms and their interactions with electrical grids. The inclusion of additional flexibility in future versions of HOMER (e.g., the ability to more carefully control the output of energy storage systems to coincide with utility grid peak demand and price periods), would be helpful in carrying out more sophisticated analysis of the economics of wind farms that are simultaneously coupled with energy storage and the broader electricity grid.

The first step in using HOMER involves the user selecting power system characteristics (such as load demand), system components (such as wind turbines and ancillary equipment), and performance and cost parameters for each component. Based on these characteristics, HOMER runs a simulation that produces outputs (such as, total electricity load, load for the various components of the system, electricity and/or hydrogen produced from the components of the system, and annualized cost of each component). Thus, a quantitative comparison of different energy storage systems deployed in conjunction with example wind farms can be conducted.

4.3. Application of HOMER to California: Inputs and Assumptions

The HOMER model was used to characterize energy storage within the California grid with increasing penetration of wind power. HOMER was utilized to model four different wind sites in California: Tehachapi Pass and San Gorgonio Pass in Southern California and Altamont Pass and Solano County in Northern California. As shown in Figure 8, these are among the top wind power sites in California for continued development.[18]

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18. The Tehachapi, San Gorgonio, and Altamont regions are shown in the figure. The Solano region is located approximately 75 miles north of the Altamont region.

The HOMER analysis considered two different time frames: 2010, when we projected 10% wind penetration, and 2020, when we projected 20% wind penetration (based on capacity and relative to 2003 peak electricity demand). In addition to varying the wind penetration levels, we also made various economic assumptions for these two time frames, detailed below. System characteristics, such as site-specific wind profiles and load demand figures, were also included.

Source: U.S. DOE Energy Information Administration 2002

Figure 8. Major wind energy resources in California

We divided California into a southern zone and a northern zone based on the fact that California is divided into two major generation and load zones as a result of the electricity transmission constraint imposed by Path 15. The high levels of wind penetration modeled in this project present stability issues for the electricity grid. At these levels of penetration, the grid may be unable to accommodate wind power without either reducing the output of baseload plants, which tend to operate at higher efficiencies near maximum output, or shutting down wind turbines to prevent excess wind power from creating an imbalance in the grid. Energy storage systems can address the issue of excess wind power and allow the full use of the wind regardless of load demand. The project examined and modeled three energy storage systems to store excess power from the wind turbines: (1) a solid-state (lead acid) battery system; (2) a flow (zinc bromine) battery system; and (3) an electrolyzer-fuel cell system. A fourth alternative, producing hydrogen at an off-site location for sale to hydrogen-powered vehicles, was also modeled.

For each option, the system architecture was composed of technical components including wind turbines (the primary electricity source), the electricity grid, a converter (inverter/rectifier),[19] and either a battery storage system or a hydrogen production system. The battery systems consisted of battery modules, while the on-site hydrogen production and electricity generation system consisted of an electrolyzer, a hydrogen storage tank, and a fuel cell system. The off-site hydrogen production system consisted of an electrolyzer, compressor, and high-pressure hydrogen tank, which were assumed to be integrated with an existing hydrogen dispensing station.

The allocation of wind power resources between Northern and Southern California was based on California's technical wind potential (Energy Commission 2003d). Approximately 90% of the technical wind potential is located south of Path 15 and 10% north of Path 15. Utilizing this information, the 2010 scenario projected that 1% of California's electricity would come from Northern California wind farms, while 9% would come from Southern California wind farms. In the 2020 scenario, we projected a doubling of wind power with 2% of California electricity derived from Northern California wind farms and 18% from Southern California wind farms.

Given limitations of the HOMER model where only one wind resource can be analyzed at a time, we characterized the power derived from each individual wind site to represent the entire contribution to the wind power for the given area (Altamont or Solano for Northern California and San Gorgonio or Tehachapi for Southern California). For instance, for the model scenario characterizing 2010 Northern California wind power, we took the power generated from Altamont or Solano separately as representing all of the wind power in Northern California. While not as realistic as a more complex analysis that would characterize multiple wind sites at the same time, this method allows us to examine the impacts of variation in the wind resource at these typical sites.

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19. The *rectifier* converts power from alternating current (AC) to direct current (DC), and the *inverter* converts power from DC to AC.

The wind penetration figures were derived as a percentage of the 2003 California load demand within the "NP15"[20] and "SP15"[21] regions as released by the CAISO. The wind farms generated power based on the wind profile for a given site and the characteristics of the specified wind turbine. The wind turbine performance was based on the power curve of the Vestas V47, a 660-kW wind turbine. The turbines were rated down by a factor of eight, to 82.5 kW, in order to "fine tune" the percentage of wind penetration in each case. HOMER was run with these parameters in place and produced an "electricity generated from wind turbines" figure that was adjusted by changing the number of wind turbines at a given site until the desired wind power penetration level was achieved.

Hourly wind data for one year were obtained for the four different wind farms from two primary sources: the Lawrence Berkeley National Laboratory (see Wiser 2005 for details) and the California Wind Energy Collaborative (CWEC). The wind farms included in this analysis were Altamont Pass in Alameda County, Solano Wind Farm in Solano County, San Gorgonio Pass in Riverside County, and Tehachapi Pass in Kern County. The data from Altamont Pass, Solano County, and San Gorgonio Pass consisted of hourly wind readings from an anemometer for an entire calendar year patched together from several different years. This was necessary because continuous wind data were not available for one entire calendar year. In addition, any missing data points were filled in by summing the wind speeds from the hour before and the hour after and dividing by two. If consecutive data points were missing, the missing data points were filled by summing the wind speeds from the previous two hours and dividing by two. The wind data from Tehachapi Pass were obtained from a CWEC project that measured wind speed from individual wind turbines and then averaged them over the site (Jackson 2004). These data were then normalized to allow for public release. Figure 9 shows a graphical output from the HOMER model displaying the power generated from the Tehachapi and Solano wind farms in 2020. Note the variability of the power output as a function of the location and season as well as the probability distribution of the wind power at the two sites.

Additional data gathered for this project included California electrical load and generation data obtained from the CAISO OASIS Web site[22]. The load and generation data were divided into two areas: the area north of Path 15 (NP15) and the area south of Path 15 (SP15). Hourly load data from one weekend day and one weekday for each month were input into HOMER to approximate the load demand, with NP15 load data representing the load center for the Altamont and Solano sites, and SP15 representing the load center data for San Gorgonio and Tehachapi wind power. HOMER takes these baseline load data and factors in a specified hourly and daily load "noise."[23] For this project we selected 6% hourly noise and 3% daily noise. In addition, NP15 and SP15 generation data were obtained from OASIS in order to estimate baseload generation for each area. Baseload generation was varied from month to month, taking

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20. The area to the north of the Path 15 main transmission system between Northern and Southern California.

21. The area to the south of Path 15.

22. The CAISO OASIS Web site can be found at: http://oasis.caiso.com.

23. Hourly and daily load *noise* are the hourly and daily variations around a baseline estimate of grid electrical loads.

the weighted average of the lowest generation figure for one weekend day and one weekday for each month.

Tehachapi **Solano**

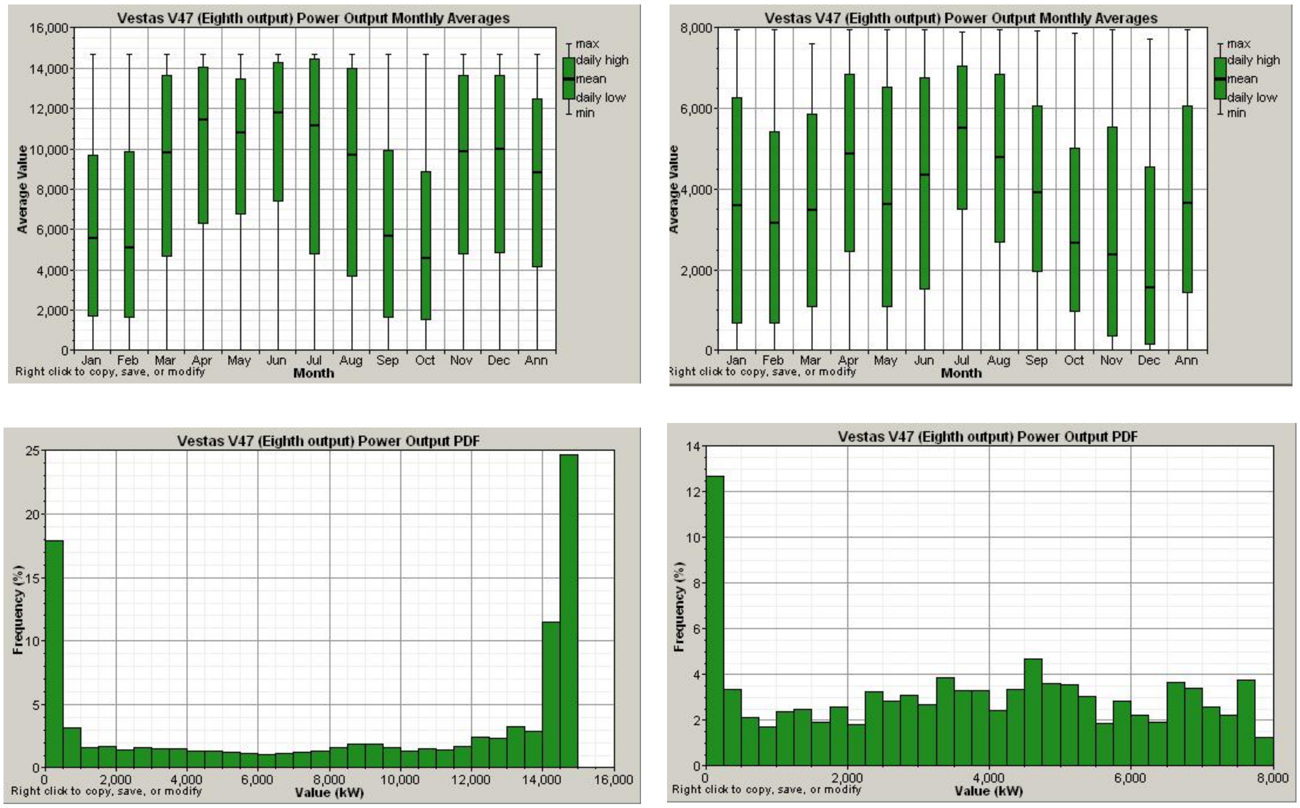


Figure 9. HOMER output for electricity generated from wind in 2020

The HOMER simulations were run over a 20-year project lifespan utilizing a 6% annual interest rate, yielding a capital recovery factor[24] of 0.087 for capital equipment depreciation. As discussed in Sections 1 and 2.1.2 and based on the current rules being proposed for valuation of intermittent renewable resources in California, electricity produced from the energy storage devices was expected to be valued through fixed-price contracts. The value of the electricity produced from wind power and storage was assumed to be $0.065 per kWh, based on our assessment of likely wind power bid prices under the proposed MPR-based system. This was composed of $0.05 per kWh (the bid price) plus an assumed production tax credit of $0.015 per kWh.

In summary, scenarios were constructed and HOMER was run to determine the relative net present cost of equivalent-capacity energy storage systems across the four different sites and two different time frames. Given the capabilities of the HOMER model, first-order simulations

24. A *capital recovery factor* is a fixed factor used to amortize capital over various years of a project analysis. The capital recovery factor is a function of the lifetime of the capital and the interest rate and effectively assumes "straight line" depreciation of capital.

were run and data were collected to allow for second-order runs of HOMER to create the desired scenarios. In the first run, the load demand and the number of wind turbines required to reach the specified wind penetration were input to HOMER, and a simulation was run. The output consisted of hourly load demand and hourly wind power figures that were then placed into a spreadsheet with 8760 cells to characterize each hour of the year. Within this spreadsheet, a baseload electricity figure was entered along with an imports/peaker plant electricity figure to determine total electricity generated for a given hour. The spreadsheet was design to make sure that power supplied met power demanded. When the sum of wind power plus baseload did not meet demand, imports/peaker plants made up for the power deficit. When the sum of the wind power plus the baseload exceeded load demand, excess power was available for either sale or energy storage.

The excess power figure derived from the first-order run of HOMER was used to set the target for the second-order run. The second-order run of HOMER involved increasing the number of wind turbines until the annual excess electricity generated equaled the annual excess electricity determined within the spreadsheet. This number of turbines was then utilized in each of the energy storage system cases to determine the amount of energy sent to battery storage or the electrolyzer, the amount of excess power above the capacity of the energy storage system or hydrogen production system, and the amount of electricity transmitted in the case of grid sales.

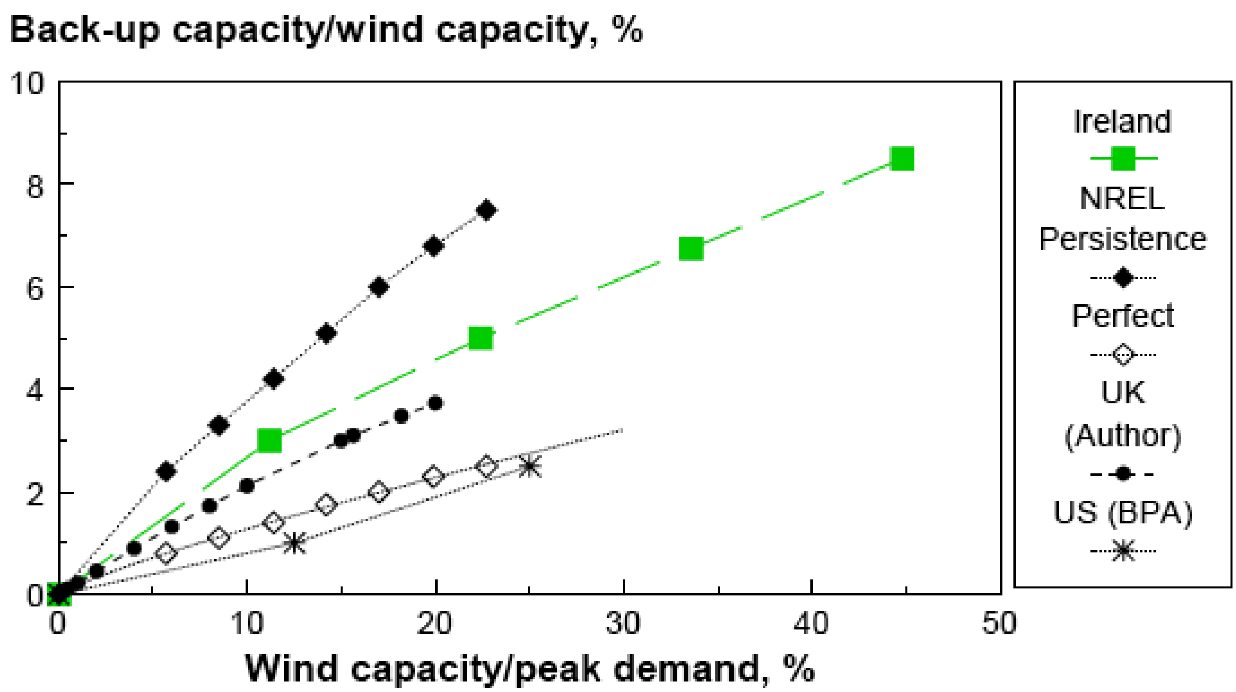
In addition, transmission capacity between Northern and Southern California was taken into consideration. Two analyses were run to evaluate the impact on the energy storage systems and the hydrogen-producing systems of electricity transmission between Northern and Southern California. In one case, 5,400 MW of transmission capacity, equal to the recently upgraded Path 15 transmission capacity, was available. In the other, "transmission constrained" case, zero transmission capacity was available, forcing all electricity produced in the north or the south to be utilized in that area.

The energy storage systems were sized to contain 10% of the hourly nameplate capacity of the wind farm, and with one hour of storage, as an upper bound on the amount of storage that would likely be considered, though we note that even larger systems have been found to be potentially economically attractive (Bathurst and Strbac 2003) if not advantageous from a technical perspective. For instance, if the wind farm was rated at 500 MW, the energy storage system was sized to 50 MWh. Previous research has indicated that the amount of storage or backup generation required for wind from a forecasting-error correction standpoint is actually rather modest for wind penetration levels below about 30% of total capacity. Estimates are on the order of perhaps 2%–6% for wind penetration levels of 20% of total system capacity (i.e., about 6%–10% of energy output) and 3%–8% for wind penetration levels of 30% of capacity (or 10%–15% of energy output) (Milborrow 2004a).

Figure 10 presents estimates of the amount of backup capacity needed as a percentage of wind capacity, based on research conducted by NREL, the Bonneville Power Administration (BPA), and in the United Kingdom.[25] For example, based on the BPA data this figure suggests that

25. These sources include those that are in press and otherwise not generally available—see Milborrow (2004a) for details.

when wind power reaches 12.5% of total system capacity (or about 5% on an energy-supplied basis), 1% of total system capacity would be needed to back up that level of wind power. With 25% wind power capacity (or about 10% on an energy-supplied basis), about 2.5% of system capacity would be needed in backup capacity. These data suggest that for the 10% and 20% wind penetration scenarios considered here (on an energy basis), 10% energy storage would be ample from the perspective of compensating for wind forecasting errors, even for the 2020 scenarios where wind supplies 20% of total system energy. In the sensitivity analysis (Section 4.7), we also look at smaller energy storage systems and examine the impact on system economics of downsized storage relative to our 10% storage scenarios.



Source: Milborrow 2004a

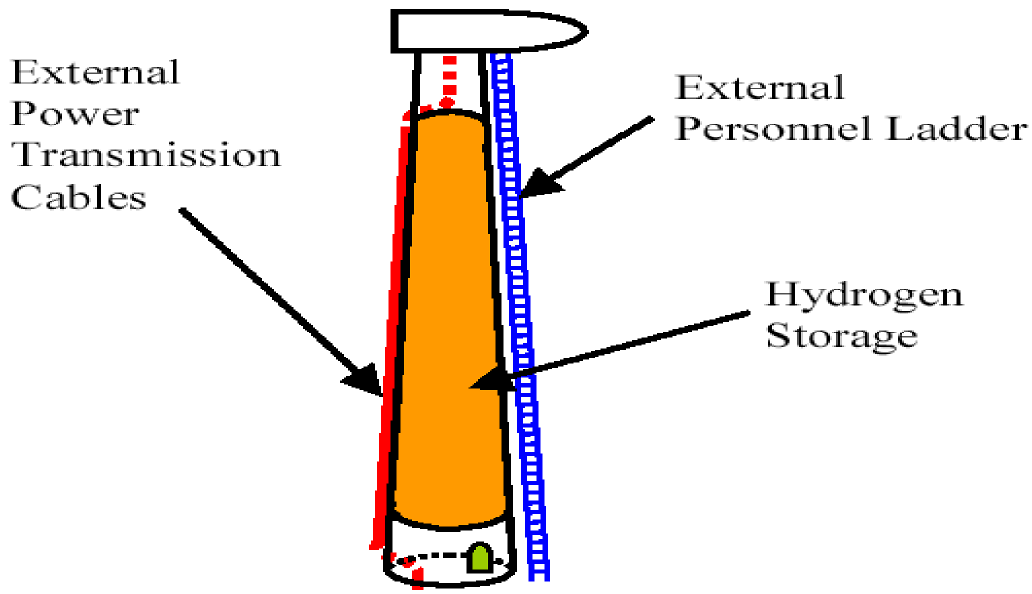
Figure 10. Estimates of backup capacity required relative to wind penetration level

For the hydrogen systems, the higher heating value (HHV) of hydrogen (39 kWh/kg) was used to size the hydrogen tank that would serve as the measure of energy storage capacity for the electrolyzer/fuel cell scenario. The same-capacity hydrogen tanks were utilized in the hydrogen production scenario as in the electrolyzer/fuel cell scenario. In addition, the converter specified in each of the energy storage and hydrogen production scenarios was sized to handle the maximum charge rate of the individual battery systems, and in the two scenarios involving hydrogen, two cases were considered, one with the converter sized to match the lead acid battery system converter and one with the converter sized to match the flow battery system converter. The HOMER default converter performance numbers were used for the modeling runs.

4.4. Energy Storage Scenarios Analyzed

4.4.1. Scenario 1: On-site electrolyzer/fuel cell storage system

The first scenario examined was an on-site electrolyzer/fuel cell storage system that consisted of an electrolyzer, a hydrogen tank, and a fuel cell system. This system utilized excess electricity from the wind turbines to power an on-site electrolyzer to produce hydrogen. The electrolyzer was sized to match the converter size as specified above. Two cases were evaluated: (1) an electrolyzer/fuel cell storage system with an instantaneous power equal to the solid-state battery system (SSB) and (2) an electrolyzer/fuel cell storage system with an instantaneous power equal to the flow battery system (FB). In the first case, the hydrogen was assumed to be stored within the turbine tower—an interesting option that could significantly reduce the costs of storage.[26]



Source: Kottenstette and Cotrell 2003

Figure 11. Conceptual drawing of hydrogen storage in wind turbine tower

Kottenstette and Cotrell (2003) estimated that 1,000 kg (2,200 lbs) of hydrogen could be stored in modified (retrofitted) wind turbine towers at a cost of about $90,000, compared with about $260,000 for conventional hydrogen storage tanks. Their results showed that the relatively low costs of their systems occur at a storage pressure of about 1,100 kilopascals (160 psi), with increasing costs at both higher and lower pressures. Figure 12 presents their cost breakdown for

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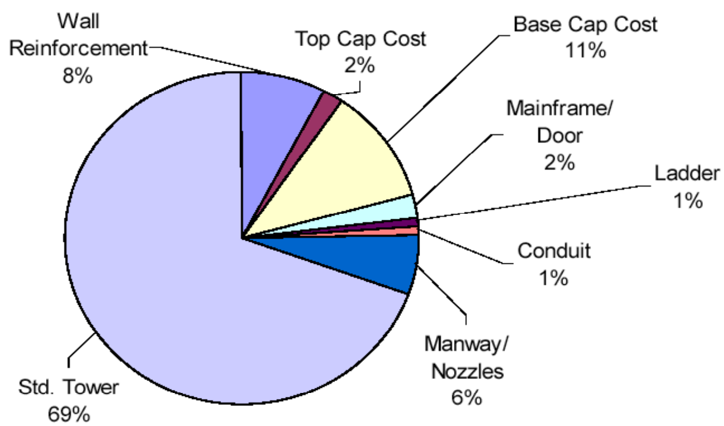
26. A sensitivity analysis was conducted on this case by examining an additional case with traditional hydrogen storage with ~3x the cost ($260,000 for 1,000 kg of storage instead of $90,000). In the sensitivity case, the hydrogen was stored in 2,100-psi storage tanks rather than within the turbine tower. The results of this sensitivity analysis showed a slight increase in the cost of stored energy ($/MWh) of around 2%. The cost of stored energy was not greatly altered since the hydrogen storage is a small cost relative to the other components of the system (fuel cell, electrolyzer, and converter).

a complete wind turbine tower and hydrogen storage system. Kottenstette and Cotrell (2003) did not address potential safety concerns with this approach, however, such as concerns about lightning strikes and other weather events, and resistance to vandalism. More research is needed to ensure that this type of storage could offer comparable safety to other alternatives.



Source: Kottenstette and Cotrell 2003

Figure 12. Cost breakdown for modifying wind turbine tower to include hydrogen storage

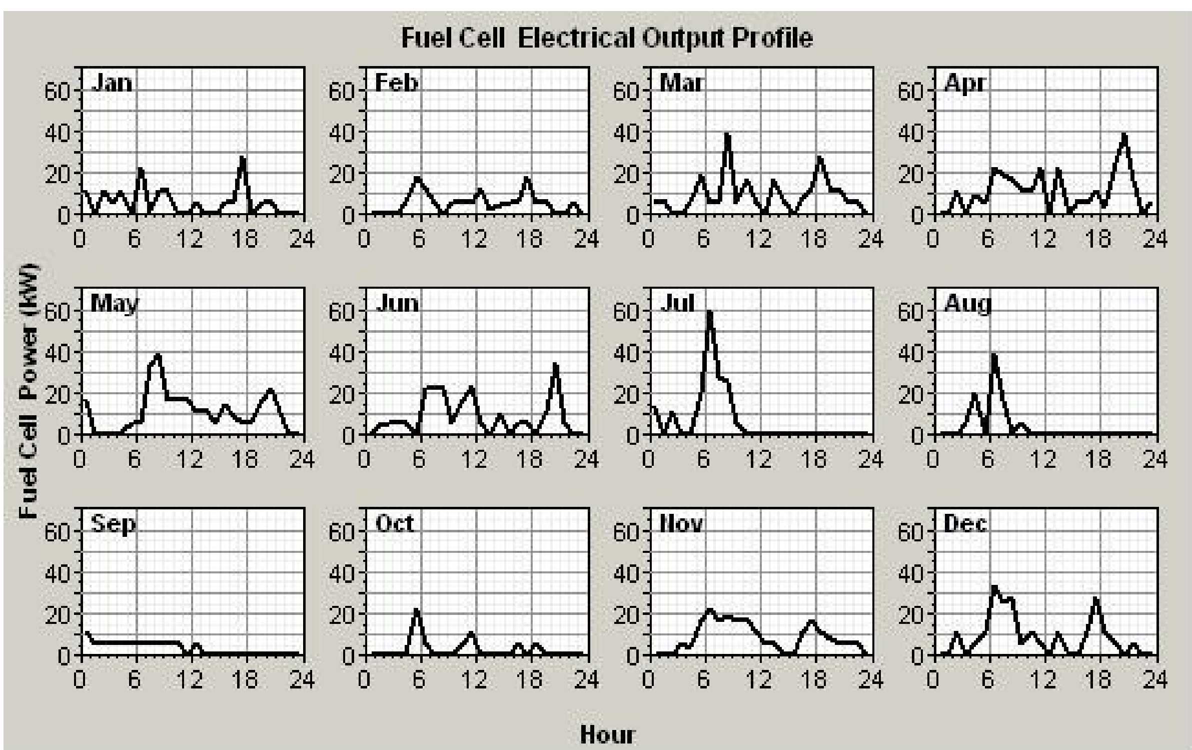


Figure 13. HOMER output for electricity provided by fuel cell system at the Tehachapi wind farm in 2020

The stored hydrogen was then supplied to an on-site fuel cell to produce electricity when load demand exceeded available wind and baseload power. The fuel cell system was sized to match the converter's output, and was designed to run at a power level with 46% efficiency in converting hydrogen to electricity. This dispatch of power from the fuel cell provides peak shaving. When hydrogen was not available for use by the fuel cell, the simulated system drew power from peaker plants and imported power, if the wind and baseload plants could not provide sufficient power. Figure 13 shows a graphical output from the HOMER model displaying the fuel cell output from the Tehachapi wind farm in 2020. Note the tendency for the fuel cell to provide power around mid-morning, just as the electricity demand increases beyond the available baseload and wind power.

Table 2 presents the key economic assumptions used for this scenario, along with sources for the input data used.

Table 2. Input data for Scenario 1—hydrogen electrolyzer/fuel cell energy storage with hydrogen storage in wind turbine towers

Variable	Year 2010	Year 2020	Source
Electrolyzer Capital Cost	$650/kW	$400/kW	H2A (Mann 2004)
Electrolyzer Installation Cost	$25,000 for 250 kW unit	$25,000 for 250-kW unit	HOMER model
Electrolyzer Maintenance. Cost	$1,000/yr for 250 kW unit	$1,000/yr for 250-kW unit	Author estimate
Electrolyzer Lifetime	15 years	20 years	Author estimate
Electrolyzer Efficiency	67% (HHV basis)	71% (HHV basis)	H2A (Mann 2004)
Hydrogen Storage Tank Capital Cost	$89,000 for 1000 kg (stored in turbine towers)	$89,000 for 1000 kg (stored in turbine towers)	Kottenstette and Cotrell 2003
Hydrogen Storage Tank Lifetime	20 years	20 years	Author estimate
Fuel Cell System Capital Cost	$1,200/kW stack plus auxiliaries (w/out power conversion)	$700/kW stack plus auxiliaries (w/out power conversion)	Author estimate (based on projected costs from Thomas et al. 2000 and other sources)
Fuel Cell System Lifetime	15,000 hours	40,000 hours	Author estimate
Fuel Cell System Efficiency	46.2% (before power conversion)	46.2% (before power conversion)	Author estimate (based on PEM FC system performance data)
Fuel Cell System Replacement Cost	$750/kW (stack only)	$400/kW (stack only)	Author estimate (based on projected costs from Thomas et al. 2000 and other sources)
Fuel Cell System Maintenance Cost	$20/kW-yr	$15/kW-yr	Author estimate

4.4.2. Scenario 2: Off-site hydrogen production for vehicle refueling

The second scenario involved off-site production facilities for hydrogen-powered vehicle refueling consisting of an electrolyzer, a hydrogen compressor, and a high-pressure hydrogen storage tank. It is important to note that this scenario is speculative in that the commercialization of hydrogen-powered vehicles is far from assured at this point. There are considerable private- and public-sector efforts to commercialize these vehicles, and billions of dollars have been spent on research and development, but key technical and economic barriers remain. These barriers include the cost and durability of fuel cell power systems, issues with hydrogen storage on board vehicles, and the lack of a hydrogen-refueling infrastructure.[27]

Our system was assumed to transmit excess wind electricity for powering an off-site electrolyzer located close to hydrogen load centers, such as hydrogen fueling stations, with the key assumption being that hydrogen was mainly being produced off-peak when transmission capacity was available. In revisiting this assumption after completing the analysis, our modeling results showed that this assumption appeared to be reasonable for most cases, but during certain times of year, transmission constraints may be an issue depending on the level of transmission connected to the wind farm. For example, Figure 14 shows the periods when we model the electrolyzer to be operating to produce hydrogen from electricity generated at the Tehachapi wind farm in 2020. For most of the year, hydrogen was being produced during off-

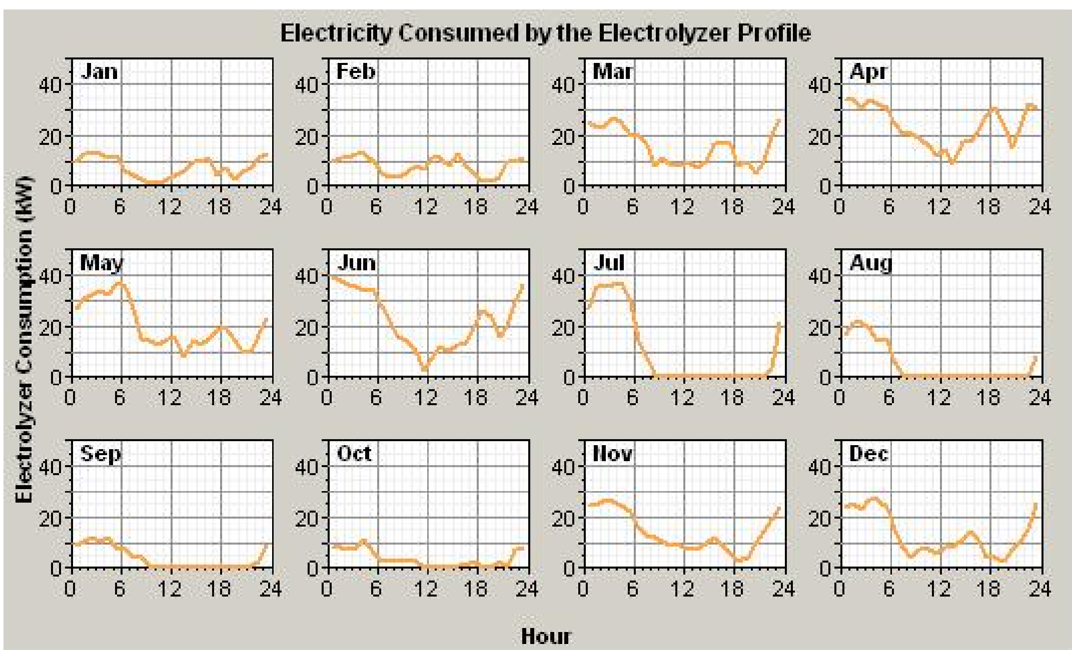


Figure 14. Operation of electrolyzer powered by excess wind power from Tehachapi wind farm to produce hydrogen in 2020

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27. See National Research Council (2004), a recent National Academy of Science study, for more on the commercialization challenges for hydrogen-powered vehicles.

peak times when transmission of the excess electricity to hydrogen load centers was unconstrained. However, there were periods where hydrogen was being produced during peak electricity use periods, and this may be difficult at the remote site assumed in this analysis due to transmission congestion during these periods.

After being produced, the hydrogen was compressed at the fueling station to feed the hydrogen into high-pressure (6,000 psi) storage tanks. We assumed that this renewable hydrogen production and storage system was integrated into existing hydrogen refueling stations that included hydrogen-dispensing equipment. Thus, the results for costs in this case are the *marginal costs* associated with expanding an existing hydrogen dispensing facility to accommodate additional wind power–produced hydrogen. We further assumed that the hydrogen was utilized within a short time frame (on the order of a day or two), thus allowing for smaller hydrogen tanks than otherwise would be required under a longer-term storage scenario. Table 3 presents the key economic assumptions used for this second scenario, along with sources for the input data used.

Table 3. Input data for Scenario 2—hydrogen from wind power for sale to hydrogen-powered vehicles

Variable	Year 2010	Year 2020	Source
Electrolyzer Capital Cost	$650/kW	$400/kW	H2A (Mann 2004)
Electrolyzer Installation Cost	$25,000 for 250-kW unit	$25,000 for 250-kW unit	HOMER model
Electrolyzer Maintenance Cost	$1,000/year for 250-kW unit	$1,000/year for 250-kW unit	Author estimate
Electrolyzer Lifetime	15 years	20 years	Author estimate
Electrolyzer Efficiency	67% (HHV basis)	71% (HHV basis)	H2A (Mann 2004)
Hydrogen Storage Tank Capital Cost	$323,000 for 1000 kg (6,000 psi cascade)	$296,000 for 1000 kg (6,000 psi cascade)	H2A (Mann 2004)
Hydrogen Storage Tank Lifetime	20 years	20 years	Author estimate
Compressor Capital Cost	$26,913 x ($H_2$ flow rate in kg/hr)$^{0.5202}$	$22,876 x ($H_2$ flow rate in kg/hr)$^{0.5202}$	Directed Technologies, Inc.

4.4.3. Scenario 3: Solid-state (lead acid) battery storage

The third scenario involved a solid-state battery storage system consisting of Trojan model LP-16 lead acid batteries. The specifications for this battery were provided within the HOMER model. This system utilized excess wind electricity to charge the battery modules. This battery system supplied electricity if the battery was charged above its minimum state of charge and when the wind and baseload power generated was insufficient to meet load demand. When available, battery power provided some peak shaving, instead of drawing power from peaker plants and imports. Table 4 presents the key economic assumptions used for this scenario, along with sources for the input data used.

Table 4. Input data for Scenario 3—energy storage for wind power with conventional lead acid batteries

Variable	Year 2010	Year 2020	Source
Lead Acid Battery Capital Cost	$116/kWh	$116/kWh	Price quote from Trojan battery vendor
Battery Round-trip Efficiency	85%	85%	HOMER
Battery Cycle Life	Varies with depth of discharge	Varies with depth of discharge	HOMER
Battery Maintenance Cost	$29/kWh per year	$29/kWh per year	Author estimate

4.4.4. Scenario 4: Flow (zinc bromine) battery storage

The final scenario involved a flow battery storage system consisting of zinc bromide electrolyte batteries manufactured by ZBB Energy. ZBB Energy provided the specifications and performance characteristics for this battery (Lex 2004). Like the solid-state battery, the flow battery modules were charged by excess wind power. The flow batteries supplied power when there was insufficient wind and baseload power and as long as they were charged, providing some peak shaving. The flow batteries can operate to a zero state of charge without degradation. The flow battery storage system provided more output than the solid-state battery system with its better round-trip efficiency, thereby improving upon the peak-shaving characteristics of the battery storage systems. Table 5 presents the key economic assumptions used for this scenario, along with sources for the input data used.

Table 5. Input data for Scenario 4—energy storage for wind power with zinc bromine flow batteries

Variable	Year 2010	Year 2020	Source
Zinc Bromine Battery Capital Cost	$400/kWh	$300/kWh	Norris et al. 2003 for 2010, Author estimate for 2020
Battery Round-trip Efficiency	77%	77%	Lex 2004
Battery Cycle Life	2,000 cycles	2,000 cycles	Norris et al. 2003
Battery Maintenance Cost	$20/kWh per year	$20/kWh per year	Lex 2004

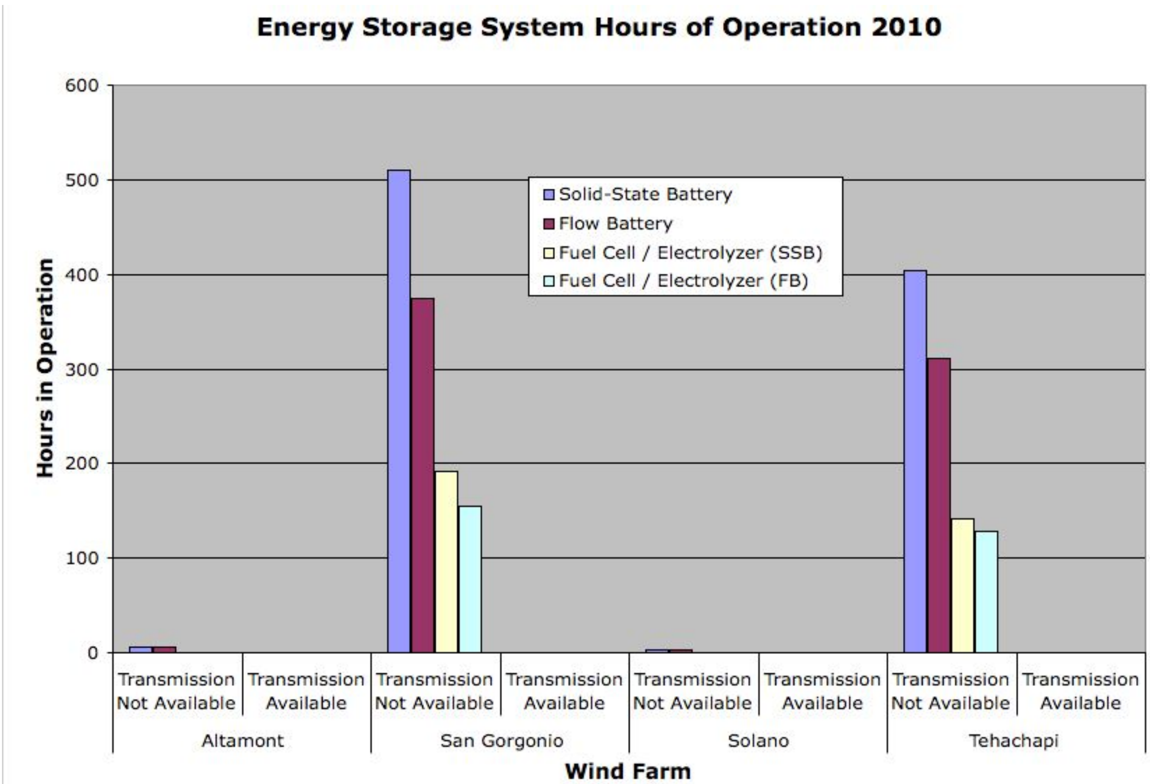
4.5. Modeling Results: Energy Storage Utilization Rates

HOMER model runs showed that utilization rates of the four energy storage systems evaluated in this report varied dramatically from one technology to the next. Figure 15 shows the number of hours the energy storage systems were providing electricity. In this figure and the ones to follow, hours of operation are shown for each case study site and for those times when transmission between Northern and Southern California was available (therefore, storage was not often needed) and when transmission was not available (so that storage was needed in some cases).

In both the 2010 and 2020 scenarios, the solid-state battery system provided the most hours of electricity followed by the flow battery and then the electrolyzer/fuel cell. In addition to factors related to the wind resource and the economics of the energy storage technologies, this outcome can be explained by the solid-state battery system's lower electricity output per hour than the other storage systems. In other words, when the system is fully charged, it takes the solid-state battery longer to discharge the stored energy compared to the flow battery and electrolyzer/fuel cell.

Figure 16 shows the number of hours the energy storage systems were electrically recharging or electrochemically producing hydrogen. In 2010, each energy storage system was charging for the same number of hours except for the electrolyzer/fuel cell sized to match the output of the flow battery. This outcome was a result of this system being unable to utilize the excess electricity due to the hydrogen tank reaching capacity. In 2020, the electrolyzer/hydrogen production system was in operation for the most hours, followed by the flow battery, the solid-state battery, and then the electrolyzer/fuel cell. The hydrogen production system was able to utilize excess electricity in all hours, since it had no storage capacity constraint, unlike the energy storage systems.

Figure 17 shows the energy storage system utilization level in terms of the energy provided by the system compared with the maximum theoretical level (i.e., at full charge and discharge power operation) over a full 8,760-hour modeled year. For the hydrogen production system, this figure is the percentage of time that the system was producing hydrogen. As shown in the figures and discussed further below, the modeled level of energy storage system utilization is relatively low given the data, models, and assumptions used in this analysis. However, the usage increases significantly between 2010 and 2020 due to the greater level of wind penetration, especially in Southern California. Figure 17 also shows that in both 2010 and 2020, the hydrogen production system was utilized significantly more than the other energy storage systems. This stems from the fact that the hydrogen production system had no storage capacity constraint, since the modeling assumed that the hydrogen would be used by hydrogen-powered vehicles at a rate that would not cause a "bottleneck" effect in storage. The flow battery was the most utilized of the energy storage systems providing electricity. This system's ability to discharge more rapidly, combined with a relatively high conversion efficiency, allowed the flow battery to have higher utilization rate than the solid-state battery and the electrolyzer/fuel cell.



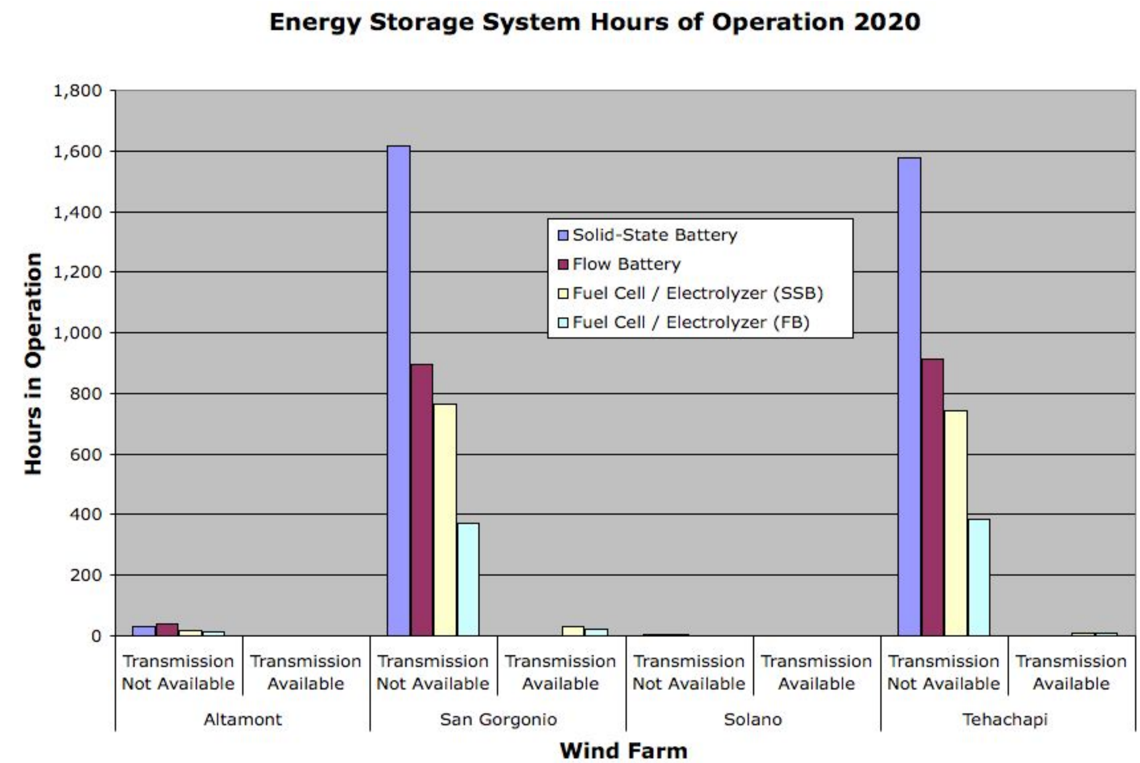
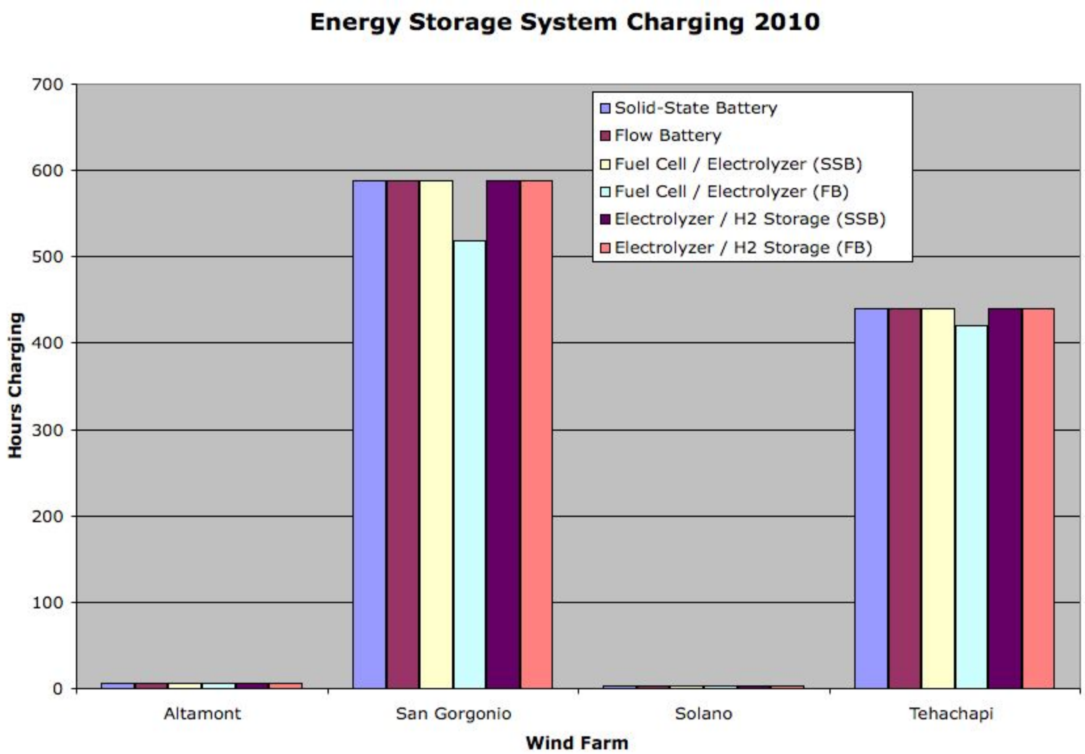


Figure 15. Number of hours the energy storage system is providing electricity



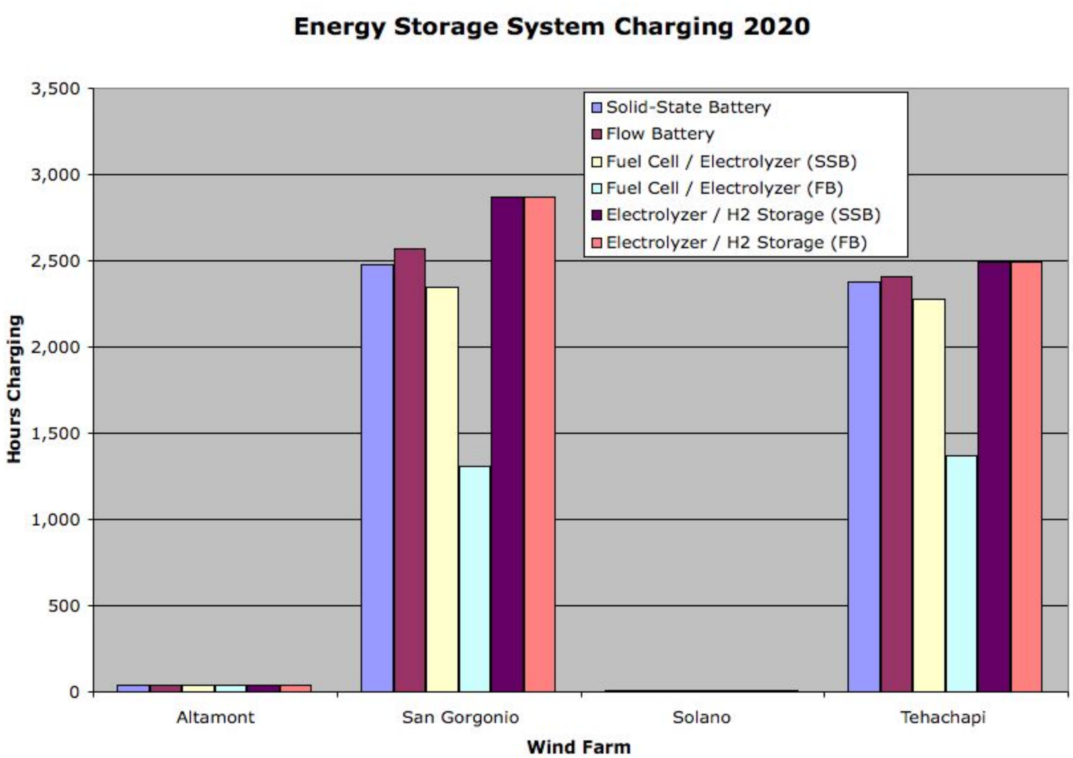
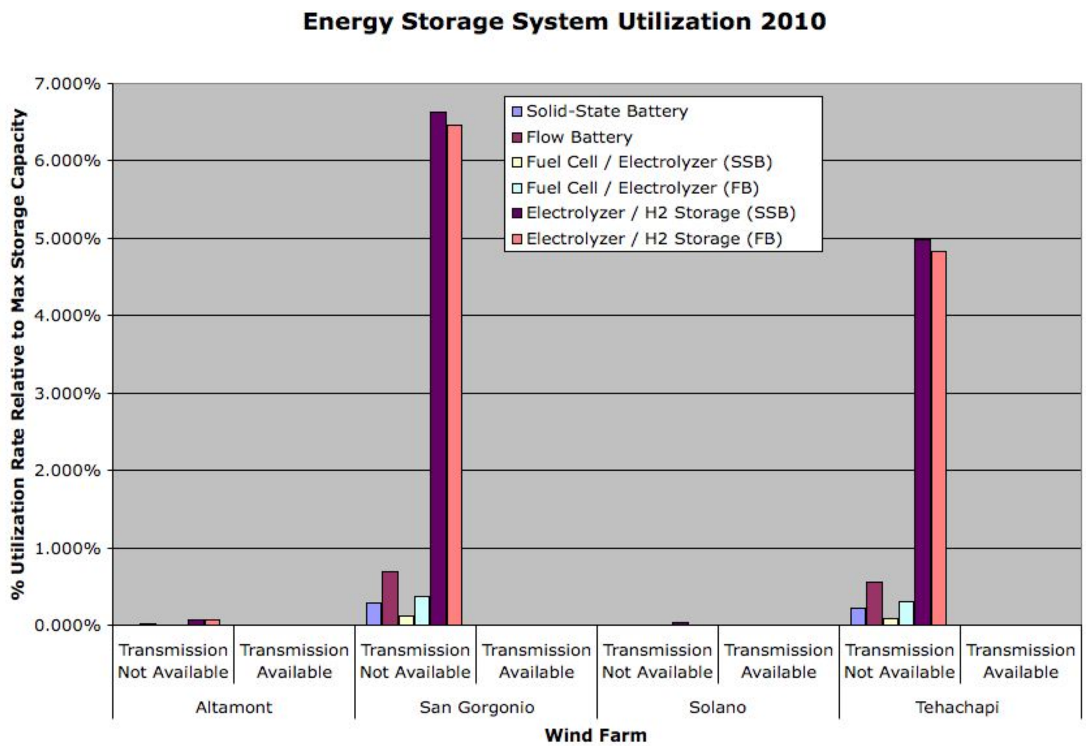


Figure 16. Number of hours the energy storage system is charging or H_2 production system is in operation



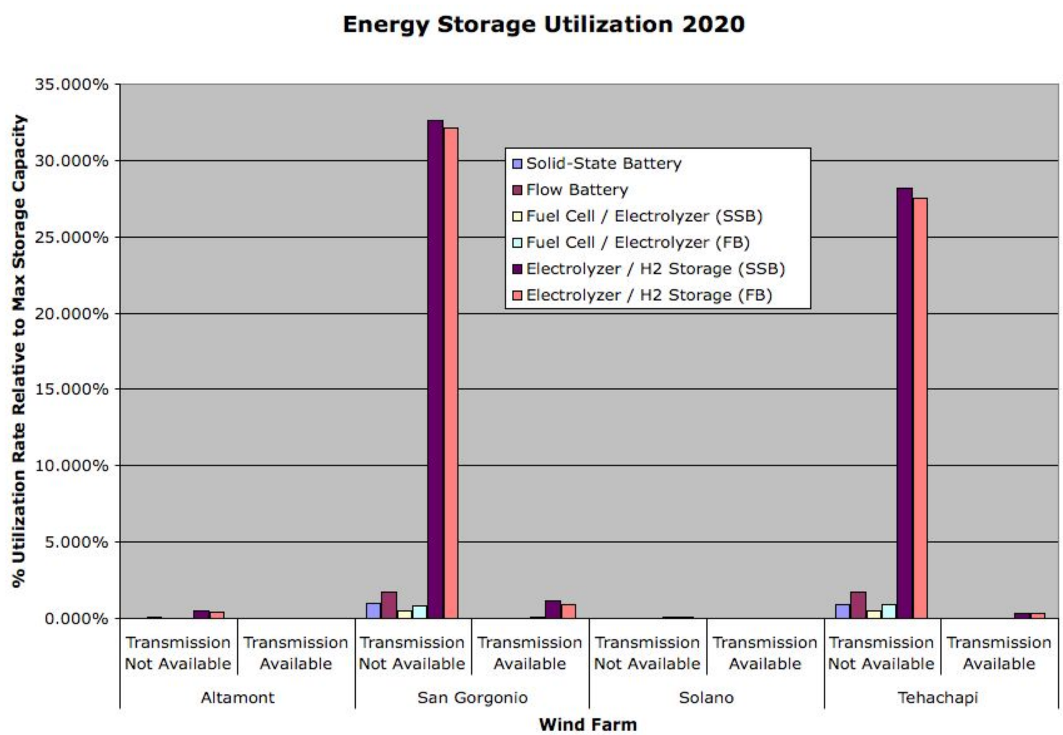


Figure 17. Energy storage system utilization relative to maximum capacity of storage system

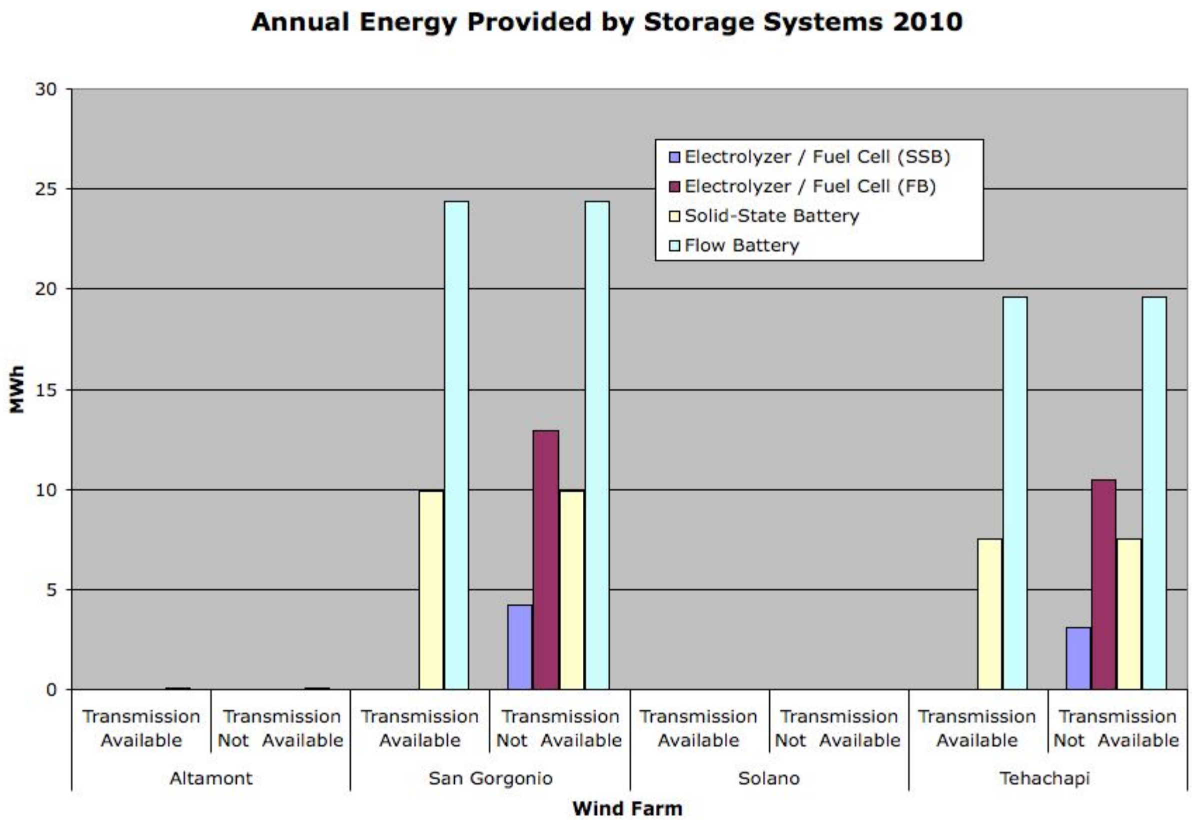
4.6. Modeling Results: Economic Comparison of Energy Storage Systems

The HOMER model calculated the annualized cost of the components of the specified energy system, taking into account the initial capital cost, annual maintenance costs, and replacement cost (if replacement was necessary). The cost estimates from the four scenarios were compared along with electricity output and storage to determine which energy storage system provided the most cost-effective solution. Utilizing the outputs from HOMER, two key metrics were calculated: (1) the net present cost (NPC) of the energy storage systems, and (2) the annual cost of energy storage ($/MWh). The annual cost of stored energy results are more meaningful for purposes of comparison, so we primarily focused on these $/MWh results as well as additional metrics such as the number of hours of system operation per year and the overall impact of the costs of energy storage in affecting intermittent renewables market bid prices.

During the modeling of the different energy storage systems, we encountered a trend within HOMER, in the case of battery storage with available grid transmission, to send available excess electricity to charge the batteries rather than transmit for grid sales. With the electrolyzer/fuel cell, HOMER did the opposite and sent the available excess electricity for transmission rather than supplying the electrolyzer. These default settings could not be altered, and they eliminated the possibility of direct comparison between battery systems and the electrolyzer/fuel cell in the case of available transmission. However, comparisons within the same energy storage technologies were still feasible in the instances of constrained transmission (i.e., no available transmission between Southern and Northern California).

With 10% wind penetration in 2010 (Figure 18), the modeling forecasts limited utilization for the energy storage systems in the cases with available electricity transmission. Under these conditions, the electrolyzer/fuel cell system was not utilized. Comparing the solid-state battery and the flow battery, the flow battery system produced the most electricity, nearly tripling the output of the solid-state battery system in the Southern California wind farms. In the cases involving no transmission, the fuel-cell electrolyzer system was utilized in the Southern California sites, but not in the Northern California sites, where there was insufficient excess electricity to power the electrolyzer. In all the transmission-constrained cases, the flow battery delivered the most electricity from each location, followed by the "FB" electrolyzer/fuel cell (sized to match the output of the flow battery system), the solid-state battery, and then the "SSB" electrolyzer/fuel cell (sized to match the output of the solid-state battery system).

The cost per megawatt-hour of stored electricity is found in Table 6. At the two Southern California wind sites, the flow battery delivered the lowest cost per MWh of electricity, followed by the "FB" electrolyzer/fuel cell system. The solid-state battery and the "SSB" electrolyzer/fuel cell system displayed similar costs (in the case with no available transmission). In the Northern California sites, the flow battery had a significant cost advantage over the solid-state battery. Despite having the highest annualized cost, the flow battery had the lowest cost per MWh stored and delivered in each case due to its higher rate of energy intake and return. The rapid cycling characteristic of this technology allowed the flow battery to take in more of the excess electricity when it was available and placed greater amounts of electricity on the grid when necessary, compared to the solid-state battery or the electrolyzer/fuel cell.



Note: SSB = system sized to match solid-state battery system output;
FB = system sized to match flow battery system output

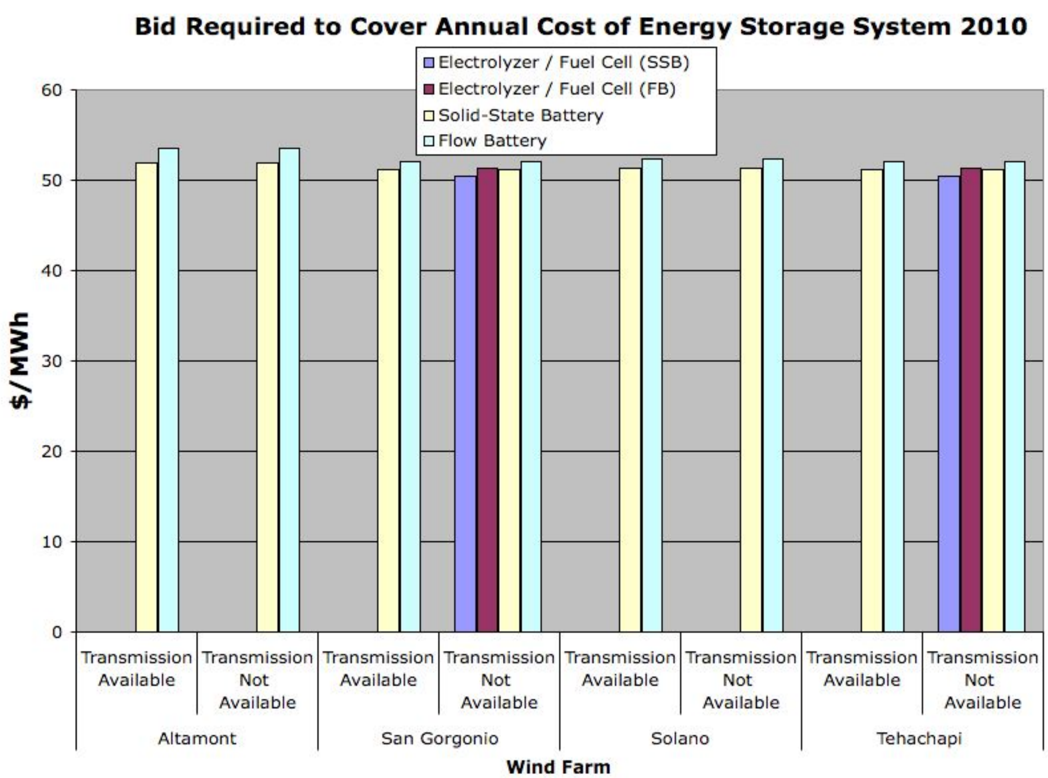
Figure 18. 2010 scenario—annual energy provided by energy storage systems (MWh)

Table 6. 2010 scenario—annual cost of stored energy ($/MWh)

	Altamont (N. CA)		San Gorgonio (S. CA)		Solano (N. CA)		Tehachapi (S. CA)	
Transmission Possible?	Yes	No	Yes	No	Yes	No	Yes	No
Electrolyzer/Fuel Cell (SSB)	N/A	N/A	N/A	$2,277	N/A	N/A	N/A	$3,075
Electrolyzer/Fuel Cell (FB)	N/A	N/A	N/A	$2,134	N/A	N/A	N/A	$2,616
Solid-State Battery	$241,056	$241,056	$2,298	$2,298	$463,594	$463,594	$3,033	$3,033
Flow Battery	$121,723	$121,723	$1,728	$1,728	$241,318	$241,318	$2,151	$2,151

Note: N/A = Not applicable
SSB = System sized to match solid-state battery system output
FB = System sized to match flow battery system output

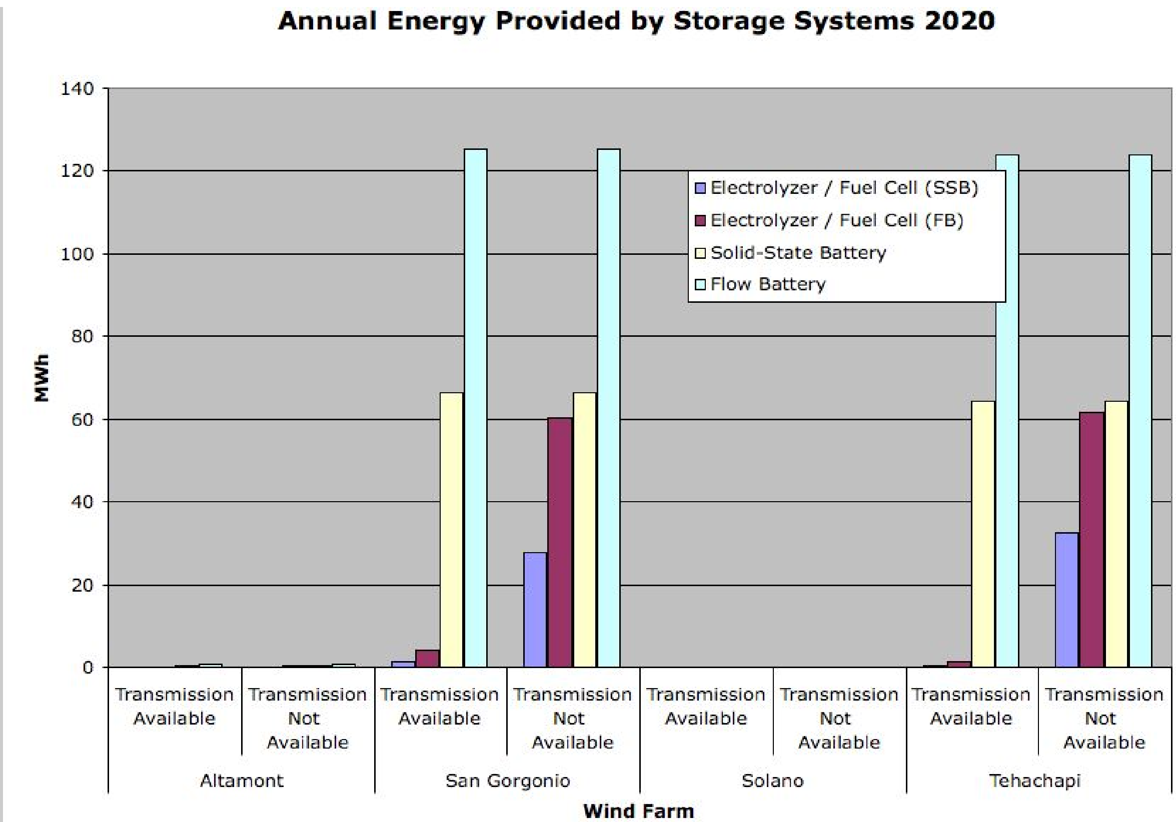
Another feature of energy storage systems is their ability to "firm up" wind power to enhance wind's position in an electricity market bidding setting. In this example, bids required to cover the annualized cost of the energy storage system are based on the forecast bid for wind power (assumed to be $50/MWh) multiplied by annual wind output plus the annualized cost of the energy storage systems averaged over the combined annual electricity provided by the wind and energy storage system. As shown in Figure 19, comparing the energy storage systems in 2010 based on this calculation in the Southern California sites, the "SSB" electrolyzer-fuel cell system required the lowest bid to recover costs followed by the solid-state battery, the "FB" electrolyzer/fuel cell system, and then the flow battery. This finding is a result of the lower cost of the relatively small "SSB" electrolyzer/fuel cell system. In Northern California, where the electrolyzer/fuel cell systems did not operate, the solid-state battery required a lower bid to recover annual costs than the flow battery system. The variation in the bid prices was relatively small, since the amount of wind energy far exceeded the energy provided by the storage systems.



Note: SSB = system sized to match solid-state battery system output;
FB = system sized to match flow battery system output

Figure 19. 2010 scenario—bid required to cover annual cost of energy storage system assuming a no-storage system bid of $50/MWh ($/MWh)

When wind penetration was assumed to increase to 20% in 2020 (Figure 20), energy storage system utilization increased several-fold at the Southern California sites. As with the 2010 scenario, the flow battery led with the greatest quantity of stored electricity delivered, followed by the “FB” electrolyzer/fuel cell system, the solid-state battery, and then the “SSB” electrolyzer/fuel cell system. The comparison of the electrolyzer/fuel cell case with “transmission” and “no transmission” cases showed that, with transmission, storage system utilization dropped dramatically, as the excess electricity was prioritized for transmission. At this penetration level, the Northern California sites began to utilize the electrolyzer/fuel cell system during the transmission-constrained case but at much lower levels than the Southern California sites. Similar to the 2010 scenario, the flow battery stored and delivered the most energy.



Note: SSB = system sized to match solid-state battery system output;
FB = system sized to match flow battery system output

Figure 20. 2020 scenario—annual energy provided by energy storage systems (MWh)

In the 2020 scenario (Table 7), projected decreases in electrolyzer and fuel cell costs, along with the increased efficiency of the electrolyzer, combined to drive the cost ($/MWh) of energy stored by the “SSB” electrolyzer/fuel cell system down to the lowest cost among the four storage systems in the “constrained transmission” Southern California sites. However, the “FB” electrolyzer/ fuel cell system had the highest cost among the energy storage systems. In the Northern California sites, where utilization of all the storage systems was much lower and energy storage in general looked much less attractive, the flow battery continued to hold the lowest cost per MWh of stored energy.

The bids required to cover the annual cost of energy storage systems in 2020 showed a similar relative price to the 2010 scenario with the "SSB" electrolyzer/fuel cell system requiring the lowest bid followed by the solid-state battery, the "FB" electrolyzer/fuel cell system, and then the flow battery. These results are shown in Figure 21.

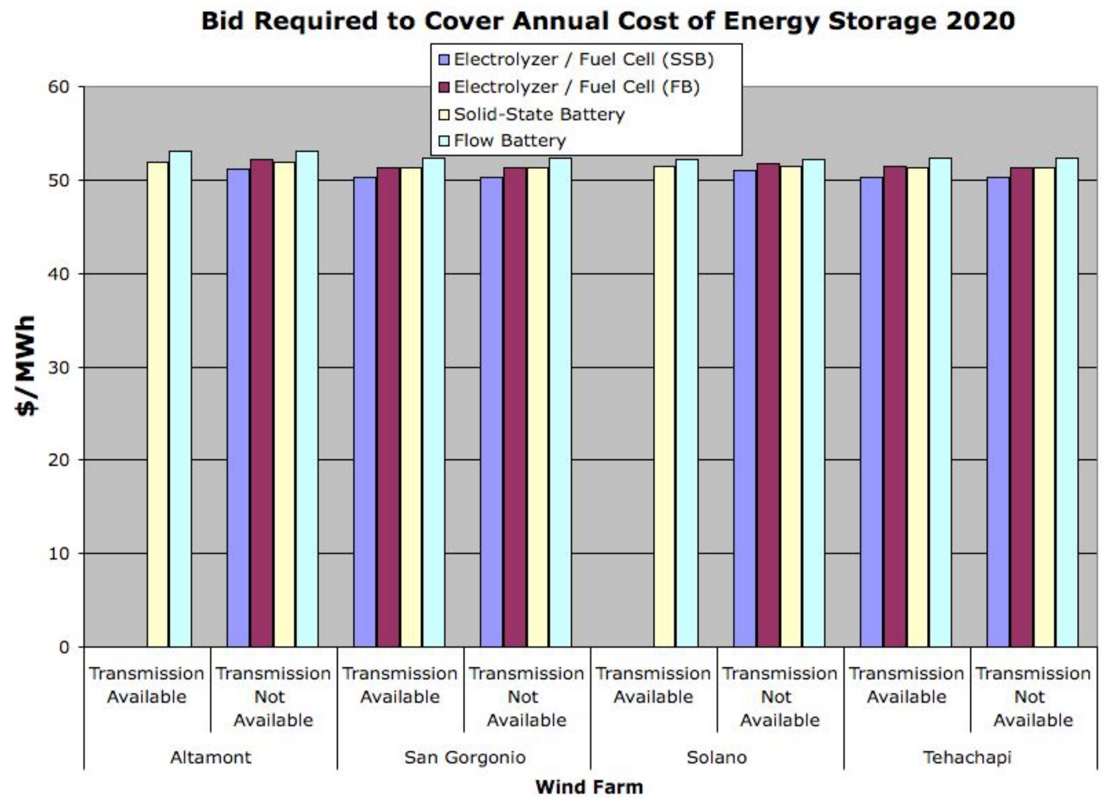
Table 7. 2020 scenario—annual cost of stored energy ($/MWh)

	Altamont (N. CA)		**San Gorgonio (S. CA)**		**Solano (N. CA)**		**Tehachapi (S. CA)**	
Transmission Possible?	Yes	No	Yes	No	Yes	No	Yes	No
Electrolyzer/Fuel Cell (SSB)	N/A	$59,241	$9,184	$476	N/A	$758,167	$32,434	$411
Electrolyzer/Fuel Cell (FB)	N/A	$32,158	$12,615	$927	N/A	$368,238	$42,227	$905
Solid-State Battery	$33,250	$33,250	$829	$829	$247,250	$247,250	$846	$846
Flow Battery	$17,523	$17,523	$783	$783	$127,042	$127,042	$788	$788

Note: N/A = Not applicable
SSB = System sized to match solid-state battery system output
FB = System sized to match flow battery system output

Based on these 2010 and 2020 scenarios, it appears that the higher the wind penetration, the more competitive the electrolyzer/fuel cell system becomes. In 2010, the Northern California sites showed no utilization of the electrolyzer/fuel cell system, while the greater penetration in the Southern California sites allowed the "SB" electrolyzer/fuel cell system to be a cost-competitive storage system. With lower projected capital, replacement, and maintenance costs for the "SB" electrolyzer/fuel cell system in 2020, this system in Southern California delivered stored electricity at nearly half the cost of the battery storage systems.

Another aspect of the modeling results involved the cost and performance differences between the "FB" electrolyzer/fuel cell and the "SSB" electrolyzer/fuel cell systems. The cost of energy stored decreased in low-energy-storage scenarios (e.g., 2010 and Northern California 2020) in moving from the "SSB" electrolyzer/fuel cell to the "FB" electrolyzer/fuel cell system. In the high-energy-storage scenarios (e.g., Southern California 2020), the cost of energy stored was higher for the "SSB" electrolyzer/fuel cell system compared to the "FB" electrolyzer/fuel cell system. This likely resulted from the increased cost of the higher-capacity fuel cell, converter, and electrolyzer outweighing the increased electricity storage. This demonstrates an increasing return to scale as energy storage increases, up to a point after which the scale returns decrease.



Note: SSB = system sized to match solid-state battery system output;
FB = system sized to match flow battery system output

Figure 21. 2020 scenario—bid required to cover annual cost of energy storage system assuming a no-storage system bid of $50/MWh ($/MWh)

In addition, the bids required to cover the annualized costs for the flow battery and solid-state battery systems increased in 2020 in the Southern California sites, because the electricity from energy storage became a larger portion of the energy bid by the wind farms. Higher costs resulted from the required battery replacements that were a consequence of the high utilization of the energy storage systems. In Northern California, the solid-state battery bids remained the same at Altamont from 2010 to 2020 (due to energy storage system costs remaining the same) while the flow battery bids decreased at both Altamont and Solano due to a projected decrease in system cost in 2020. The bids for the solid-state battery system at Solano increased from 2010 to 2020 because the energy system costs doubled, but the wind turbine energy did not exactly double. However, if the 2020 Solano wind power output were scaled up to be exactly twice that of 2010, the price of the bids in 2010 and 2020 would be the same.[28] The bids required to cover

28. The HOMER model input for the number of turbines is limited to whole numbers. As mentioned in Section 4.3 of this report, the wind turbine output was rated down by a factor of eight to "fine tune" the percentage of wind penetration. The numbers input into the model are to be multiplied by 1,000 and then divided by eight to get the actual number of wind turbines. For example, 1% wind penetration at the

the additional cost of the electrolyzer/fuel cell systems decreased from 2010 to 2020 as a result of lower projected costs for fuel cells and electrolyzers in 2020.

We note that these estimates of the increase in bid price needed to cover the costs of storage are similar in magnitude to and generally somewhat lower than estimates of the costs of wind integration in various settings. These costs depend on the level of wind power penetration and the nature of the grid and, based on the results of various international studies, would seem to range from about $2.50 to $4.00 per MWh with 10% penetration up to about $3.50 to $5.50 per MWh at 20% penetration (Milborrow 2004b; Utility Wind Interest Group 2003). The energy storage systems examined here would not necessarily completely solve the problem of integrating wind power, however, depending on how the systems were sized and operated. Along with the relatively high costs of stored electricity per MWh that we estimate even in the most attractive cases, this suggests that multiple value streams may need to be identified for energy storage systems to be economically competitive in the California setting.

4.6.1. Electrolyzer/fuel cell energy storage vs. hydrogen production

Comparing the two hydrogen systems, the off-site hydrogen production facility compared favorably in terms of cost to the electrolyzer/fuel cell energy storage system in both 2010 and 2020 time frames (Tables 8 and 9). The NPC of the hydrogen-producing system was less than the NPC of the electrolyzer/fuel cell system in all cases despite higher costs for hydrogen

Table 8. 2010 scenario—annual cost avoided from electricity production or annual revenue generated from H_2 production

	Altamont (N. CA)		San Gorgonio (S. CA)		Solano (N. CA)		Tehachapi (S. CA)	
Transmission Possible?	Yes	No	Yes	No	Yes	No	Yes	No
Electrolyzer/Fuel Cell (SSB)	N/A	N/A	N/A	$273,000	N/A	N/A	N/A	$201,500
Electrolyzer/Fuel Cell (FB)	N/A	N/A	N/A	$838,500	N/A	N/A	N/A	$682,500
Hydrogen Production (SSB)	N/A	$2,838 (568 kg)	N/A	$1,380,000 (276,000 kg)	N/A	$950 (190 kg)	N/A	$1,010,000 (202,000 kg)
Hydrogen Production (FB)	N/A	$10,100 (2,020 kg)	N/A	$5,230,000 (1,046,000 kg)	N/A	$3,450 (690 kg)	N/A	$3,785,000 (757,000 kg)

Note: N/A = Not applicable

SSB = system sized to match solid-state battery system output

FB = system sized to match flow battery system output

Solano site in 2010 amounts to seven turbines input into HOMER with 875 turbines being the actual number (1.06% penetration), and 2% wind penetration in 2020 amounts to thirteen turbines input into HOMER with 1,625 turbines being the actual number (1.97% penetration). This resulted in a discrepancy in the price of the bids between 2010 and 2020 because the sum of the bid price for wind power plus the energy storage system cost is divided by the wind output.

Table 9. 2020 scenario—annual cost avoided from electricity production or annual revenue generated from H_2 production

	Altamont (N. CA)		San Gorgonio (S. CA)		Solano (N. CA)		Tehachapi (S. CA)	
Transmission Possible?	Yes	No	Yes	No	Yes	No	Yes	No
Electrolyzer/Fuel Cell (SSB)	$0	$5,660	$91,000	$2,171,000	$0	$390	$25,740	$2,106,000
Electrolyzer/Fuel Cell (FB)	$0	$19,760	$273,000	$3,913,000	$0	$1,370	$84,500	$4,010,500
Hydrogen Production (SSB)	$0	$20,000 (8,000 kg)	$231,000 (92,400 kg)	$6,772,500 (2,709,000 kg)	$0	$1,825 (730 kg)	$70,750 (28,300 kg)	$5,845,000 (2,338,000 kg)
Hydrogen Production (FB)	$0	$67,500 (27,000 kg)	$725,000 (290,000 kg)	$25,782,500 (10,312,800 kg)	$0	$5,875 (2,350 kg)	$243,000 (97,200 kg)	$22,080,000 (8,832,000 kg)

Note: N/A = Not applicable

SSB = system sized to match solid-state battery system output

FB = system sized to match flow battery system output

storage. With the price of hydrogen sold to vehicles at $5.00/kg in 2010 and $2.50/kg in 2020, the hydrogen production facility generated higher revenue from hydrogen sales than the electrolyzer/fuel cell saved in terms of avoided cost of electricity in all cases. The hydrogen production scenario made even greater revenues as the electrolyzer and converter capacities were increased. However, if the electricity avoided corresponded to peak load periods and the value given to the cost of electricity was from the marginal generators during those peak periods (e.g., natural gas peaker plants), the economics of the electrolyzer/fuel cell system became somewhat more competitive with the hydrogen production system.

In addition, the levelized cost of the hydrogen production system per kilogram of hydrogen produced fell from 2010 to 2020, as the projected costs of the electrolyzer fell and more available wind energy allowed hydrogen production to increase (Table 10). The increased capacity of the "FB" hydrogen production system reduced the cost of hydrogen over the "SSB" hydrogen production system despite the additional cost of the equipment. In each instance, the cost of producing hydrogen exceeded the assumed sale price of hydrogen ($5.00 per kilogram in 2010 and $2.50 per kilogram in 2020), especially in 2010. This suggests that some subsidies for renewable hydrogen may be required to make this source of hydrogen commercially viable in the near term. We also note that these cost estimates relate to the marginal cost of adding additional hydrogen production and storage capacity to an existing station. The estimated cost of hydrogen production in Southern California in the case of no transmission was much lower in 2020 than in 2010, but this cost was still $0.50 or more per kilogram higher than the assumed prevailing sales price at that time. The availability of transmission capacity to Northern California loads dramatically increased the cost of the system per kilogram of hydrogen produced, as a result of lower hydrogen production, with much of the excess electricity shipped north instead of being converted to hydrogen.

Table 10. Levelized cost hydrogen production system ($/kg of hydrogen)

	Altamont (N. CA)		San Gorgonio (S. CA)		Solano (N. CA)		Tehachapi (S. CA)	
Transmission Possible?	Yes	No	Yes	No	Yes	No	Yes	No
2010 (SSB)	N/A	$7,241	N/A	$28	N/A	$20,005	N/A	$39
2010 (FB)	N/A	$3,147	N/A	$19	N/A	$7,379	N/A	$27
2020 (SSB)	N/A	$578	$115	$3.96	N/A	$5,716	$374	$4.58
2020 (FB)	N/A	$298	$104	$2.99	N/A	$2,778	$312	$3.48

Note: N/A = Not applicable
SSB = system sized to match solid-state battery system output
FB = system sized to match flow battery system output

4.6.2. Value of energy storage as coupled with wind power to arbitrage peak/off-peak power prices

We compared the value of energy storage utilizing peak/off-peak prices and two peak parameters—season and time of day—as variables (Table 11). The high-peak period spanned May through September with the time of day between 12 PM and 6 PM. The electricity provided by the storage systems during these times was valued at $120/MWh. The low-peak period spanned October through April with the time of day between 12 PM and 6 PM. The electricity provided during these times was valued at $70/MWh. The off-peak periods were designated as the hours between 6 PM and 12 PM (the following day) every day of the year. The electricity provided during these times was valued at $50/MWh.

We found that the annual revenues from this price structure were lower than the fixed price structure that valued all electricity provided at $65/MWh. This reflects the fact that most of the electricity was provided during off-peak times, since HOMER supplies stored energy, if available, when demand exceeds baseload plus wind power. This typically occurs in the late morning, just before peak hours come into effect. We were unable to optimize the delivery of power with regard to peak periods within the structure of HOMER, but suspect that this could improve the value proposition for energy storage, if appropriate market mechanisms were in place to allow appropriate compensation for power provided during peak demand periods.

Table 11. 2020 scenario—comparison of the annual value of stored energy: peak/off-peak price structure vs. fixed price structure

	Altamont (N. CA)		San Gorgonio (S. CA)		Solano (N. CA)		Tehachapi (S. CA)	
Peak Pricing in Place?	Yes	No	Yes	No	Yes	No	Yes	No
Electrolyzer/ Fuel Cell (SSB)	$4,350	$5,660	$1,936,000	$2,171,000	$300	$390	$1,877,000	$2,106,000
Electrolyzer/ Fuel Cell (FB)	$15,200	$19,760	$3,189,000	$3,913,000	$1,050	$1,370	$3,369,000	$4,010,500
Solid-State Battery	$13,000	$16,900	$4,180,000	$4,316,000	$1,200	$1,560	$3,900,000	$4,186,000
Flow Battery	$39,300	$51,090	$6,803,000	$8,145,000	$3,600	$4,680	$6,842,000	$8,054,000

Note: SSB = system sized to match solid-state battery system output
FB = system sized to match flow battery system output

4.7. Modeling Results: Sensitivity Analysis of Smaller Energy Storage Systems

A sensitivity analysis was conducted to evaluate the economic impacts of reducing the capacity of the energy storage systems from 10% to 3%. This analysis showed that despite a reduction in the cost of the energy storage system, the cost of stored energy ($/MWh) did not decrease dramatically and in many cases increased slightly. This is because the HOMER model simulations typically revealed periods with relatively high levels of excess power, meaning smaller systems were not shown to be better utilized than the larger systems. In fact, costs were estimated to be slightly higher due to the balance-of-plant costs[29] associated with the energy storage system remaining nearly the same despite the decrease in energy storage capacity.

We expect that a finer-resolution model would identify additional brief periods of relatively low excess power, and potentially other opportunities for energy storage systems to provide value (such as helping to compensate for wind forecasting errors on a real-time basis). To the extent these additional opportunities required relatively modest amounts of power to be absorbed and discharged, they would be expected to improve the economic attractiveness of relatively small systems.

29. *Balance of plant* consists of auxiliary equipment associated with energy storage systems, such as power electronics, wiring, circuit protection equipment, etc.

5.0 Potential Environmental Impacts of Energy Storage Systems

In general, energy storage offers the possibility of improving the environmental impacts of electricity production by potentially making intermittent renewable resources more attractive and competitive. Beyond that general type of impact, however, there are also potential environmental impacts associated with the use of specific storage systems themselves. Furthermore, the potential production of hydrogen as a vehicle fuel from intermittent renewables involves environmental issues and trade-offs.

In this section of the report, we first review the potential environmental impacts of various energy storage systems. Second, we discuss environmental considerations associated with the use of energy storage as coupled with wind power in California. Finally, we examine the environmental issues associated with the production of hydrogen as a vehicle fuel from intermittent renewables.

5.1. Environmental Impacts of Energy Storage Systems

Energy storage systems are, for the most, part self-contained systems that rarely involve significant emissions to air, water, or soil media. Emissions and other environmental impacts associated with system *manufacture* can be significant, however, particularly for battery systems where direct lead and sulfur dioxide (SO_2) emissions are of concern and where high electricity requirements for manufacturing (particularly for nickel smelting for nickel metal hydride batteries) produce significant emissions. Direct emissions from battery manufacture are tightly controlled in the U.S., but may be less well controlled in other countries.

Table 12 presents a qualitative assessment of the potential environmental impacts of various energy storage systems that may be practical for use in conjunction with intermittent renewable energy resources. As shown in the table, most energy storage systems are relatively benign from an environmental standpoint. Manufacturing emissions associated with battery systems are the primary impacts of concern, along with potential toxic emissions of bromine from zinc bromine battery systems. We note that these direct bromine emissions are only possible in the event of what we expect to be unlikely failures in battery vessel/containment systems and, therefore, are unlikely to be a serious issue for these types of storage systems.

Table 12. Qualitative environmental impacts of energy storage systems

Energy Storage System	Manufacturing Impacts	Operational Impacts			Disposal Impacts
		Air	Water	Soil	
Compressed Air	Relatively low	Not significant, except from associated combustion turbine	Not significant	Not significant	Relatively low
Flywheels	Relatively low	Not significant	Not significant	Not significant	Relatively low
Hydrogen Electrolyzer/Fuel Cell	Relatively low depending on technology and materials used	Not significant	Likely not significant—discharge water can have low pH	Not significant	Relatively low, depending on technology and materials
Lead Acid Battery	Lead and SO_2 emissions can be significant but are tightly controlled in U.S.	Not significant	Not significant	Not significant	Lead contamination and sulfuric acid electrolyte are of significant concern but disposal relatively well regulated in the U.S.
Nickel Metal Hydride Battery	Relatively high air emissions from electricity needed for nickel smelting (can be reduced by battery recycling) as well as possible direct SO_2 emissions	Not significant	Not significant	Not significant	Relatively low compared to other battery technologies
Pumped Hydro	Relatively low	Not significant if pumping energy comes from clean renewable source	Not significant	Not significant	Relatively low
Zinc Bromine Flow Battery	Relatively low compared with other battery types	Bromine leak locally toxic	Bromine leak locally toxic	Likely not significant	Relatively low with electrolyte less toxic than most other batteries and recyclable plastic components

5.2. Environmental Considerations for Energy Storage and Wind Power

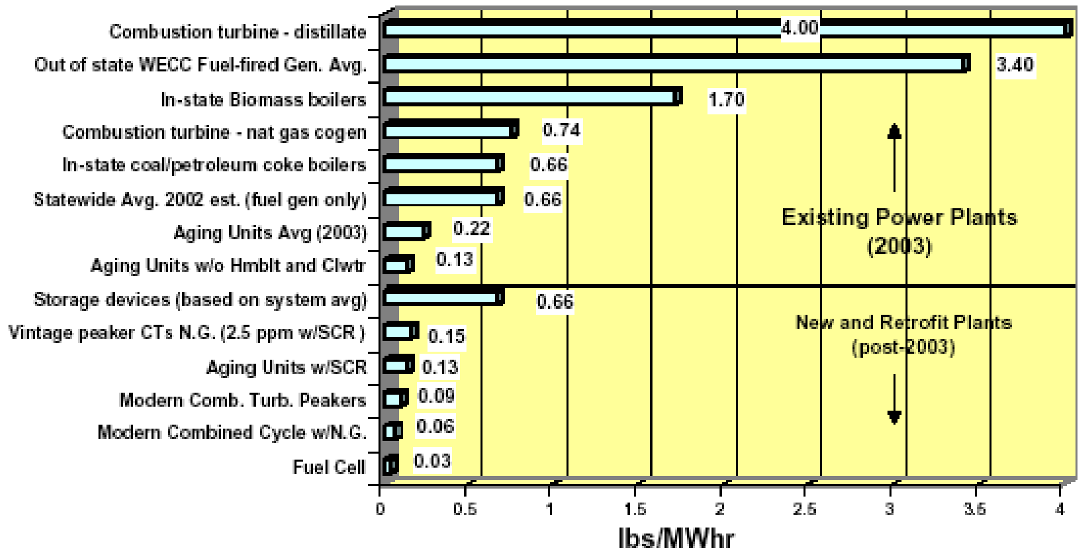
The environmental implications of including energy storage to improve the capacity factor and dispatch profile of wind energy in California are difficult to assess because of several important complications. These include the complex mix of power generation in California, uncertainty in which types of power plants are marginal at which times, and regional variations around the state with regard to electricity generation technology mixes.

At the simplest level, if energy storage allows wind power capacity factors to increase and for greater amounts of conventional generation to be displaced, environmental benefits are sure to accrue due to the conventional power plant emissions that are displaced. The amount of displaced emissions will depend on the specific generators that are displaced by the extra wind power that can be brought online. This would be the case if some wind power that is produced off peak is not accepted into the utility grid at some hours of the year in the absence of storage, due to the need for baseload plants to operate uninterrupted during these periods.

If energy storage coupled with wind power allows power that would be produced off peak to be delivered onto the grid at on-peak times, then environmental benefits would accrue because more conventional generation is being displaced. In this case, the environmental benefits would again vary depending on which specific generation sources are marginal during those periods and that are being displaced by the wind power that has been stored and dispatched during the peak demand periods.

Figure 22 shows that power plant emissions vary significantly in California, even for natural-gas-fired plants. Modern combined-cycle plants running on natural gas produce about 0.06 pounds of NO_X per MWh of generation, and modern combustion turbine peaker plants produce about 0.09 pounds of NO_X per MWh (Energy Commission 2004b). This suggests that wind power that displaces modern peaker plants would have approximately 1.5 times the environmental benefits (in terms of NO_X emission reductions) of wind power that displaces baseload natural gas plants. Wind power that displaces other types of generation, such as older peaker plants that have not yet been retrofitted with selective catalytic reduction systems, would have even greater NO_X reduction benefits.

Thus, because of this difference in emissions between baseload and peaker power plants, energy storage could help to improve the environmental benefits of wind power. These benefits are likely because time-shifting generation from off-peak to on-peak times through the use of energy storage also tends to improve wind power economics.

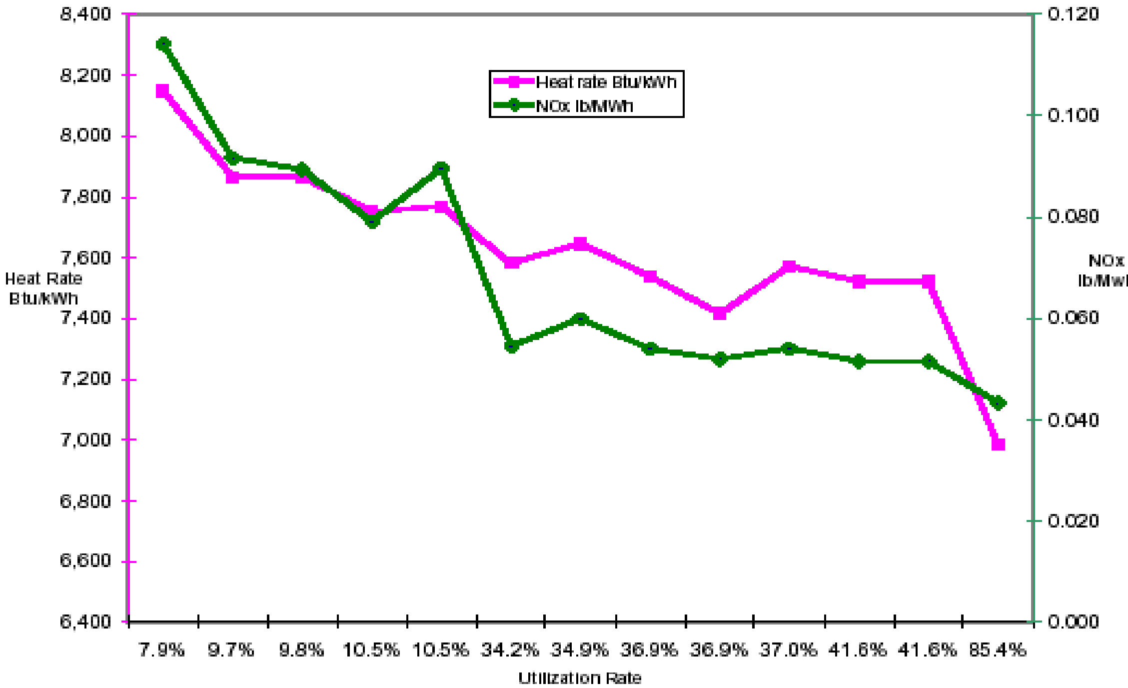


Source: Energy Commission 2004b

Figure 22. NO_X emissions from California power plants

Furthermore, at a more detailed level, wind power and energy storage can alter the dispatch profile of conventional power plants that are marginal at any given time. This also tends to impact emissions but in a more subtle way. Figure 23 shows that natural gas combined-cycle power plants are most efficient and least emitting when operated near peak capacity. At lower power plant utilization levels, efficiency ratings drop and emissions increase. As shown in the figure, efficiency levels expressed in terms of "heat rates," or Btus of fuel input for each kWh produced, vary by perhaps 15% from high to low levels of power plant utilization. Meanwhile, NO_X emissions can vary by up to threefold over this same range of variation in power plant utilization.

Energy storage can improve the environmental performance of wind power by allowing conventional combined-cycle power plants to operate most efficiently and with the lowest possible emissions during off-peak periods. The level of this benefit would depend importantly on the details of electricity generating plant dispatch patterns, but given the wide variation in NO_X emissions by power plant utilization, there is the potential for significant environmental impacts at this level.



Source: Energy Commission 2004b

Figure 23. Efficiency and NO_X emission curves by utilization rate for combined-cycle natural gas power plants

5.3. Making Hydrogen from Intermittent Renewables: Good for the Environment?

One interesting question with regard to making hydrogen for use as a vehicle fuel from intermittent renewable electricity sources is the extent to which this produces environmental benefits relative to alternative uses of the power and comparative means of hydrogen production. On one hand, making hydrogen from a non-polluting energy resource appears to be a clear winner from an environmental perspective. One produces hydrogen with no emissions ("green" hydrogen as some would call it) that can then be used in hydrogen-powered vehicles with low (hydrogen combustion engine) or no (hydrogen fuel cell) emissions from the vehicle itself. On the other hand, one must ask what the comparative benefits would be of using the renewables-produced electricity to displace other marginal sources of power generation, and to make hydrogen some other way.

In one analysis, wind energy would displace marginal electricity generation in California with an average greenhouse gas (GHG) emissions level of about 640 grams per kWh. Meanwhile, hydrogen produced through electrolysis from renewable sources and used in a fuel cell vehicle would displace about 470 grams per kWh of GHG emissions. Seen this way, from a GHG reduction perspective, electricity from renewables is better used to displace grid power than to produce hydrogen for vehicles (Thomas 2004).

However, the above analysis does not consider the fact that there are likely to be periods of time when intermittent renewables (and particularly wind) produce power at times when it is inconvenient for marginal generators to be displaced. This is the case because baseload power generators are marginal at off-peak times, and these baseload generators have both economic and environmental considerations that make it undesirable to "back off" on their generation in order to accommodate the production from intermittent renewables. Thus, during these off-peak times it may be desirable to use excess wind power to produce hydrogen for vehicles even if greater benefits could (theoretically) be gained by using that same power to displace other sources of power generation.

We generally concur that renewably generated electricity is generally best used to displace marginal fossil generators, typically natural gas peaker or mid-peaker plants or, in some cases, coal plants. With GHG emissions of 1,100 grams per kWh, coal power should be avoided when possible. With the much lower emissions of 500–550 grams per kWh for the natural gas combined-cycle turbines that are increasingly becoming the norm, however, the benefits of using renewables to displace electricity generation and using it to displace gasoline use in vehicles through the use of hydrogen fuel cell vehicles can be comparable.

6.0 Conclusions

We conclude that energy storage systems have the potential to improve the attractiveness of wind power in California both technically and economically, especially in the future with greater development of wind power resources. Energy storage coupled with power electronics can help to mitigate technical issues associated with wind and other intermittent generator integration with utility grids. More importantly, energy storage can mitigate the intermittent nature of wind power, its significant unpredictability, and its off-peak availability, making wind power better able to integrate with electricity markets and match typical electricity demand profiles in California.

However, we stress that the need for energy storage and/or backup power in conjunction with wind power developments is modest at low wind penetration levels and only becomes significant when wind power contributions exceed about 10% of total system energy (or about 20%–25% of system capacity). Furthermore, better wind forecasting/scheduling techniques and improved intermittent renewable energy integration strategies in general may reduce the importance of energy storage. However, if significant improvements in these areas prove difficult to achieve, we believe that energy storage is likely to play an important role in California's future electricity system.

6.1. Key Findings from Energy Storage Modeling and Assessment

The key findings from this analysis can be summarized as follows:

- Energy storage systems deployed in the context of greater wind power development were not particularly well utilized (based on the availability of "excess" off-peak electricity from wind power). This was especially true in the 2010 time frame (10% statewide wind penetration), with several hundred hours of operation simulated for the Southern California sites but very few hours of operation for the Northern California sites. The systems were better utilized (up to 1,600 hours of operation per year in some cases) with the greater wind penetration levels assumed for 2020 (20% total statewide wind penetration).

  The low energy storage system utilization levels modeled for 2010 were due partly to assumptions used in this analysis (e.g., that energy storage is used for bulk power storage from wind during time-averaged 15-minute periods of high availability and not to absorb energy over shorter time periods to address the wind availability forecasting error issue). More generally, the low energy storage utilization levels seen for 2010 resulted from the lack of significant *excess* wind power availability, particularly with the relatively low wind penetration levels assumed for the Northern California sites (~1% of statewide energy use).
- The levelized costs of electricity from these energy storage systems ranged from a low of \$0.41 per kWh—or near the marginal cost of generation during peak demand times—to many dollars per kWh (in cases where the storage is not well utilized). In order for these systems to be economically attractive, it may be necessary to optimize their output to coincide with peak demand periods, and to identify additional value streams from their use (e.g., transmission and distribution system optimization, provision of power quality and grid ancillary services, etc.).

- At low levels of wind penetration (1%–2%), the electrolyzer/fuel cell system was either inoperable or uneconomical (i.e., either no electricity was supplied by the energy storage system or the electricity provided carried a high cost per MWh).
- In the 2010 scenarios, the flow battery system delivered the lowest cost per energy stored and delivered.
- At higher levels of wind penetration, the electrolyzer/fuel cell system became more economical and at the highest levels of penetration in 2020 (18% from Southern California), the electrolyzer/fuel cell delivered the least costly energy storage.
- Projected decreases in capital costs and maintenance requirements along with a more durable fuel cell allowed the electrolyzer/fuel cell to gain a significant cost advantage over the battery systems in 2020.
- Sizing the electrolyzer/fuel cell system to match the flow battery system's relatively high instantaneous power output was found to increase the competitiveness of this system in low energy storage cases (2010 and Northern California in 2020), but in cases with higher levels of energy storage (Southern California in 2020), the electrolyzer/fuel cell system sized to match the flow battery output became less competitive.
- In our scenarios, the hydrogen production case was more economical than the electrolyzer/fuel cell case with the same amount of electricity consumed (i.e., hydrogen production delivered greater revenue from hydrogen sales than the electrolyzer/fuel cell avoids the cost of electricity, once the process efficiencies were considered).
- Furthermore, the hydrogen production system with higher-capacity power converter and electrolyzer (sized to match the flow battery converter) was more economical, due to economies of scale found to produce lower-cost hydrogen in all cases than the lower-capacity system that was sized to match the output of the solid-state battery.
- With regard to potential environmental impacts of the energy storage systems themselves, these systems are in general fairly benign from an environmental perspective, with the exception of emissions from the manufacture of certain energy storage system components (such as nickel, lead, cadmium, and vanadium for batteries) and particularly outside of the U.S. where battery plant emissions are less tightly controlled, and potential contamination from improper disposal of these and other materials is more likely.

We conclude that the overall value proposition for energy storage systems used in conjunction with intermittent renewable energy systems will depend on multiple factors:

- The interaction of generation and storage system characteristics and grid and energy resource conditions at a particular location
- The potential use of energy storage for multiple purposes in addition to improving the dependability of intermittent renewables (e.g., peak/off-peak power price arbitrage, helping to optimize the transmission and distribution infrastructure, and helping to mitigate power quality issues)
- The degree of future progress in improving forecasting techniques and reducing prediction errors for intermittent renewable energy systems

- Electricity market design and rules for compensating renewable energy systems for their output

6.2 Recommendations

Based on the outcome of this analysis, we recommend that the Energy Commission continue its strong support of renewable energy utility grid integration studies, analysis of energy storage systems, and analysis of the role of advanced technologies such as flow batteries and hydrogen production systems as additional elements of a clean energy future. Specific areas for additional research include the relative costs and benefits of different energy storage technologies, the potential for energy storage systems to mitigate wind power forecasting and scheduling errors (and the development of better wind forecasting techniques in general), the relative costs and environmental performance of backup power generation systems compared with energy storage systems, and additional studies of the California-specific grid impacts of relatively high (15%–20% of energy supplied) levels of wind power penetration.

In relation to our analysis of hydrogen production and re-use with electrolyzer/fuel cell devices as one type of storage system, we recommend additional research to understand the hydrogen storage aspects of these systems. Hydrogen storage in the wind turbine towers directly (as a "retrofit" storage concept) appears to offer attractive potential costs compared to conventional hydrogen storage at higher pressure. However, the safety of this concept has not been carefully investigated and this will be required for such systems to become practical. We therefore recommend additional research in this regard.

We further recommend that energy storage systems be considered in the context of current discussions for how wind power is to be compensated for participation in the state RPS program. Since utilities will apparently be allowed to consider dispatchability and reliability in a second round re-ordering of renewable energy contract bids, we suggest that attention be paid to how the additional dispatchability that is afforded by the integration of energy storage would be valued and compensated.

Finally, we note that this exploratory investigation has left many questions unanswered. We recommend additional studies to address these questions:

- What are the total potential benefits (economic and technical) to the California utility grid of integrating various types of energy storage with future wind power and other renewable energy systems in specific settings?
- In addition to the energy storage systems analyzed in this project, what other energy storage systems are of interest for energy management applications and how do their costs and benefits compare?
- To what extent would a finer resolution of analysis (shorter time intervals of analysis than hour-by-hour and more careful sizing of energy storage to wind capacity) reveal additional opportunities for energy storage from wind power, increase the potential utilization, and improve the economics of these systems?
- What are the broader implications for California electricity markets of the enhanced dispatchability and other potential benefits of integrating energy storage systems with intermittent renewables?

- How might the commercial success of plug-in hybrid or battery electric vehicles, or other significant changes in electricity demand profiles resulting from demand-response and pricing schemes, potentially level electrical loads on the grid and reduce the importance of the problem of excess off-peak power from wind energy systems?
- What are the potential impacts of hydrogen production for hydrogen-powered vehicle refueling on California's electricity system, including not only hydrogen compression/liquefaction energy but also potential electrolytic hydrogen production?

6.3 PIER Program Objectives and Potential Benefits for California

This project has helped to meet PIER program objectives and to benefit California in the following ways:

- **Providing environmentally sound electricity.** Energy storage systems have the potential to help make environmentally attractive renewable energy systems more competitive by improving their performance and mitigating some of the technical issues associated with renewable energy/utility grid integration. This project has identified the potential costs associated with the use of various energy storage technologies as a step toward understanding the overall value proposition for energy storage as a means to help enable further development of wind power (and potentially other intermittent renewable resources as well).
- **Providing reliable electricity.** The integration of energy storage with renewable energy resources can help to maintain grid stability and adequate reserve margins (relative to the alternative case in which no storage is added), thereby contributing to the overall reliability of the electricity grid. This study has identified the potential costs of integrating various types of energy storage with wind power, against which the value of greater reliability can be assessed along with other potential benefits.
- **Providing affordable electricity.** Upward pressure on natural gas prices, partly as a function of increased demand, has significantly contributed to higher electricity prices in California and other states. Diversification of electricity supplies with relatively low-cost sources, such as wind power, can help to provide a hedge against further natural gas price increases. Higher levels of penetration of these other (non-natural gas based) electricity sources, potentially enabled by the use of energy storage, can help to reduce the risks of future electricity price increases.

6.4 Final Conclusions

In conclusion, our expectation is that there will be only limited application of energy storage systems in conjunction with renewable energy development in California for at least the next several years. However, application of energy storage technologies may become more attractive in the future with higher levels of wind power use, depending on the outcome of efforts to better integrate intermittent renewable energy systems into utility grids and on the evolution of energy storage system cost and performance. We hope that this exploratory study has provided useful insights regarding the economics and other aspects of energy storage systems as they might be integrated with future wind power in California.

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8.0 Glossary of Abbreviations and Acronyms

AC = alternating current

AGC = automatic generation control

BESS = battery energy storage system

BPA = Bonneville Power Administration

Btus = British thermal units

CAES = compressed air energy storage

CAISO = California Independent System Operator

CETEEM = Clean Energy Technology Economics and Emissions Model

CPUC = California Public Utilities Commission

CWEC = California Wind Energy Collaborative

DC = direct current

DOE = U.S. Department of Energy

ELCC = electrical load carrying capacity

GIS = geographic information system

GHG = greenhouse gas

GJ = gigajoule or gigajoules

HOMER = Hybrid Optimization Model for Electric Renewables

HHV = higher heating value

H_2 = hydrogen

kg = kilogram or kilograms

kW = kilowatt or kilowatts

kWh = kilowatt hour or hours

LHV = lower heating value

LLNL = Lawrence Livermore National Laboratory

MPR = market price referent

MW = megawatt or megawatts

MWh = megawatt hour or hours

NOx = oxides of nitrogen

NREL = National Renewable Energy Laboratory

NPC = net present cost

PEM = proton exchange membrane

PG&E = Pacific Gas and Electric Company

PIER = Public Interest Energy Research Program

PHES = pumped hydro energy storage

psi = pounds per square inch

PV = photovoltaic

RPS = renewable portfolio standard

SCAQMD = South Coast Air Quality Management District

SMUD = Sacramento Municipal Utility District

SMES = superconducting magnetic energy storage

SO_2 = sulfur dioxide

UC = University of California

U.S. = United States

VRB = vanadium redox battery

WinDS-H2 = Wind Deployment Systems with Hydrogen

ZBB = zinc bromine battery