Public Interest Energy Research (PIER) Program

FINAL PROJECT REPORT

WIND STORAGE-ENHANCED TRANSMISSION RESEARCH AND DEVELOPMENT PROJECT

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ABSTRACT

Wind generation continues to be the fastest growing segment of the generation mix in the United States. Its proliferation presents system operating challenges due to its inherent power output variability. This study identifies specific California locations where wind generation intermittency is (or will become) a major problem and identifies the preferred type of electric energy storage plants to manage the impacts of wind power output intermittency. The study also used a metrics-based tool to determine the value of siting an energy storage plant at specified sites.

Three candidate sites, all located in Kern County, were identified for installation of electric energy storage plants to address wind power output variability issues. Two are substation sites for Southern California Edison, and one substation site is for Pacific Gas and Electric Company. The project team recommended installation of an energy storage plant near Pacific Gas and Electric Company's Midway Substation and Southern California Edison's substation sites at Cal Cement and Goldtown. For the power and energy capacity required at the selected sites, the only type of electric energy storage plant that is the lowest cost and uses commercially available equipment is the advanced compressed air energy storage plant.

The project team recommends use of an above-ground air storage system for the two Southern California Edison compressed air energy storage plants (a 70 megawatt (MW), 5-hour storage plant at the Cal Cement substation, and a 40 MW, 5-hour storage plant at the Goldtown substation); and an advanced compressed air energy storage plant using a below-ground air storage system (a 300-MW, 10-hour storage plant) to be sited near Pacific Gas and Electric Company's Midway substation).

The project team also prepared a technology transfer plan for the results of this project and a technology readiness plan of the metrics-based tool used in this project.

Keywords: Compressed air energy storage, CAES, DYNATRAN

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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 (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 six RD&D program areas:

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

What follows is the final report for PIR-07-010, conducted by the Electrical Power Research Institute. The report is entitled Wind-Storage-Enhanced Transmission Research and Development. This project contributes to the Renewable Energy program.

When the source of a table, figure or photo is not otherwise credited, it is the work of the author of the report.

For more information on the PIER Program, please visit the Commission's website at: http://www.energy.ca.gov/research/ or contact the Energy Commission at (916) 327-1551.

EXECUTIVE SUMMARY

While wind power generation continues to be the fastest growing segment of the power generation mix in the United States and worldwide, its proliferation to help meet Renewables Portfolio Standard presents many system operating challenges due to wind power plants' inherent variability to deliver power. This report documents the results of a study sponsored by the California Energy Commission to identify specific locations in California where wind generation power intermittency is (or will become) a major problem and to identify the best type of electric energy storage system to manage wind plant power intermittency at the identified electric utility electric grid locations.

Background

The integration of wind generation poses a number of challenges to the California electric grid. These include power fluctuations, transmission congestion, equipment overloads, reduced power quality, power production during nights when it is not needed, and significant ramping and regulation operational issues at the California Independent System Operator. Electric energy storage devices can address most of these issues if appropriate energy storage plants are chosen, specified properly, and sited at the proper locations. Commercial market readiness, cost, and land requirements for any specific energy storage technology must also be part of the decision process.

Objectives

The objectives of this study were to:

- Identify, via detailed technical feasibility assessments, at least two priority locations in California to deploy electric energy storage devices to address wind generator critical transmission and/or related operational issues.
- Define and quantify appropriate technology performance metrics associated with successfully integrating energy storage devices with grid locations affected by wind generators for each priority site.
- Develop equipment specifications to satisfy site requirements (type, size, capacity, reactive power capability, and so forth) for each selected priority site.
- Create a metrics-based tool that can 1) determine the value of siting an energy storage device anywhere in California and 2) determine its specific site location and characteristics (for example, storage type, megawatts [MW], megawatt hours [MWh], reactive power control) that would best address the site-specific challenges related to enhancing the integration of wind resources in California.

Approach

Project participants Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) contributed at least one year of transmission data for each site that the team investigated in this project. Additionally, each utility acquired more data and/or information on these transmission sites during the project. The transmission sites were chosen based on transmission

issues and/or energy storage opportunities at these sites. Additionally, the sites were selected to reflect the variety of wind generators in California. The project evaluation approach consisted of a two-step process implemented at the selected PG&E and SCE sites. The first step in the energy storage valuation and selection process used a preliminary metrics analysis tool and an energy storage economic assessment tool to perform a preliminary assessment of wind energy impacts at a given site. The second step in the process used a final, more detailed metrics analysis tool and a statewide (or sub-regionwide) grid operations software tool named DYNATRAN, developed and used successfully by Electric Power Research Institute for several years. This second step provided a final assessment and determined the value of deploying energy storage device(s) to address the California grid integration issues associated with wind generators at the specified sites identified. This second step also addressed other site specific issues/opportunities and determined the energy storage device type and design specifications most appropriate for the sites investigated.

Outcomes

The project team identified three candidate sites (two for SCE and one for PG&E) for installation of electric energy storage plants to address wind power issues. Due to the current and expected growth of wind generation issues in the Tehachapi wind resource area, the team recommended installation of an energy storage plant at the nearby PG&E Midway Substation. SCE's Antelope-Bailey Subsystem also suffers from issues associated with the power intermittency of wind generation. The sites in this SCE subsystem recommended for this study, Cal Cement and Goldtown, are primary grid interconnection points for wind generation in the SCE electric network system. To accommodate the capacity required at each of these sites, the only type of electric energy storage device/system that is the lowest cost and uses commercially available equipment is advanced compressed air energy storage. Compressed air energy storage systems "store" electricity by compressing and storing air until the energy is needed, at which time the air will be expanded through machinery to produce electricity. The project team recommended use of an above-ground air storage system for the two SCE plants (a 70-MW, 5-hour storage plant at the Cal Cement substation, and a 40-MW, 5-hour storage plant at the Goldtown substation) and an advanced compressed air energy storage plant (a 300-MW, 10-hour storage plant) using a below-ground air storage system installed near PG&E's Midway Substation. By working with PG&E, staff familiar with its natural gas storage facilities and potential underground air storage media, the team determined that there are potential sites for a below-ground compressed air energy storage plant that can connect into the Midway Substation. The project team recommended that PG&E and SCE proceed to more detailed study of these sites and specification of detailed engineering designs of these plants. The team also prepared a technology transfer plan for the results of the study, and a technology readiness plan for metrics-based tool used during this project.

Benefits to California

This project promotes the deployment of electric energy storage technologies to address challenges incurred on the California grid and transmission systems due to the presence of wind generation in California. The project will help California meet its renewable energy policy goals by giving California utilities and grid operators a tool whereby intermittency and operational issues of wind generators can be properly managed, as are non-intermittent generation resources in California and other U.S. locations.

This project meets the California Energy Commission's Public Interest Energy Research Program goal of "improving the reliability/quantity of California's electricity," the goal to "reduce the cost of electricity and increase value," and the goal to "seek viable options for electricity problems through demonstration of electric energy storage as a technically sound, cost-effective and broadly applicable solution for reliable electricity system capacity and for electric energy management in California." The metrics-based tool developed and validated in this study will enable the Energy Commission and other groups within California and in other states to complete location-by-location assessments of the value of deploying energy storage plants to mitigate wind generator issues today, and in the future. Deployment of energy storage plants will help California reduce its dependence on fossil fuels by facilitating utilities' ability to integrate and manage larger proportions of intermittent and variable renewables without degrading the performance of the electric grid.

Related reports that may be useful to the reader of this report include Electric Power Research Institute numbered reports 1021379, 1017905, and 1016011. They can be downloaded at www.epri.com.

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CHAPTER 1: Introduction

Project Background

The integration of wind generators poses a number of challenges to the California electric grid, including power fluctuations, transmission congestion, equipment overloads, reduced power quality (for example., high transient harmonics and voltage-ampere reactives or VARs), power production during night time periods when it is not needed, and significant ramping and regulation grid operational issues at the California Independent System Operator (California ISO). Energy storage plants are capable of addressing most, if not all, of these issues, if the proper ones are chosen, properly specified, and sited at proper locations. Commercial market readiness, cost, and land requirements for any specific energy storage plant must also be part of the decision process to construct energy storage plants.

The Electric Power Research Institute (EPRI) performed the original research contained in this report under funding provided by the California Energy Commission's (Energy Commission) Public Interest Energy Research (PIER) Program.

Project Goal

The goal of this project is to facilitate the deployment of energy storage plants to address challenges incurred on the California grid and transmission systems due to the presence of wind generators. A two step metrics-based process is used to quantify improvements that can be achieved through energy storage plant deployment, and suitable energy storage plants will be proposed for at least two sites in California. The project will help California meet its renewable energy policy goals by giving grid operators a tool whereby power output intermittency and grid operational issues can be managed much like those for non-intermittent generation resources.

Project Objectives

The objectives of this project are to:

- Identify via detailed technical feasibility assessments, at least two priority substation locations in California to deploy energy storage plants to mitigate wind generator transmission and/or grid operational issues.
- Define and quantify appropriate technology performance metrics associated with successfully integrating energy storage plants at California electric grid locations impacted by wind generators for each priority site identified.
- Develop equipment specifications to satisfy California site requirements (plant type, size, capacity, VAR capability, and so forth) for each priority site identified.
- Use a metrics-based tool to determine the value of siting an energy storage plant anywhere in California and determine the energy storage plants' characteristics (for

example, storage type, MW, MWh, VAR control) that would best address the site specific challenges related to enhancing the integration of wind resources in California.

Relationship to California Energy Commission Goals

This project meets the Energy Commission goal of "Improving the Reliability/Quantity of California's Electricity" by advancing the use and applications of a portfolio of energy storage plants to meet specific California needs.

This project meets the Energy Commission goal to "Seek viable options for electricity problems through demonstration of electric energy storage plants as a technically sound, cost-effective and broadly applicable solution for reliable electricity system capacity and for electric energy management in California."

This project also meets the Energy Commission goal to "reduce the cost of electricity and increase value" by enabling new energy storage options to be evaluated for potential use in California that will allow less expensive night-time electric energy to be effectively stored and used to replace relatively more expensive energy during the day-time. Based on the above, the project significantly advances the application and understanding of the value of electric energy storage systems in the California to develop information to enable California electric utilities to better plan, deploy, use, and monetize the value from these types of assets.

Organization of This Report

The remainder of this section of the report lists the project tasks and describes the technical approach used in the study. Chapter 2 describes the analysis and results for the Pacific Gas and Electric Company (PG&E) operating area. Chapter 3 covers the analysis and results for the Southern California Edison (SCE) operating area. Chapter 4 presents the study conclusions and recommendations. Chapter 5 presents a list of acronyms and a short glossary. Appendix A presents the project's Technology Transfer Plan, and Appendix B presents the project's Technology Readiness Plan. EPRI submitted separate PG&E and SCE Detailed Site Selection Reports and Detailed Storage Device Reports to the California Energy Commission.

Technical Tasks

Transmission Sites Selected

A. **Goals:** The goal of this task is to identify at least two California transmission substation sites where energy storage devices can be deployed to mitigate wind generator issues.

B. **Task:** EPRI identified at least two California transmission sites where energy storage devices could mitigate wind generator issues in a region encompassing the PG&E and SCE electric grid regions.

C. **Product:** The identification of at least two transmission sites in California where energy storage plants should be sited to mitigate wind generator issues.

Energy Storage Devices Selected

- **A. Goals:** The goal of this task is to identify at least one energy storage plant for each of the transmission substation sites selected in Task 2 above, which will mitigate wind generator issues.
- **B. Task:** EPRI identified at least one energy storage device for each of the sites selected in the task above, to mitigate wind generator issues.
- **C. Product:** The identification of at least two transmission substation sites in California, and the identification of an energy storage plant at each substation site, which will mitigate wind generator issues.

Metrics Tool Developed and Tested

- **A. Goals:** The goal of this task is to use the results and lessons learned from the above tasks and use a metrics tool to evaluate energy storage plants at proper transmission sites to mitigating wind generator issues in California.
- **B. Task:** EPRI developed and employed a metrics tool to identify energy storage devices that are cost-effective when sited at selected transmission substation sites to mitigate wind generator issues.
- **C. Product:** Application of a metrics-based tool to identify energy storage device(s) that are cost-effective when sited at proper transmission sites to mitigate wind generator issues.

Technology Transfer Activities

- **A. Goal:** The goal of this task is to develop a plan to make the knowledge gained, results, and lessons learned during this project available to key decision makers in California.
- **B. Task:** EPRI prepared a Technology Transfer Plan.
- **C. Product:** Final Technology Transfer Plan.

Technical Approach

Transmission Site Selection

PG&E and SCE provided at least one year of data for each transmission site the project team selected for this study. Also, each utility acquired additional data and/or information on these transmission sites during the project. Selection of the transmission substation sites was based on transmission issues and/or energy storage plant opportunities at these sites. Additionally, the selection process considered the variety and power output characteristics of wind generators (existing and proposed new wind generators) that exist in California, which need to be properly addressed during the project. For example, some older wind generators cause special harmonic and VAR problems that some types of new wind generators do not cause. However, to ensure project success, transmission substation sites associated with both old and new wind generators were included in the transmission substation sites investigated.

For each substation site investigated, the data provided by the participating utilities included the following:

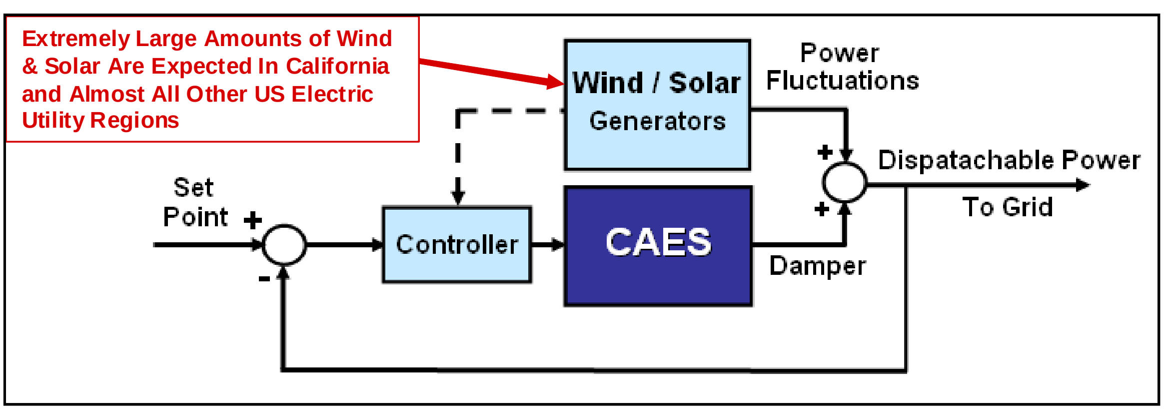
- Outage/reliability data (such as, CAIDI, CAIFI, SAIDI, and SAIFI data).
- Power throughput at transmission sites (such as, MW and MVAR data).
- Voltage levels and power demand trends.
- Short circuit current capability of substation equipment at transmission sites.
- Data for analyzing the remaining useful life of equipment, including age.
- One minute data (for specific time periods).
- Power quality data (such as, harmonics for specific time periods at some substations).
- Surface area available for deploying an energy storage plant at the investigated sites.

The above items served as a portion of the metrics analyses performed to determine the type and size of an energy storage plant that can be deployed to address wind generator issues at the investigated substation sites. The project team also used PG&E and SCE one-line electrical diagrams for appropriate substation equipment and/or the appropriate transmission lines coming into and out of the selected transmission substation sites.

Energy Storage Device Selection

Figure 1-1 illustrates how an energy storage plant can act as an electric "shock absorber." Wind and other renewable energy resources produce power output oscillations and/or provide power when not needed, which limits their value. The solution is to deploy an electric energy storage shock absorber plant, which is sized and controlled to reduce load leveling, ramping, frequency oscillation, and/or VAR problems.

Figure1-1: CAES and/or Other Storage Plants Can Act as an Electric "Shock Absorber" to Dampen Fluctuating Wind and/or Solar Power Plant Output



Source: EPRI

There are a wide variety of energy storage plants available today. However, only a subset of these energy storage plants are appropriate and commercially ready to mitigate the power fluctuations, VAR, power quality, or voltage stability issues associated with wind generators. EPRI, PG&E, and SCE are leaders in the development, evaluation, and testing of energy storage plants for a wide variety of electric utility applications. Some of this work was supported by the California Energy Commission, EPRI, and the U.S. Department of Energy (DOE), as well as the vendors who are attempting to develop and commercialize one or more types of their own energy storage plants. The capabilities of various energy storage technologies are summarized in Table 1-1 and Figures 1-2 and 1-3.

Table1-1: Key Capability Metrics for Electric Energy Storage Technologies

Storage Technology	Pumped Hydro	Compressed Air (CAES)		Battery[1]	Flywheel	SMES[2]	Super Capacitors
		Underground	Above Ground				
	← Larger Scale (Grid) - Smaller Scale (Distributed) →						
Capacity	< 24,000 MWh	400 – 7,200 MWh	20 – 80 MWh	< 200 MWh	< 100 kWh	0.6 kWh	0.3 kWh
Discharge Time @ Max. Output	~ 12 hrs	4 – 24 hrs	2 – 4 hrs	1 – 7 hrs	< 1 hr	10 sec	10 sec
Power Level	< 2000 MW	100 – 300 MW	10 – 20 MW	< 30 MW	< 100 kW (each)	200 kW	100 kW
Response Time	30 ms	3 – 15 min	3 – 15 min	30 ms	5 ms	5 ms	5 ms
AC-AC Efficiency	0.87	0.85	0.85	0.70 – 0.85	0.93	0.95	0.95
Lifetime	40 years	30 years	30 years	2-10 years	20 years	40 years	40 years
Total Capital Cost[3]	2,100 $/kW	600 – 750 $/kW	1,300 – 1,550 $/kW	350 – 1,250 $/kW	3,700 – 4,300 $/kW	380 – 490 $/kW	300 – 450 $/kW

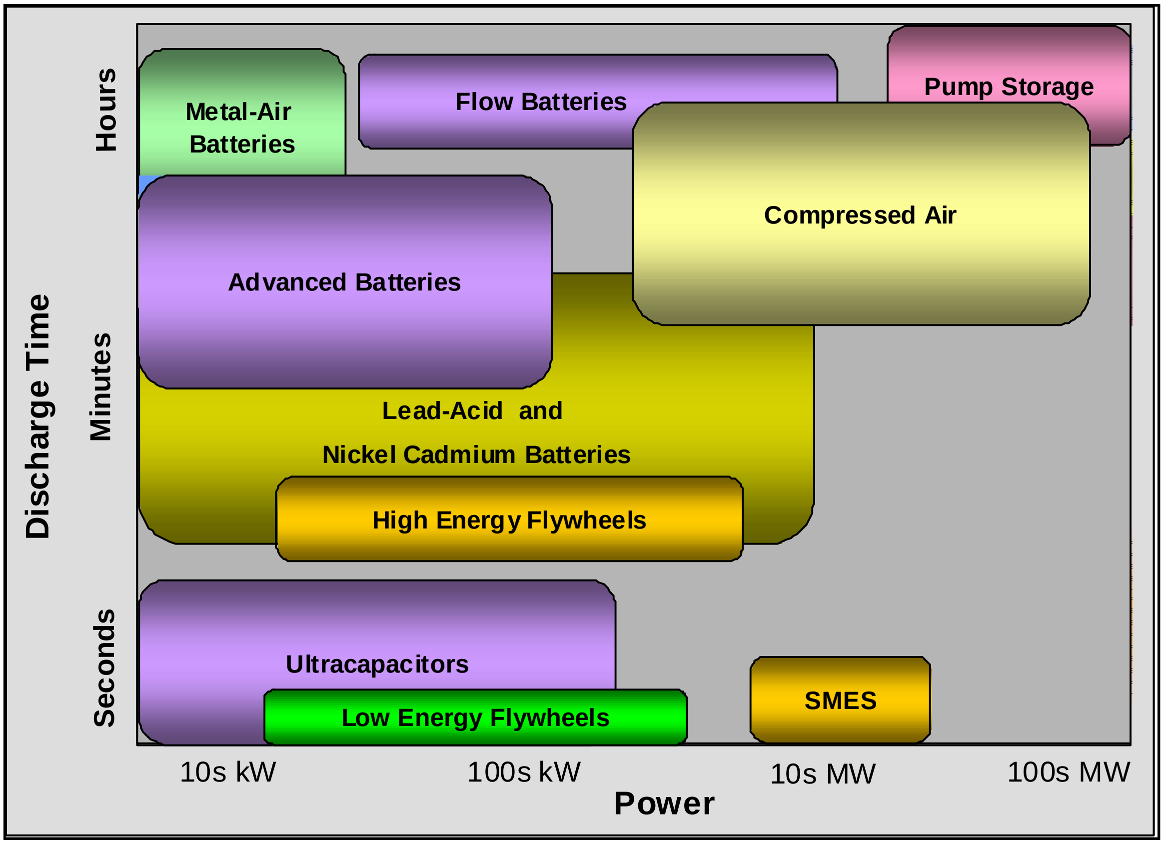
Source: EPRI

[1] Includes lead acid, sodium sulfur, flow, small cell lithium-ion and advanced large cell lithium-ion batteries.

[2] Superconducting Magnetic Energy Storage.

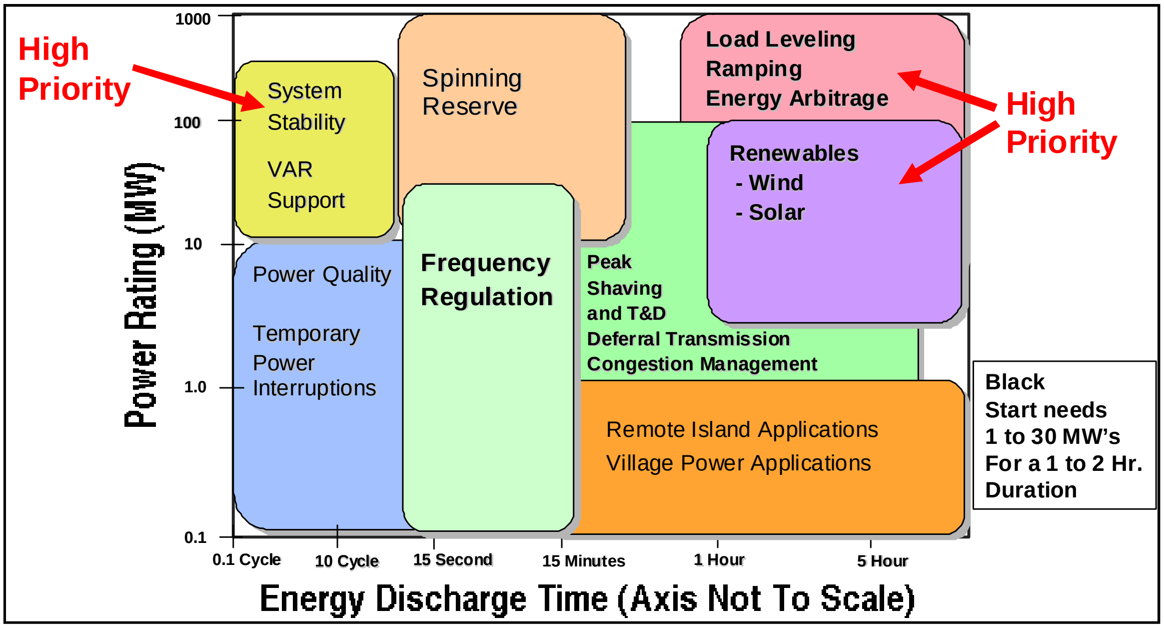
[3] Total Capital Cost = $/kW + (Number of Hours Discharge x $/kWh).

Figure1-2: Capability Metric for Discharge Time Versus Power Rating of Energy Storage Technologies



Source: EPRI

Figure1-3: Capability Metric for Power Rating Versus Energy Discharge Time of Energy Storage Technologies



Source: EPRI

Estimated capital costs for storage technologies are presented in Table 1-2. The total capital cost is the sum of two components: a fixed portion, and a variable portion. The fixed portion (in $/kW in Table 1-2) is independent of the number of hours of storage that the energy storage plant provides. The variable portion (in $/kW-Hours multiplied by H, hours, in Table 1-2) is dependent on the number of hours of storage that the energy storage plant provides. The number of hours shown are simple examples that are relevant to each particular type of energy storage plant delineated in Table 1-2.

Metric-Based Evaluation Process

Only a subset of the energy storage plants delineated in Table 1-2 is appropriate to mitigate California wind issues (such as, California ISO ramping, regulation and load leveling issues) and/or local transmission issues in California (such as, power fluctuations, VAR, power quality, or voltage instability issues). The approach taken in this project consists of a two-step process that uses a metric-based approach to evaluate the value of deploying an energy storage plant at any specified location in the California grid and determines the type of energy storage plant most appropriate to address the particular wind issues/opportunities at any specific identified California grid substation site. This two-step process and associated tool was developed utilizing the identified PG&E and SCE substations sites. This metrics-based tool, developed through the above process, will enable the California Energy Commission or other groups within California to complete statewide, location-by-location assessments of the value of deploying one or more energy storage plants to mitigate California wind generator issues today, and in the future.

Table1-2: Energy Storage Plants: Capital Cost Comparisons

Technology	$/kW +	$/kW-H* x	H =	Total Capital, $/kW
Compressed Air				
- Large, salt (100-300 MW)	640-730	1-2	10	650 to 750
- Small (10-20MW) AbvGr Str	800-900	200-240	2	1200 to 1380
- Small (10-20MW) AbvGr Str	800-900	200-240	4	1600 to 1860
Pumped Hydro				
- Conventional (1000MW)	1500-2000	100-200	10	2500 to 4000
Battery (10 MW)				
- Lead Acid, commercial	420-660	330-480	4	1740 to 2580
- Advanced (target)	450-550	350-400	4	1850 to 2150
- Flow (target)	425-1300	280-450	4	1545 to 3100
Flywheel (target) (100MW)	3360-3920	1340-1570	0.25	3695 to 4315
Superconducting (1 MW) Magnetic Storage	200-250	650,000 - 860,000	1/3600	380 to 490
Super-Capacitors (target)	250-350	20,000 - 30,000	1/360	310 to 435

* This capital cost is for the storage "reservoir", expressed in $/kW for each hour of storage. For battery plants, costs do not include expected cell replacements. The cost data are in 2009 $'s and are updated by EPRI periodically. Costs do not include permits, all contingencies, interest during construction and the substation.

Source: EPRI

The first step in the energy storage valuation and selection process is to use a preliminary metrics analysis (described below) and an energy storage economic assessment tool (developed and used successfully by EPRI in the past) to determine a preliminary assessment of a given energy storage plant type at a specified California substation site. The second step in the process utilizes a final, more detailed metrics analysis tool (described below) and a grid operations software tool developed and used successfully by EPRI for several years (for example., the EPRI DYNATRAN software tool), which is also described below. The second step in the process provides a final assessment and determines the value of deploying one of more energy storage plants to mitigate the integration issues associated with wind generators at the specified substation sites. This second step also addresses other site specific issues/opportunities and determines the energy storage plant type and design specifications most appropriate for the substation sites investigated.

Step One

Step one in the process consists of a preliminary metrics analysis and a preliminary energy storage economic screening analysis. These elements of step one are based on a set of technical and economic screenings that determine, in a preliminary manner, how well each appropriate energy storage technology can mitigate the wind issues at each of the transmission substation sites being considered. This preliminary technical screening process uses the metric criteria and capabilities shown in Table 1-1 and Figures 1-1 and 1-2; and the preliminary economic screening process uses the data shown in Figure 1-3.

Step Two

The second step in the selection process starts with the set of energy storage technologies that emerged from the step one process. Then, in step two, a detailed metrics analysis is performed using utility analyses and transmission site data for such items as voltage fluctuation, transient stability, dynamic stability, transmission line protection, congestion, VAR support, and grid reliability indices. Then, a techno-economic analysis is performed using EPRI's DYNATRAN software tool, which simulates the local or statewide grid economic costs and values for running the grid with and without the energy storage plant options being considered. The value for each storage plant option is expressed by a levelized annual cost, which is determined by subtracting the levelized annual costs *with* the energy storage plant at the transmission substation site from the annual levelized costs when the energy storage plant is <u>not</u> at the transmission substation site. DYNATRAN performs a simplified version of the California ISO unit commitment and unit commitment exercise, which accounts for transmission bottlenecks (with real and reactive power flows) and accounts for the dynamic performance of the wind and non-wind generators in the region (or state) with and without the energy storage plant(s) under consideration. The result of the DYNATRAN analysis is the quantified value of the energy storage plant that has the most value in terms of a levelized annual cost basis (in present value annualized dollars/year), which mitigates the wind generation issues/opportunities identified at the substation sites being considered.

Inputs to DYNATRAN Simulations

Following are the input data and assumptions used in the DYNATRAN simulations.

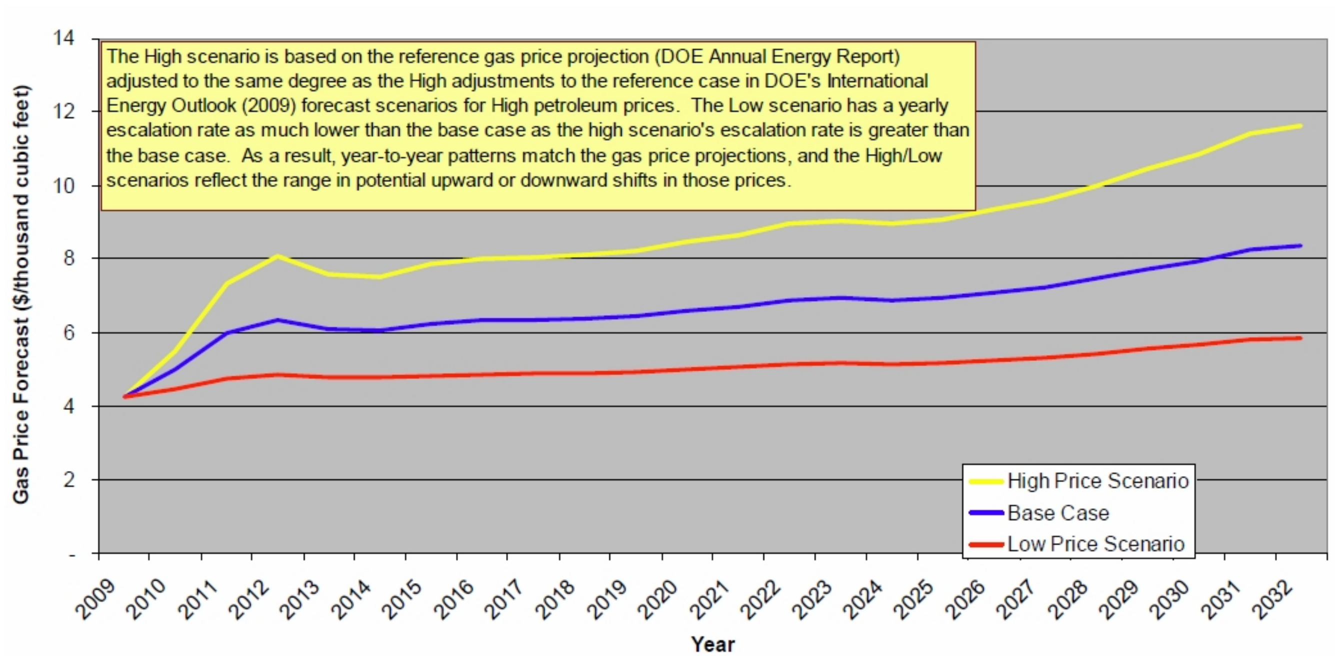
Part 1: Natural Gas Prices

Three fuel price forecasts were developed, as follows (Figure 1-4). A seasonal pattern of monthly prices compared with annual average prices was developed from DOE/EIA's monthly data for natural gas prices delivered to electricity providers in California over the past eight years. Two years of extreme price variation were excluded to establish a typical-year pattern. DOE/EIA's most recent Annual Energy Outlook provided a base-case long-term price forecast for natural gas prices, delivered to electricity producers. The typical-year monthly price pattern was applied to the annual price forecasts to obtain monthly gas prices for each of the years from 2012 to 2032, the economic planning horizon PG&E and SCE currently use to justify building a new generation or energy storage plant. DOE/EIA's Annual Energy Outlook provided high and reference forecasts for natural gas and petroleum prices on the international market.

A high forecast for California was developed by adjusting the year-to-year escalation rates for the base case by the same proportion as the high DOE oil-price forecast presents a change from the reference case. The average high-case escalation rate for natural gas from 2012 to 2032 is 2.3 percent. For example, between 2012 and 2015, the reference oil prices escalate on average 10 percent per year, while in the high case, average near-term escalation rates are 17 percent per year. Between 2014 and 2015, forecasted natural gas price grows by 3 percent in the base case. For the high-price case for natural gas, an escalation rate of (17/10) times 3 percent, or 5.1 percent was applied.

A low forecast for natural gas in California was developed by creating a mirror image of the high-forecast yearly growth trajectory. In each year, the difference in escalation rates between the high and low cases was calculated. For the low case, the escalation was set at the same amount less than the base case, as the high-case escalation rate was greater than the base case. The average low-case escalation rate for natural gas from 2012 to 2032 is 1.0 percent. For example, in 2015, DOE's base-case forecast has a 3 percent escalation rate and DOE's high-case forecast has a 5.1 percent escalation rate, differing by 2.1 percent. For the low case, the escalation rate for 2015 was set at 3 percent, minus 2.1 percent; namely, 0.9 percent.

Figure1-4: Long-Term Fuel Price Cases for the Three Scenarios



Source: EPRI

Part 2: Hourly Loads and Prices

Hourly system load shapes were developed from California ISO archived data for SCE and PG&E service territories. Beginning with the complete hourly profile for 2008, profiles for 2012-2032 escalated the 2008 load profile at 2 percent per year. The escalated shapes match weekly (Monday through Sunday) profiles from year to year.

Hourly energy prices were developed as follows. From the California ISO, aggregate hourly market clearing prices were available for April 2009 through March 2010. This yields one complete 8,784-hour starting-year price profile. (Note: 2010 is a "leap year." Thus, there are 8,784 hours in this year.) A base-case forecast was developed by applying the escalation rates from the natural gas forecast to the energy prices in hours 7 a.m. until 11 p.m. For the off-peak hours (set at 11p.m. until 7 a.m.), escalation was set at the lesser of the gas price escalation rate and the escalation rate for coal in DOE/EIA's reference case (for example, minus 0.27 percent).

A marginal-cost forecast for the high-gas-price case was developed based on the yearly escalation rates for natural gas in the high fuel price forecast. Again, in the off-peak hours, escalation is limited. For the high-price case, off-peak escalation was set at the lesser of the gas price escalation rate and the escalation rate for coal in DOE/EIA's high case (for example, 3.3 percent).

A marginal-cost forecast for the low-gas-price case was developed based on the yearly escalation rates for natural gas in the low fuel price forecast. Note that this approach yields a mirror-image, low-price forecast trajectory when compared with the high case. Again, in the off-peak hours, escalation was set at the lesser of the gas price escalation rate and the escalation rate for coal in DOE/EIA's low coal-price scenario (for example, minus 0.59 percent).

CHAPTER 2: EPRI-PG&E Wind, Transmission, and Energy Storage Analysis

Introduction

PG&E has been a leader in renewable and low greenhouse gas emitting energy resources for many years. Some of the first commercial wind farms in the world were built in PG&E's service area in the 1980s. PG&E has long recognized the flexibility provided by large, grid-scale bulk energy storage systems. The Helms pumped storage facility was built in 1984 and supplies 1200 MW or about 7 percent of peak resource needs in California. Wind and solar resources are the primary resources that California will employ to meet its mandated 33 percent renewable energy portfolio by 2020 (Table 2-1). Installing energy storage plants near variable output renewable resources, such as wind and solar, has been identified by the California Independent System Operator, California Energy Commission, and others as a key technology that will enable integration of large amounts of wind energy into California's electric grid.

Table 2-1: Forecast for 33 Percent Renewable Resources in California[4]

Resource	Existing MW (2006)	Forecast Additions MW (2020)	Total MW (2020)
Biomass	845	980	1,825
Geothermal	1,977	2,385	4,362
Wind	2,706	10,142	12,848
Residential Rooftop Solar	Unknown	3,000	3,000
Concentrated Solar Thermal	465	2,650	3,115
Total	5,993	19,157	25,150

Source: California Energy Commission

The PG&E service area contains 18,610 miles of interconnected transmission lines that serve over 1000 substations with voltages ranging from 60 kV to 500 kV. Major wind sites interconnected to PG&E's transmission system are located at Altamont, near the San Francisco Bay Area and Tehachapi, located southeast of Bakersfield. Other smaller wind sites are

[4] To put this in perspective, the CPUC reported that California's investor owned utilities collectively served 15.4 percent of their 2009 electric load with renewable energy, up from 13 percent in 2008.

dispersed around PG&E’s service territory. One of the goals of this report is to implement tools that can be used to assess the economic value of energy storage and assist in determining the optimum location to site energy storage plants. This will help mitigate possible negative impacts caused by integrating increasing amounts of wind energy into PG&E’s transmission system.

Candidate Energy Storage Sites

PG&E considered the following factors when choosing the candidate sites:

- Proximity to an existing major wind site.
- Planned future expansion of the major wind site.
- Possible reliability, operability, power quality, or other issues created by proximity to the wind site.
- Size of the electrical demand served by the proposed substation site.
- Available land at the candidate site.
- Suitability of the proposed site for large-scale storage technologies like pumped hydro or compressed air energy storage plants using underground air stores (for example, pumped hydro needs to be near a suitable reservoir with sufficient hydraulic head).

PG&E initially selected Midway and Tesla substations as possible locations for an energy storage plants. These substations are located near large wind sites: Tehachapi and Altamont, respectively. Currently, these substations do not have any voltage, power quality, or reactive power issues caused by nearby wind generators. The reason this occurs is that these substations are connected to the 230-kV and 500-kV bulk, high voltage California electrical network, which currently has ample capacity and electrical “stiffness.” However, both of these substations have a key issue in that time shifting via bulk energy storage plants is dramatically needed to shift off-peak wind generation to on-peak demand time periods (when energy is most needed by the California ISO to control the California electric grid network) and absorbed during off-peak demand time periods when energy is required by the California ISO to be stored and later used in California. Thus, this energy storage process is needed to smooth out the wind power time profile to best meet California customer demand profiles and electric grid network needs.

Midway substation is located in the southern San Joaquin valley west of Bakersfield and southwest of Fresno (see Figure 2-1). The Midway substation is a major bulk transmission substation located along the California Oregon Intertie (Path 15) with major transmission ties to the both Northern and Southern California and beyond. Midway substation is interconnected to the Tehachapi wind site through the Midway-Vincent No. 3, 500-kV line. Tehachapi currently has a maximum wind production capacity of approximately 700 MW with firm plans to increase output to over 4000 MW in the next 5 years. Depending on the time of day and season, up to several thousand megawatts of Tehachapi wind generation will flow through the Midway substation. The primary purpose of an energy storage plant at or near the Midway substation is to use it to shift off-peak wind generation to serve peak electric demand in California.

Figure 2-1: Location of PG&E Midway Substation

Source: EPRI

The Midway substation is located near areas of petroleum and natural gas wells. Surveys by PG&E and the State of California indicate that nearby abandoned gas or oil wells may make suitable sites for underground storage of compressed air, making large-scale compressed air energy storage (CAES) viable for this site.

Tesla Substation, along with Metcalf and Vaca-Dixon 500-kV Substations, is one of the three major transmission substations that serve the San Francisco Bay area. Located on the southeastern edge of the San Francisco Bay area, near the city of Livermore, the Tesla Substation is along the California Oregon Intertie (Path 13) with major transmission ties to both Northern and Southern California. It is also located adjacent to the Altamont wind resource area. Altamont has a peak wind production capacity of approximately 500 MW with no current plans to increase its power output. The primary purpose of an energy storage site at Tesla Substation would be to shift off-peak wind generation to serve peak electric demand in California. Because of its proximity to a major load center, there are opportunities to use an energy storage plant to provide ancillary services that could enhance the reliability of the transmission supply of the Greater San Francisco Bay Area.

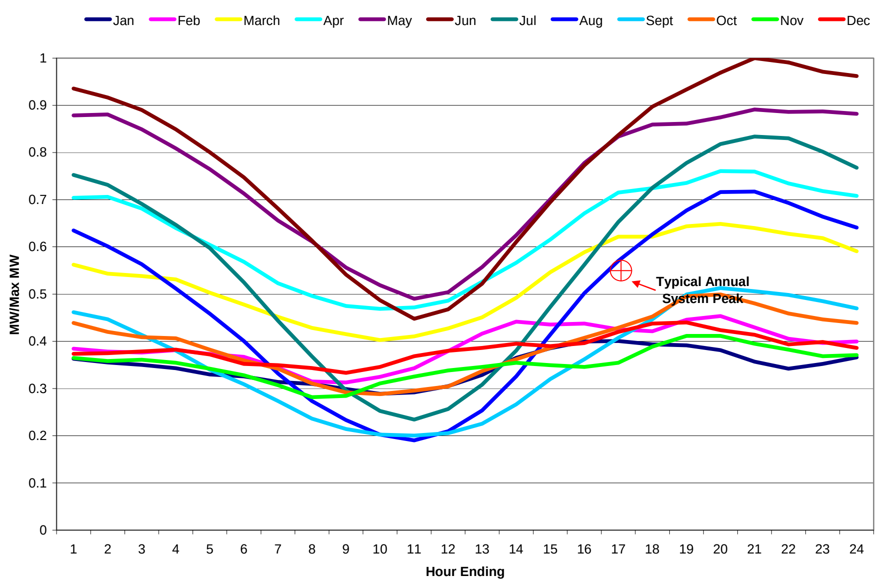
Table 2-2 lists these two PG&E transmission sites (Midway and Tesla), which are most likely to benefit from the addition of one or more energy storage plants. Figure 2-2 shows the daily wind power production by month at Tehachapi. The wind production from Tehachapi varies seasonally, with the highest wind output occurring in late spring and early summer. Minimum power production occurs in fall and in winter months. Daily power production is lowest at 1100 hours (for example, 11 AM) and highest around 2100 hours (for example, 9 PM). Typical peak demand occurs at approximately 1700 hours (for example, 5 PM) in July or August.

Table 2-2: List of PG&E Transmission Sites Likely to Benefit From Energy Storage

Site	Lines	Voltages	Load/Power Flow Characteristics	Available Land	Nearby Wind Farms (Capacity)	Issues Created by Wind Generation
Midway	Located on California Oregon Intertie. Major transmission ties to Fresno, Bakersfield, and Southern California	500 kV, 230 kV, & 115 kV	Networked Bulk Transmission	Yes, may require expansion of existing fence	Tehachapi (750 MW, expanding to 4200 MW by 2012)	Generation/Load Leveling, Ramping
Tesla	Located on California Oregon Intertie. Major transmission ties to SF Bay Area.	500 kV, 230 kV, & 115 kV	Networked Bulk Transmission	Yes, may require expansion of existing fence	Altamont (500 MW)	Generation/Load Leveling, Ramping,

Source: EPRI

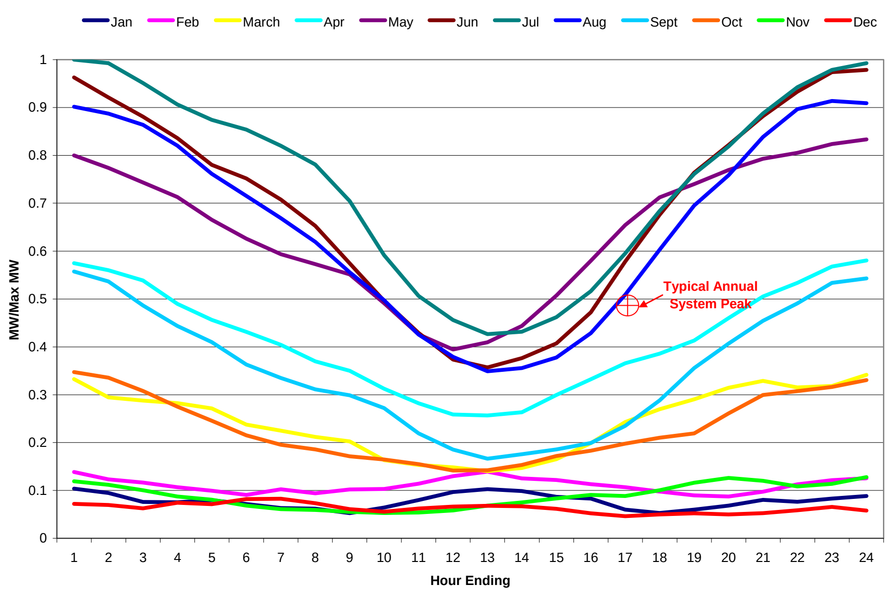
Figure 2-2: Average Tehachapi Monthly Wind Plant Power Production as a Ratio of MW Output to Max MW Output



Source: PG&E

Figure 2-3 shows the daily wind production by month at Altamont. The wind production from Altamont varies seasonally, with the highest wind output occurring in late spring through early fall. Production rapidly drops off in late fall and winter. Daily production is lowest at 1200 hours (12 noon) and highest around 2400 hours (12 midnight). Typical peak demand occurs at approximately 1700 hours (5 PM) in July or August.

Figure 2-3**: Average Altamont Monthly Wind Plant Power Production as a Ratio of MW Output to Max MW Output**



Source: EPRI

Final Set of Sites Selected

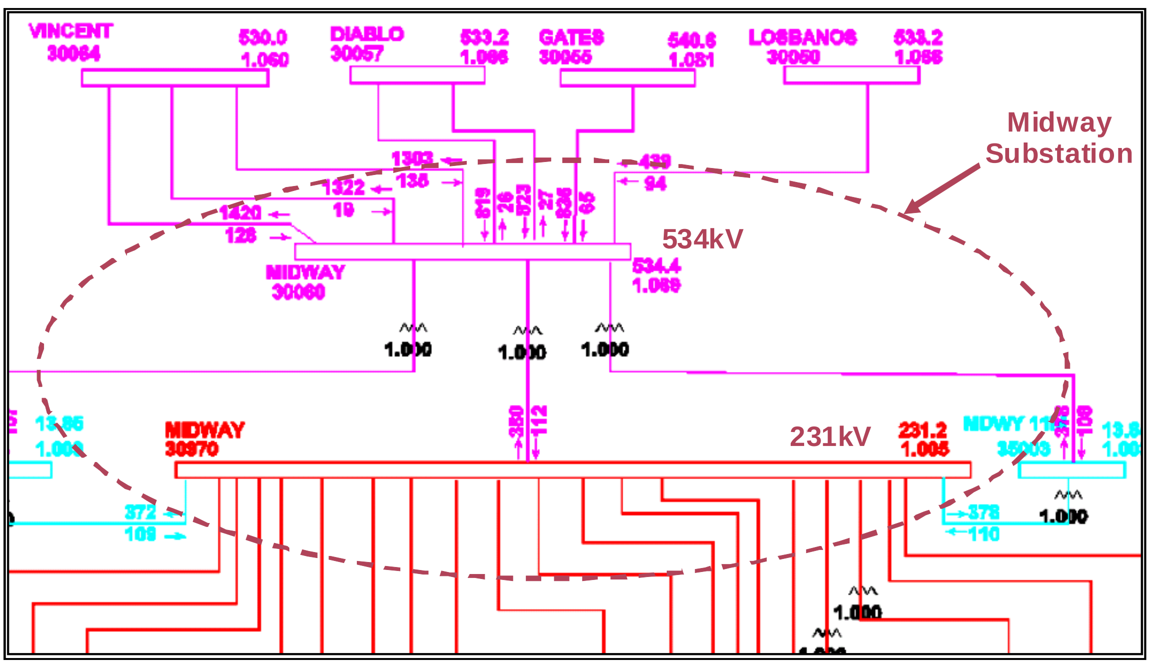
Midway substation was chosen as the candidate site for incorporating a bulk energy storage plant on the PG&E transmission system because of its proximity to wind generation at Tehachapi and because its location possesses the unique geology that makes large, bulk-scale CAES using an underground air store possible. Tehachapi currently has over 750 MW of interconnected wind generation with firm plans to increase wind generation there to 4200 MW's over the next 5 years. The increase in Tehachapi's output places it as the premier wind energy location in California. In comparison, the Altamont wind generation site, near the Tesla Substation, generates about 500 MW, with no current plans for expansion. Figure 2-4 shows the estimated power flow for the summer peak in year 2014 at the Midway substation.

PG&E and EPRI chose Midway substation as the best location for incorporating a bulk energy storage plant on PG&E's transmission system for the following reasons:

- There are currently plans to expand Tehachapi's nameplate wind generation capacity to 4200 MW's over the next several years. Once this expansion is complete, the Tehachapi wind site will be the largest source of wind energy in California. SCE and PG&E have signed contracts to purchase the renewable energy from these wind turbines to meet the California mandated renewable energy portfolio goal of 33 percent of energy from renewable sources by 2020. Depending on the time of day, up to several thousand megawatts of this wind power will be flowing through the Midway substation.

- Midway is an ideal site for a storage plant that would store wind energy when energy demand is low and deliver it to California energy consumers during peak demand periods.
- Midway substation is located near areas of petroleum and natural gas wells. Surveys by PG&E and the State of California indicate that nearby abandoned gas or oil wells may make suitable sites for CAES that use underground air stores, making one or more large-scale CAES plants viable for this site.

Figure 2-4: Estimated Power Flow for Summer Peak, Year 2014, at PG&E Midway Substation



Source: PG&E

Candidate Energy Storage Technologies

An energy storage plant of sufficient capacity and duration located at or near Midway substation would make it possible to time-shift significant amounts electric power produced at Tehachapi when electric demand is low, into periods of high electric demand when energy is most needed and valued by the California grid system. This will smooth the wind power profile to best meet California grid system needs. An energy storage plant can also absorb excess wind generation during times of abnormally high wind generation output; this can help with California electric grid voltage regulation or provide other valuable ancillary services to the California electric grid. Current practice is to turn off wind generation equipment during over-generation events to prevent problems with grid stability and high voltages. Having an energy storage capability integrated into the grid will allow valuable wind generation equipment to remain online and still maintain California electric grid reliability.

Grid-scale energy storage technologies have the potential to increase the reliability and "dispatchability" of the California's renewable energy supplies. The smart grid of the future will need energy storage to integrate intermittent renewable generation, provide ancillary services, manage peak demand, and relieve transmission and distribution congestion. From traditional pumped storage plants to smaller-scale distributed battery plants, a portfolio of storage options will be necessary to address different challenges posed by the California grid of the future. Table 1-1 in Chapter 1shows some key metrics for existing energy storage plant options.

The remainder of this section provides an overview of alternative types of energy storage plants.

- **Pumped Energy Storage:** This form of bulk energy storage stores energy in the form of water pumped from a lower elevation reservoir to a higher elevation reservoir. Low-cost off-peak electric power is used to run the pumps. During periods of high electrical demand, the stored water is released and allowed to flow through hydro turbines to generate electricity. Pumped storage is the largest-capacity form of grid energy storage now available. PG&E operates the Helms pumped storage facility. It supplies 1200 MW or about 7 percent of peak resource needs in California. This facility flattens out load variations on the grid, permitting Diablo Canyon Nuclear Power Plant and other large thermal power plants that provide base load electricity 24x7 at their nameplate rating, which enables them to continue operating at peak efficiency. Helms also helps control electrical network frequency and provides spinning reserve capacity for the California electric grid.

  However, pumped hydro plants are difficult to site today. In addition, pumped hydro plants require long construction time periods (for example, about ten years) and are only cost-effective in sizes greater than about 1000 MW's. These plants are expensive to build since capital costs are as high as or higher than $3000/kW. Hydroelectric plants can only operate where suitable waterways exist, and many of the best sites have already been developed. The pumped hydro plant dam and associated facilities, as well as additional required smaller dams, pose high initial capital costs. Also, because topography and environmental concerns are unique at each site, standard plant designs are seldom appropriate or used; thus, each pumped hydro dam complex must be custom-designed, which increases plant capital costs.

- **Compressed Air Energy Storage (CAES):** CAES plants use off-peak electricity to compress air into an air storage system. When electricity is needed, air is withdrawn from the storage system; the compressed air is heated in a recuperator by exhaust from a standard combustion turbine (CT) module, expanded in an expander to predefined conditions, and passed through one or more turbine expanders, where electricity is generated. Conventional CAES plants use about 35 percent of the gas of a combustion turbine (CT) and thus produce about 35 percent of the pollutants per kWh generated by a CT. The compressed air may be stored in several types of underground media, which include saline porous rock formations, depleted gas or oil fields, and salt caverns. The air may also be stored in above-ground vessels or air pipelines. Two CAES plants have been built to date: a 290-MW, 4-hour unit in Huntorf, Germany, built in 1978 and expanded to 330-MW, 4-hour unit in 2008; and a 110-MW, 26-hour unit in McIntosh, Alabama, built in 1991. Both of these plants use underground salt caverns as the air storage media. An advanced concept currently being researched is an adiabatic CAES plant, which would retain the heat produced by compression and return it to the air when the air is expanded to generate electric power. This would eliminate the need for an external energy source, like natural gas, to heat the air during the generation mode of the plant. The heat can be stored in a solid such as concrete or stone, or more likely in a fluid such as hot oil or molten salt. Adiabatic CAES is currently a subject of ongoing R&D study, with no utility scale plants built as of 2010.
- **Battery Storage:** Batteries use reversible chemical reactions to store or release direct current (DC) electrical energy. Battery systems connected to large solid-state converters have been used to stabilize small power distribution networks. A system with a capacity to delivery 20 MW's for 15 minutes at its full discharge level is used to stabilize the frequency of electric power produced on the island of Puerto Rico. A 27-MW, 15-minute nickel-cadmium battery bank was installed at Fairbanks, Alaska in 2003 to stabilize voltage at the end of a long transmission line. Other technologies for large-scale battery storage are vanadium redox flow, liquid metal, and sodium-sulfur batteries. Various types of flow batteries are beginning to be used for energy storage designed to smooth out transient fluctuations in wind energy supply. Vanadium redox flow batteries are currently installed at the Huxley Hill wind farm in Australia (6 MWh) and Tomari Hill wind farm at Hokkaidō, Japan. Sodium-sulfur batteries have been used for grid storage in Japan and in the United States. PG&E is currently in the process to install a 6-MW, 7-hour sodium-sulfur battery at a Hitachi electronics fabrication facility in San Jose, California.
- **Flywheel Energy Storage (FES):** Flywheels store energy by accelerating a rotor (flywheel) to a very high speed and maintaining the energy in the storage system as rotational energy. (Note: The stored energy in a flywheel goes up with square of the rotational speed of the flywheel.) When energy is extracted from the system, the flywheel's rotational speed is reduced; adding energy to the system correspondingly results in an increase in the speed of the flywheel. A FES system uses an electric motor/generator combination to accelerate or decelerate the flywheel rotor. Advanced

FES systems have rotors made of high strength carbon filaments, suspended by magnetic bearings, and spinning at speeds, for example, from 20,000 rpm to over 50,000 rpm in a vacuum enclosure. Such flywheels can come up to speed in a matter of minutes or seconds – much quicker than some other forms of energy storage. Compared to pumped hydro and CAES systems, FES systems typically have small capacities and low power levels – the largest devices are on the order of 50 kWh and 200 kW. The primary advantage of FES systems is their quick response time, which is about 5 ms. They are mainly used to provide load leveling for large battery systems, such as an uninterruptible power supply (UPS) for data centers. Beacon Power Inc. has proposed a large flywheel facility for electric grid up and down regulation.[5] This type of plant would be composed of a 200 high-energy 25-kWh/100-kW flywheels and would be able to provide 20 MW of up and down regulation – a total swing of 40 MW.

- **Superconducting Magnetic Energy Storage (SMES)**: SMES systems store energy in the magnetic field created by the flow of direct current in a superconducting coil that has been cryogenically cooled to a temperature below its superconducting critical temperature. A typical SMES system includes three parts: a superconducting coil, a power conditioning system, and a cryogenically-cooled refrigerator. Once the superconducting coil is charged, the current will not decay and the magnetic energy can be stored indefinitely, as long as the system is cooled to, or below, its superconducting temperature. The stored energy can be released back to the network by discharging the coil. SMES systems are highly efficient; the round-trip efficiency is usually on the order of 95 percent. SMES loses the least amount of electricity in the energy storage process compared to other methods of storing energy. The high cost of superconductors is the primary limitation for commercial use of this energy storage method. A robust mechanical structure is required to contain the very large forces generated by SMES magnetic coils. The dominant cost for SMES is the superconductor, followed by the cooling system and the mechanical structure. Due to the energy requirements of refrigeration, and the limits in the total energy able to be stored, SMES is currently used for short duration energy storage (such as, one or two seconds). Therefore, SMES is most commonly deployed to improving power quality. For large SMES plants to become practical, several technical challenges have to be solved, which are currently subjects of R&D at EPRI and DOE.
- **Super capacitors:** Super capacitors (also known as ultra-capacitors) are DC energy storage devices that must be interfaced to the electric grid with an inverter/rectifier providing 60 Hz output. A super capacitor provides power during short duration interruptions and voltage sags. By combining a super capacitor with a battery-based uninterruptible power supply (UPS) system, the life of the batteries can be extended. The batteries provide power only during the longer interruptions, reducing the cycling duty on the battery. Small super capacitors are commercially available to extend battery life in electronic equipment. Large super capacitors are still in development; and, they

[5] http://www.beaconpower.com/files/SEM_20MW_2010.pdf

may become a viable energy storage option for commercial deployment in the next ten years.[6]

Functional Specification of Needed Energy Storage Plant

In November 2007, the California ISO released a study[7] of the transmission and operating issues associated with achieving a 20 percent Renewables Portfolio Standard (RPS), largely through additions of wind resources in the Tehachapi area. (A California ISO study of issues associated with the higher 33 percent RPS level is in progress.) This study provides some insight into how a grid connected energy storage device will need to operate to provide the most value for the California grid of the near future.

The study consists of several components. The transmission system analysis includes transient stability and post-transient voltage stability of the California ISO grid. The study evaluated wind plant characteristics necessary to achieve acceptable static and dynamic performance on the California grid. The California ISO operational issues analysis included assessment of overall ramping requirements (MW/min), load-following capacity (MW), and regulation capacity. The study also evaluated over-generation issues related to wind production and potential solutions, including the use of energy storage plants to mitigate the grid operational issues.

The study concluded the following:

- An additional 800 MW/hr of generating capacity and ramping capability will be required by the California ISO to meet the multi-hour ramping requirements on the California grid.
- Substantial increases in California ISO regulation procurement (170-250 MW up and 100-500 MW down) will be required.
- There is a need by the California ISO for increased intra-hour load following in the 600 MW to 900 MW range.
- The California ISO morning ramp will increase by 926 MW to 1529 MW; and the California ISO evening ramp will increase by 427 MW to 984 MW, depending on the season.

The California ISO believes that the amount of ancillary services and capacity resources that will be needed for the 33 percent level of RPS would be much higher than for the 20 percent RPS outlined above; the California ISO is currently conducting a study to quantify the ancillary and capacity resources needs.

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6 Source:http://www.energy.ca.gov/distgen/equipment/energy_storage/energy_storage.html#supercapacitor

7 The study and follow-up projects to support its conclusions and extend the analysis can be found on California ISO website at http://www.caiso.com/1c51/1c51c7946a480.html.

Based on the results of this California ISO study and input from EPRI, an energy storage plant connected at or near the Midway Substation must have the following minimum capabilities:

- Minimum capacity of 100 MW's.
- Minimum of 5 to 6 hours of energy absorption and delivery to time-shift significant amounts of energy.
- Minimum response time to full output of 15 minutes, to provide ramping, load following, and regulation services to the grid.
- Can be used to complement other existing technologies such as pumped storage.
- Should have siting flexibility.
- Use proven technology with commercial components that are readily available.
- Should have future expansion capacity or increased performance.
- Have minimum cost.

Using these criteria, Table 2-3 compares the various energy storage technologies that can meet these capabilities.

Metric Tool Analysis Results

One of the goals of this report is to implement tools that can be used to assess the economic value of energy storage plants and assist in determining the optimum energy storage technology that can be used near wind energy sites. This will help mitigate possible negative impacts caused by integrating increasing amounts of wind energy into PG&E's transmission networks.

Table 2-3: Selection Criteria for Existing Storage Technologies

Storage Technology	Pumped Hydro	Compressed Air (CAES)		Battery[8]	Flywheel	SMES	Super-Capacitors
		Underground	Above Ground				
	← Larger Scale (Grid) - Smaller Scale (Distributed) →						
> 100 MW Capacity	Yes	Yes	No	No, largest battery is currently 27 MW	No, not in foreseeable future		
> 5 Hours Storage Capacity	Yes	Yes	Yes	Yes, NAS and Flow technology up to 7 hours	No		
< 15 minute Response Time to Full Output	Yes	Yes	Yes	Yes	Yes		
> 85 Percent AC to AC Conversion Efficiency	Yes	Yes	Yes	Yes, Depends on specific technology, Most > 85 percent, Lead Acid 70 percent	Yes		
Proven Technology	- Many large units installed worldwide - Uses exiting hydro turbine technology	- Uses commercially available turbo machinery and compressors - Two installed units: 290 MW/4 Hr plant in Germany built in 1978; 110 MW/26 Hr Alabama plant built in 1991	- No installed units - Same infrastructure as underground CAES - Addition of above ground air storage infrastructure	- No installed units above 27 MW - Lead acid is well established - Limited experience with other battery technologies - Limited experience with multi-MW installations	- No installed units above 1 MW - New technologies, still largely in development phase		

Source: EPRI

[8] Includes lead acid, sodium sulfur, flow, small cell lithium-ion and advanced large cell lithium-ion batteries.

Table 2-3: Selection Criteria for Existing Storage Technologies (continued)

<table>
<tr><th rowspan="3">Storage Technology</th><th rowspan="2">Pumped Hydro</th><th colspan="2">Compressed Air (CAES)</th><th rowspan="2">Battery [9]</th><th rowspan="2">Flywheel</th><th rowspan="2">SMES</th><th rowspan="2">Super-Capacitors</th></tr>
<tr><th>Underground</th><th>Above Ground</th></tr>
<tr><th colspan="7">← Larger Scale (Grid) - Smaller Scale (Distributed) →</th></tr>
<tr><td>Siting Requirements</td><td>- Requires reservoir site of sufficient volume and height
- Increasing environmental restrictions for dams</td><td>- Uses abandoned oil or gas wells, mines or similar geologic structures</td><td>- Storage infrastructure can take up large area</td><td>- Batteries and infrastructure can take up large area</td><td colspan="3">- Current low power/low energy units are compact
- Proposed multi-MW scale units would require large areas</td></tr>
<tr><td>Upgradeability once installed</td><td>Replace turbines with more efficient units</td><td colspan="2">Increase operating pressure
Incorporate adiabatic heat storage technology</td><td>Add batteries to increase capacity and/or duration</td><td colspan="3">Add units to increase capacity and/or duration</td></tr>
<tr><td>Total Capital[10] Cost ($/kW)</td><td>2,100</td><td>600-750</td><td>1,300-1,550</td><td>1,740-3,650</td><td>3,695-4,313</td><td>380-489</td><td>300-450</td></tr>
</table>

Source: EPRI

Using the procedure described in Section 1 of this report, EPRI performed the metric-based analysis for PG&E's Midway Substation. Based on the input data, this analysis concluded that a below-ground compressed air energy storage (CAES) plant is the lowest cost energy storage plant (see Figure 2-5). The cost lines in Figure 2-5 show the levelized cost (includes capital and operating costs) for the various candidate energy storage plant options. Since CAES using underground air stores have the lowest levelized cost, it is the recommended energy storage technology to deploy at the Midway Substation.

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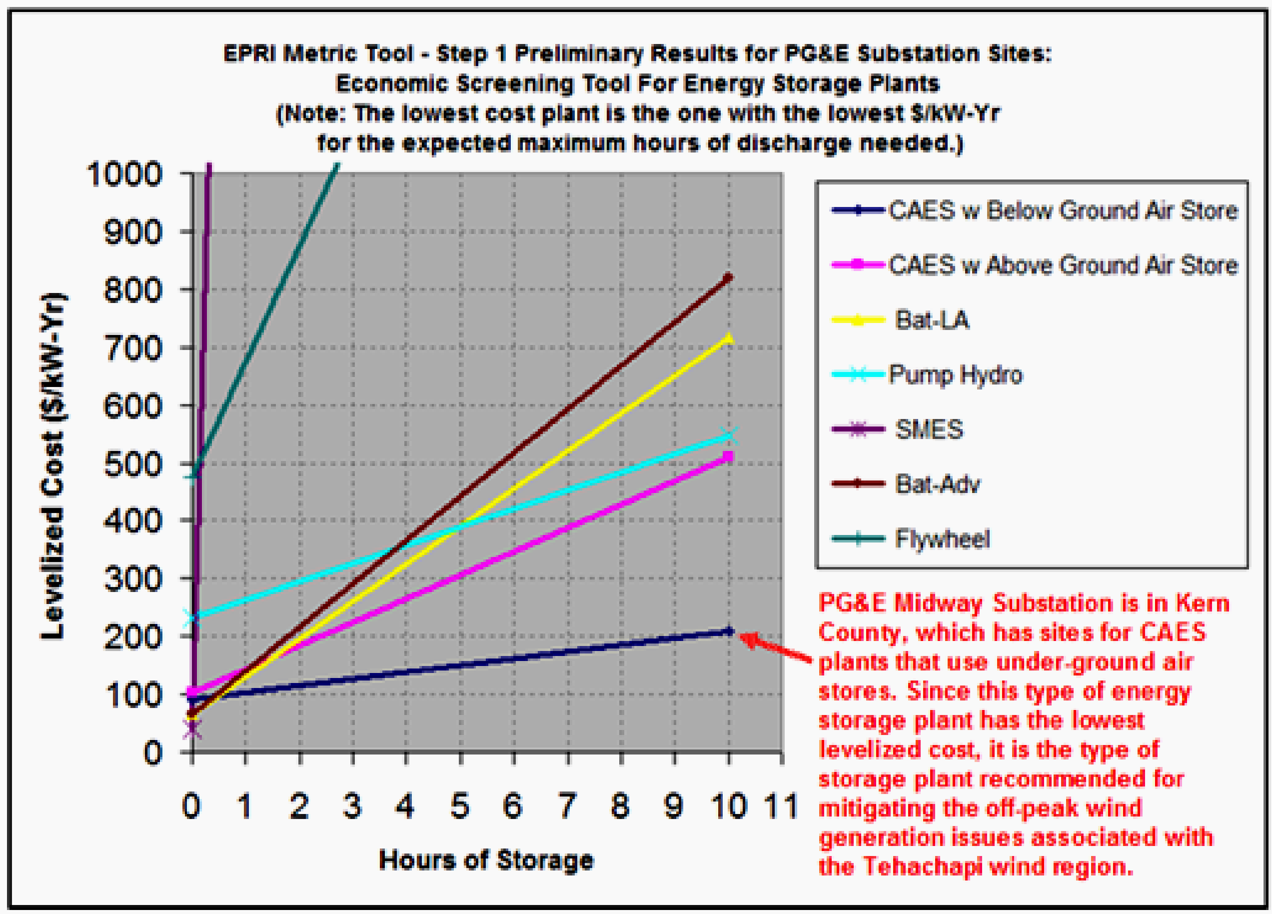
[9] Includes lead acid, sodium sulfur, flow, small cell lithium-ion and advanced large cell lithium-ion batteries.

[10] Cost information from EPRI.

Figure 2-5: Preliminary Results of Metric-Based Analysis for PG&E Midway Substation



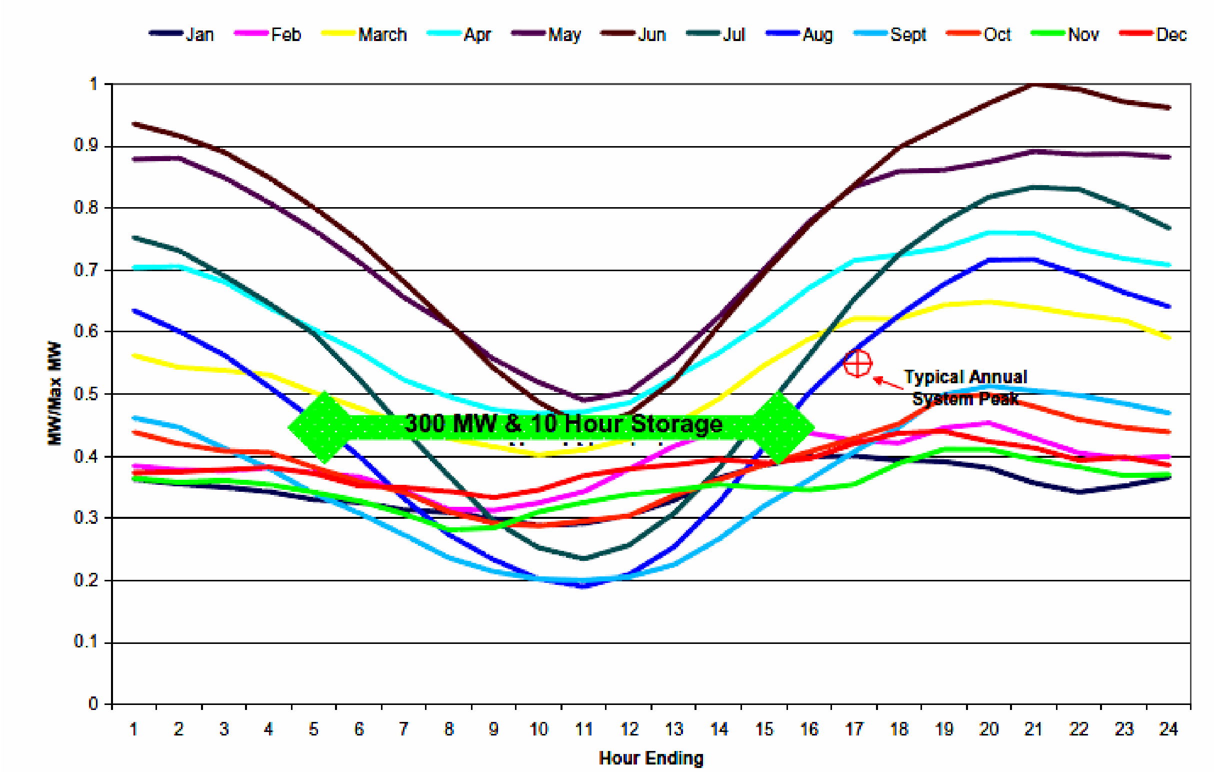
Source: EPRI

Working closely with PG&E, EPRI then continued the DYNATRAN analysis to specify the plant capacity and duration of storage capability. Based on the team's experience with these analyses, coupled with DYNATRAN analyses, EPRI concluded that a 300-MW CAES plant using an underground air store with 10 hours of storage would be optimum.

Energy Storage Plant Selected

Figure 2-6 shows how such a plant would operate with the Tehachapi wind resources. The CAES plant would be discharging (generating electricity) from approximately hours 5 through 15, when wind variability is the greatest and electricity loads are the highest. Conversely, during off-peak hours, when wind variability and electricity loads are lower, the wind power will be used to charge the storage reservoir.

Figure 2-6: Average Tehachapi Monthly Wind Production, Ratio of Actual to Max Output, and CAES Discharge Period

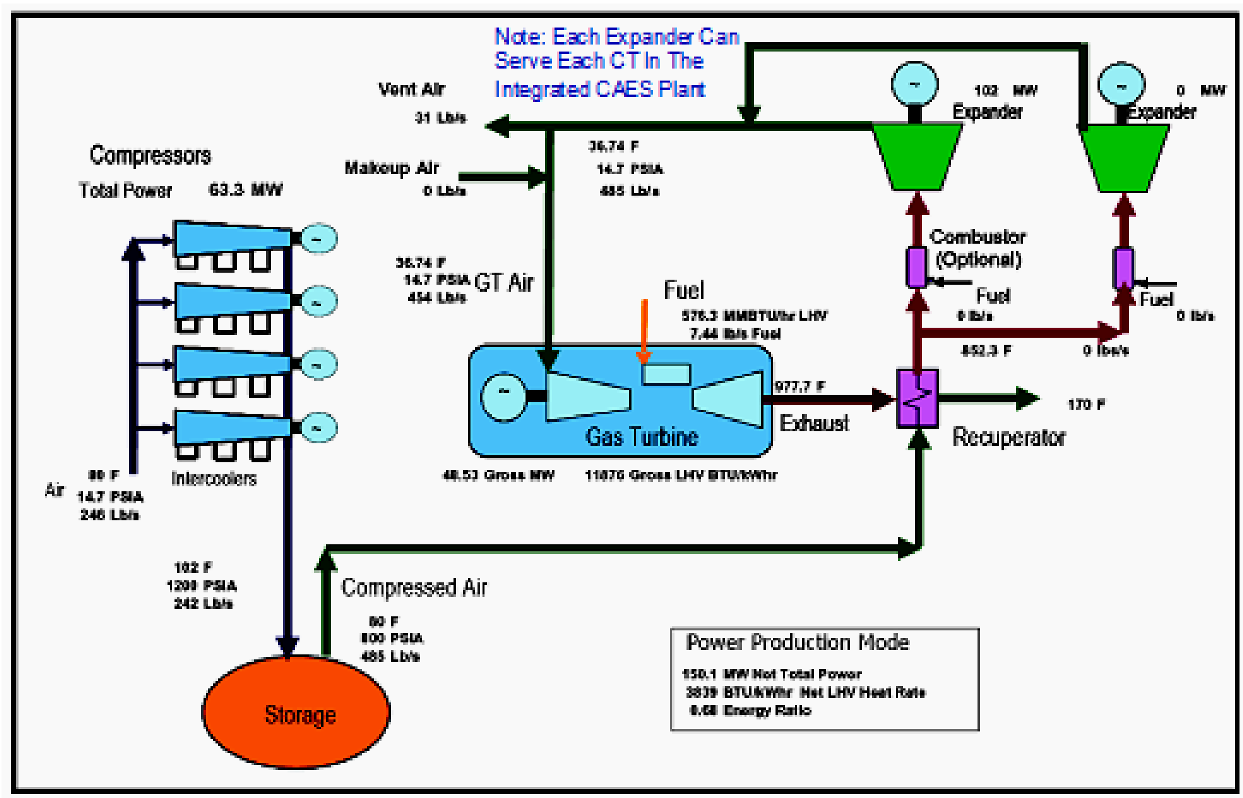


Source: EPRI

Figure 2-7 shows a plant schematic design for a 300-MW, 10-hour CAES plant using a below-ground reservoir. The most flexible and reliable configuration chosen for the proposed PG&E plant consists of two identical 150-MW plant modules using the so-called CAES "chiller option." Each module operates separately, but reliability and availability are greatly improved because their compressor and expander units are interchangeable.

In this second generation CAES plant, air is compressed at night to charge an underground air storage reservoir. A dedicated electric motor drives the intercooled compressor. During the day, a regulating valve releases air from the underground air store at a specified constant pressure. This air is then preheated via a heat exchanger/recuperator using the exhaust of a standard combustion turbine (CT) module, which increases the temperature of the compressed air coming from the air storage reservoir. An additional option for the plant is a duct burner that uses a small amount of natural gas to keep the recuperator warm. Keeping the recuperator warm when the CAES plant is not generating reduces plant start time and enables the plant to perform ramping and frequency regulation duty when it is not used during arbitrage duty cycles. The improved start time of 6-7 minutes qualifies the plant for spinning reserve status, which provides additional financial benefits. Hence, the project staff recommends this plant option for its design. The hot, compressed air from the recuperator is then passed through an expander to generate about twice the amount of power as is delivered from the CT. Note that the second expander shown in Figure 2-7 is the expander for the second 150-MW module. It is shown here to illustrate the ability to cross-connect the plant expander from the second 150 MW plant module of the first 150 MW plant module.

Figure 2-7: PG&E CAES Plant Schematic Design Using Below-Ground Storage for First of Two 150 MW Plant Modules



Source: EPRI and ESP

The expander is designed to output air at a defined temperature and pressure conditions, guaranteeing the CT input air at a constant, cooled temperature level regardless of the ambient temperature air conditions. This avoids any derating of the CT portion (and hence the entire CAES plant) during hot summer conditions. Without this control of input conditions, hot weather (and potentially operation at altitude) coincident with high peak loads would derate the output of the CT component of the CAES plant during those on-peak summer time periods when maximum plant output is needed. Note that this cycle is called a “chiller option” because the output air from the expander is “chilled” during the pressure drop that occurs during the air pressure expansion process.

The exhaust air from the expander is then fed to the CT, which provides the remaining portion of the CAES plant’s gross output. It should be noted that the chiller type of advanced CAES plant design and technology is described in U.S. Patent Numbers 7389644 and 4872307 and was invented by Dr. Michael Nakhamkin, Chief Technical Officer of Energy Storage and Power LLC (ESPC), a subsidiary of Public Service Electric and Gas.

By working with PG&E staff familiar with their natural gas storage facilities and potential CAES underground air storage media, EPRI has determined that there are potential sites for CAES plant that can connect into the Midway Substation.

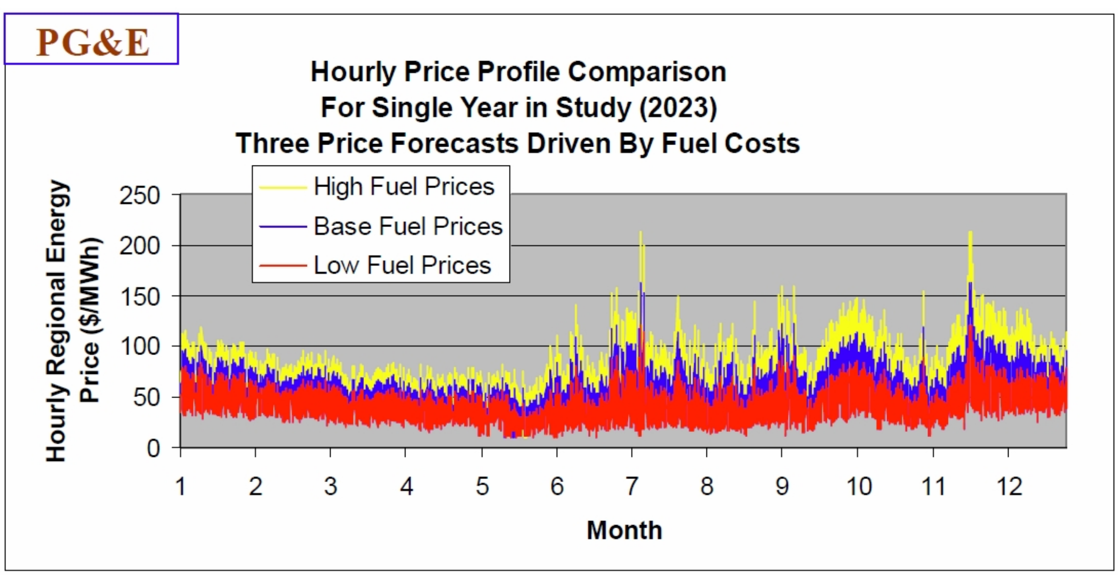
DYNATRAN Economic Analysis of the CAES Plant

EPRI performed a DYNATRAN economic analysis of the recommended CAES plant with the following specifications:

- A CAES plant that uses an underground air store in PG&E's Service Territory near its Midway substation where large amounts of wind energy is produced.
- 300 MW maximum discharge capacity.
- 215 MW maximum charge capacity (Note: This enables one hour of compression to produce one hour of generation.)
- 10 hours of stored energy (for example, 300 MW for 10 hours will produce 3000 MWh of energy.)
- 4229 Btu/kWh (HHV) heat rate during the discharge cycle of the plant.
- 0.7 MWh electric energy input per 1.0 MWh's of plant energy output during discharge.
- $3.5/MWh variable O&M.

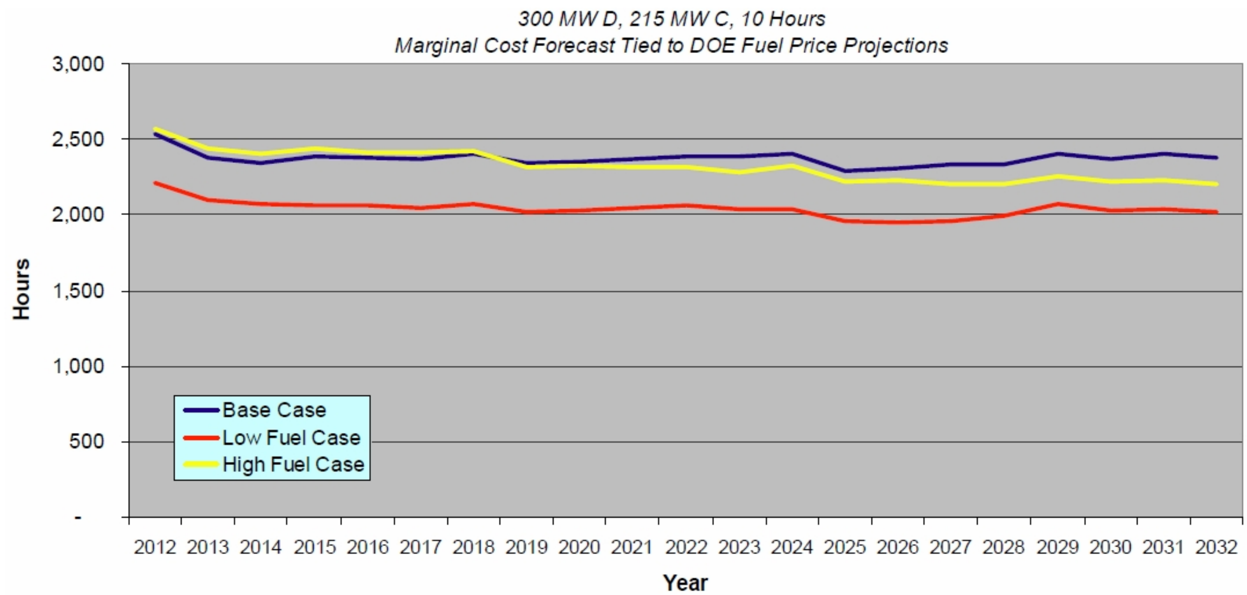
The simulation assumes a economic study period from 2010 through 2032. CAES will be dispatched to use relatively low cost, off-peak electric energy to displace relatively high cost, on-peak electric energy (for example, an "arbitrage" duty cycle). For the input data specified in section 1 and these assumptions, the analysis first determined hourly electricity prices for each of the three natural gas price forecasts (see Figure 2-8).

Figure 2-8: Hourly Electricity Prices by Scenario for PG&E



DYNATRAN then calculated the annual hours of storage discharge for energy arbitrage in the three scenarios (see Figure 2-9). This is the number of hours that the CAES plant is generating at a capacity at or above its minimum capacity.

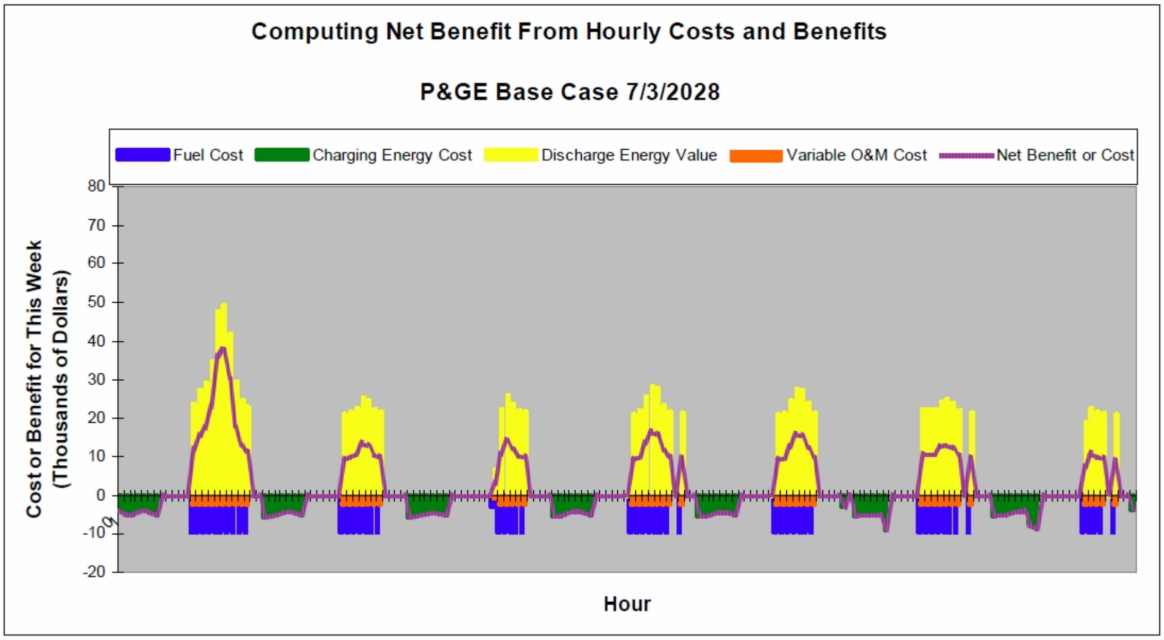
Figure 2-9: Annual Hours of Discharge for Energy Arbitrage (PG&E) CAES Plant



Source: EPRI

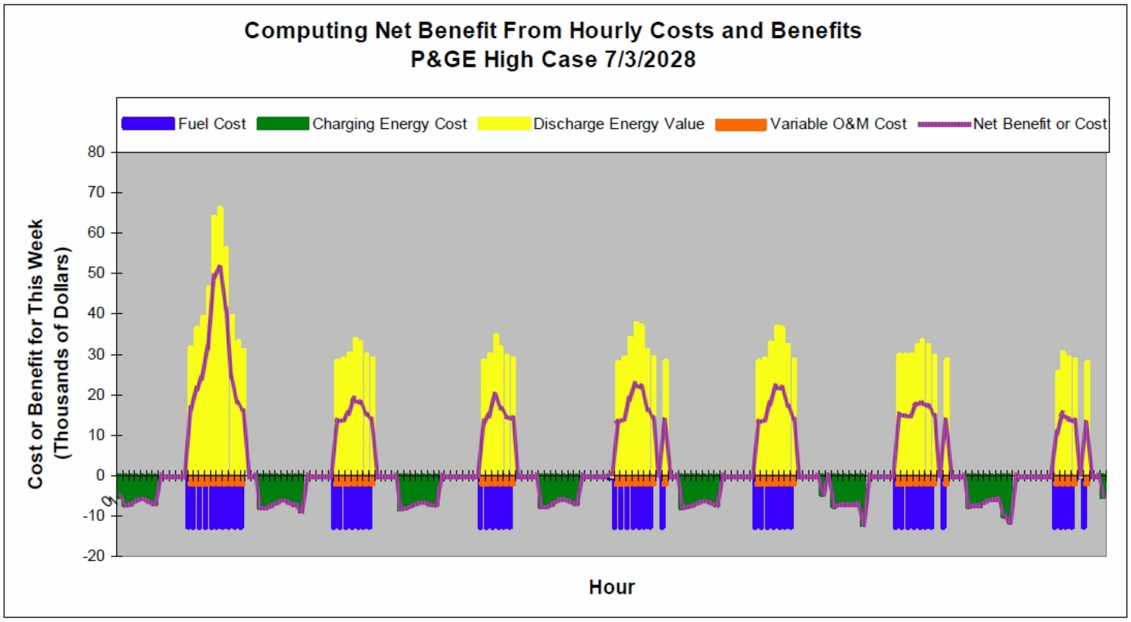
DYNATRAN then calculated the hourly storage economics by computing the net benefit from hourly costs and benefits. Figures 2-10, 2-11, and 2-12 show the results for a sample summer day (July 3, 2028) for the base case, high case, and low case, respectively. Costs include fuel costs, charging energy costs, and variable O&M costs. The benefit is the discharge energy value.

Figure 2- 10: Hourly Storage Economics for PG&E Base Case on 7/3/28



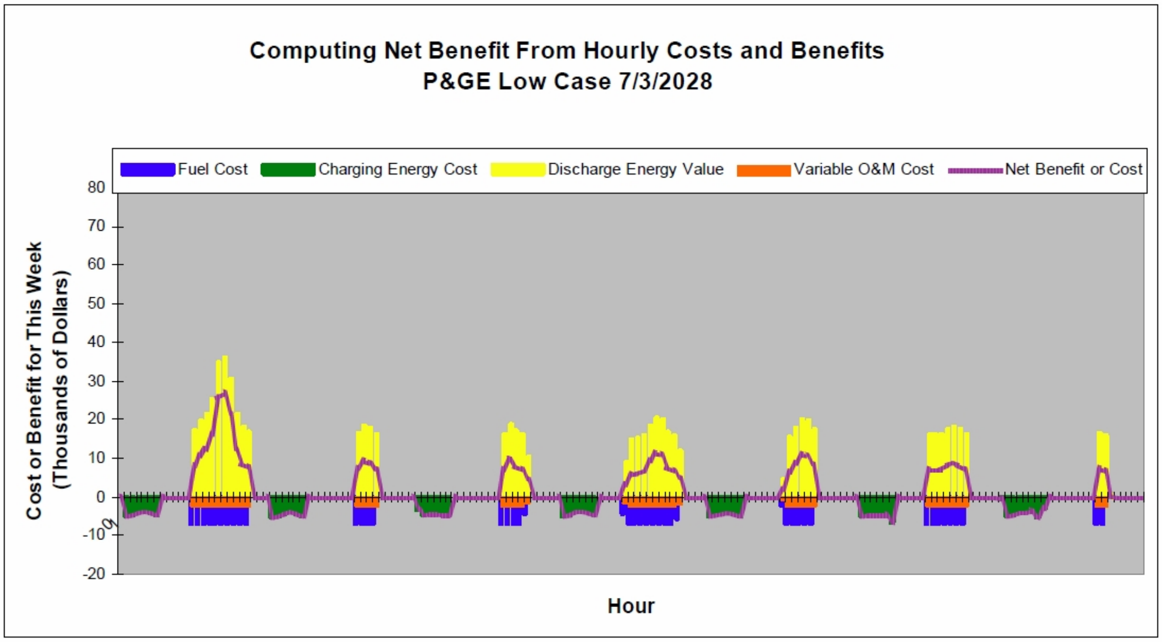
Source: EPRI

Figure 2- 11: Hourly Storage Economics for PG&E High Case on 7/3/28



Source: EPRI

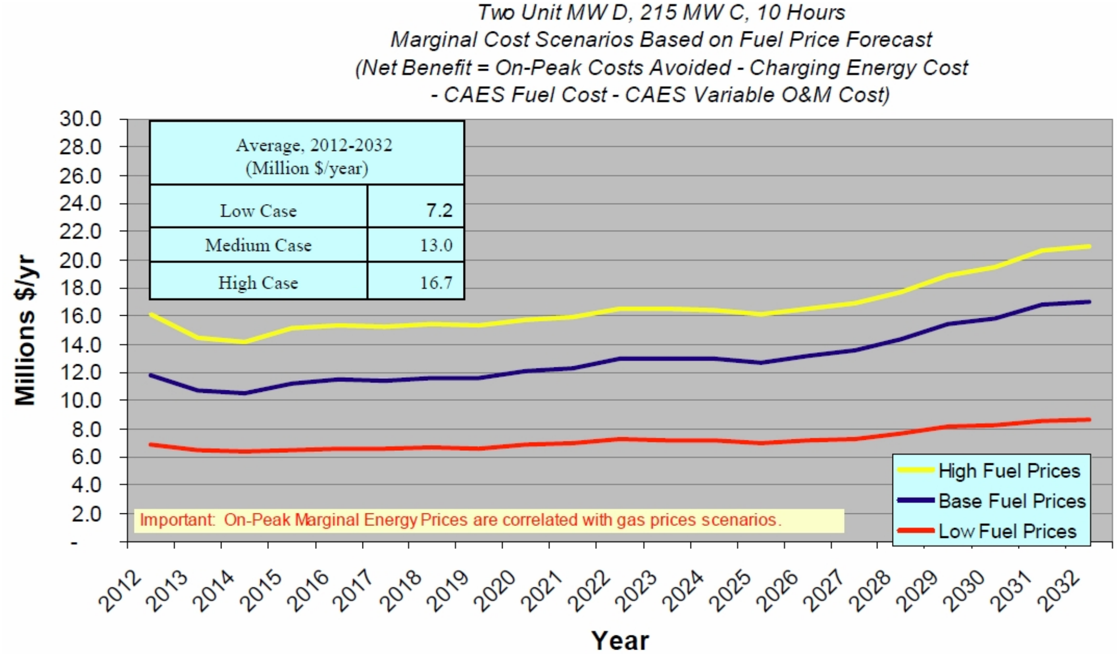
Figure 2-12: Hourly Storage Economics for PG&E Low Case on 7/3/28



Source: EPRI

Figure 2-13 compares the net annual economic benefit from energy arbitrage under the three fuel price cases. Note that these values do not account for an annual capital cost. They are the net operating benefit. The average annual benefit over the study period is $7.2 million in the low fuel price scenario, $13 million in the base case scenario, and $16.7 million in the high case scenario.

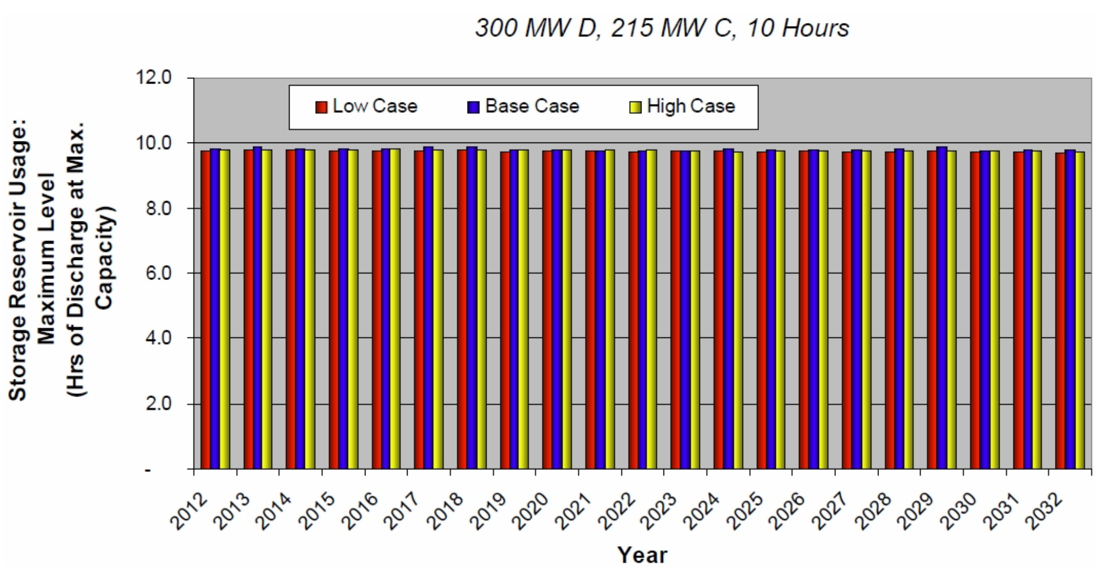
Figure 2-13: Comparison of Net Economic Operating Benefit Under the Three Fuel Price Cases



Source: EPRI

Figure 2-14 shows the storage reservoir use as a function of price scenario. These values are annual averages of weekly usage of the reservoir for energy arbitrage. This shows that reservoir use is insensitive to the price scenario due to the fact the plant attempts to run as often as it can and is only limited by how many of hours of storage are available to use.

Figure 2-14: Storage Reservoir Use as a Function of Price Scenario



Source: EPRI

The project team then addressed benefits that accrue from the ability of the CAES plant to provide benefits from capacity and ancillary services. As such, the capacity-oriented benefits considered in this analysis include the following:

- **Capacity Credit.** If online for a minimum number of hours per day, the CAES plant can provide capacity benefits, which can be valued at either the energy price for firm capacity, in the California ISO environment, or the cost of alternate capacity, in a system planning situation.
- **Ramping Benefit.** Storage units usually have capacity available in shoulder hours and can support a generation system as large units ramp up and down, at their rate, which is slower compared to a CAES plant. Ramping benefits are not likely to add directly to arbitrage benefits; instead, they may offer a higher-profit market for a storage plant operating in shoulder hours.
- **Black Start Capability.** CAES can reach full output from an off-line state in minutes, without outside support, which qualifies it for black-start credit, where applicable.

Other benefits considered in this analysis include the following:

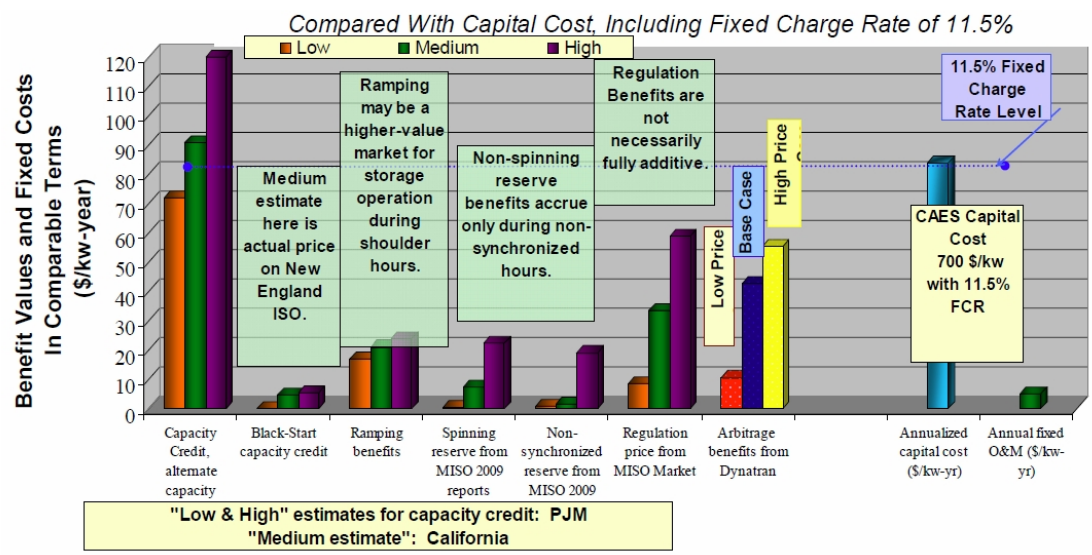
- **Spinning Reserve Credit.** CAES provides spinning reserve whenever either charging or discharging. In charging mode, spinning reserve available is the full discharge capacity plus the charging level in that hour. In the discharging mode, the synchronous spinning reserve available is the difference between full discharge capacity and the discharging level in that hour.
- **Non-Synchronous (Quick-Start/Ready) Reserve Credit).** CAES can start up in less than 10 minutes and thus can satisfy any nonsynchronous reserve requirement. Credit can be applied in any hours CAES is not already synchronized for either charging or discharging.
- **Frequency Regulation.** When on-line, CAES unit operation is flexible enough to assist with maintaining frequency on the system.
- **Avoiding Curtailment Payments.** An important application of storage is to prevent the curtailment of wind energy. Curtailment costs were uncertain from PG&E's perspective, so an estimate based on wind energy contract prices is made for comparison purposes.

Currently, California has no active market prices for these services, but it is expected such market prices will be instituted in California during the study period for this analysis (for example, 2012 to 2032). Thus, the potential exists for the CAES plant to provide benefits in each of these benefit categories. The project team estimated the value for these benefits using replacement capacity costs and ancillary services markets elsewhere in the US. For comparison, the overnight cost of a combustion turbine (CT) was assumed at $969/kW (2009 dollars) and the CT's fixed O&M cost was assumed at $11.33/kW-year (2009 dollars). Further, to incorporate the cost of capital, the analysis assumed a cost of capital reflecting current California utility return-on-equity requirements of 11.5 percent.

Figure 2-15 compares the benefits from these capacity- and energy-related ancillary services, the arbitrage benefits, and the annualized cost and annual fixed O&M costs. The benefits are shown in $/kW-year for each of the three fuel price scenario cases. As shown in Figure 2-15, capacity and ancillary service benefits can be significantly larger than benefits from arbitrage alone.

Figure 2-15 also shows that while arbitrage alone may not be sufficient to cover the annualized CAES capital and O&M costs, the inclusion of capacity and ancillary service benefits can provide a significant net benefit, depending on the fuel price scenario.

Figure 2-15: Potential Economic Benefits Including Typical Capacity Values and Actual 2009 Ancillary Services Prices



Source: EPRI

CHAPTER 3: EPRI-SCE Wind, Transmission, and Energy Storage Analysis

Introduction

Southern California Edison (SCE) has worked closely with EPRI to study the deployment and impact of wind energy on portions of its electric grid system. The goal is to identify viable advanced storage strategies and locations that will enable California to reach renewable policy goals and enhance the integration of wind on the California transmission system.

Despite a number of existing wind farm facilities throughout California and a growing number of wind projects in various stages of development, several challenges increase the complexity of integrating wind energy with non-renewable systems. The economic and operational impacts of integrating wind generation are expected to increase as more wind farms interconnect with the Western Electricity Coordinating Council (WECC) grid. To ensure continued system reliability and financial solvency, these impacts need to be thoroughly studied and proper mitigation strategies need to be developed to address any potential operational issues resulting from the integration of the growing number of wind facilities. The collaboration of a major utility, EPRI, and an established wind facility developer provide the vision and expertise necessary to conduct this study. The EPRI team expects this study to identify the most viable methods for utilizing projective penetration of wind energy and integrating wind-storage into an existing power system.

The primary intent of the SCE portion of this project is to conduct a detailed feasibility and analysis study of existing wind interconnection locations throughout the SCE system that could benefit from the use of storage devices. SCE's service area is home to the state's most productive sites for wind and solar generation. This includes the Tehachapi Wind Resource Area (TWRA), where up to 4500 MW of wind resources will come online by 2015. The effective cultivation of these wind resources – enabled in part by energy storage plants – will help SCE meet California Renewable Portfolio Standard (RPS) goals and establish replicable methods and tools for broader national utilization when analyzing similar situations where wind resource deployments are growing.

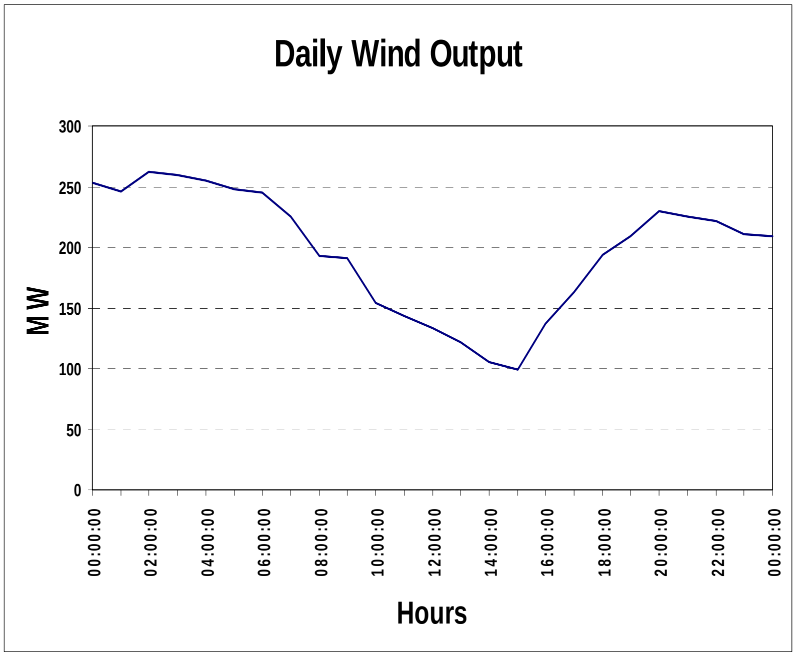
Candidate Energy Storage Sites

The project team focused on the SCE Antelope-Bailey 66-kV grid network subsystem to address prevention of wind generation curtailment. Part of the TWRA, the Antelope-Bailey 66-kV subsystem serves the Antelope Valley, Gorman, and Tehachapi Pass. The system is located approximately one hundred miles northeast of Los Angeles (see Figure 3-1). The system has a nameplate wind generation capacity of 380 MW, with a registered peak coincident generation of 310 MW (see Table 3-1). Figure 3-2 shows the fluctuation of the wind generation in this area over a typical day. There are also two hydroelectric stations with a total of 34 MW of generation capacity. This SCE grid subsystem can be broken down into two main areas: north and south. The north part of the SCE system, where the wind and hydro generation is installed, has a small local load – mainly industrial cement plants. At peak power output from the wind farms, three 66-kV transmission lines connected directly and indirectly to the Antelope 66/230-kV substation transmit the energy to the south part of the SCE bulk system (see Figure 3-3).

Figure 3-1: Antelope-Bailey 66-kV System Geographical Location

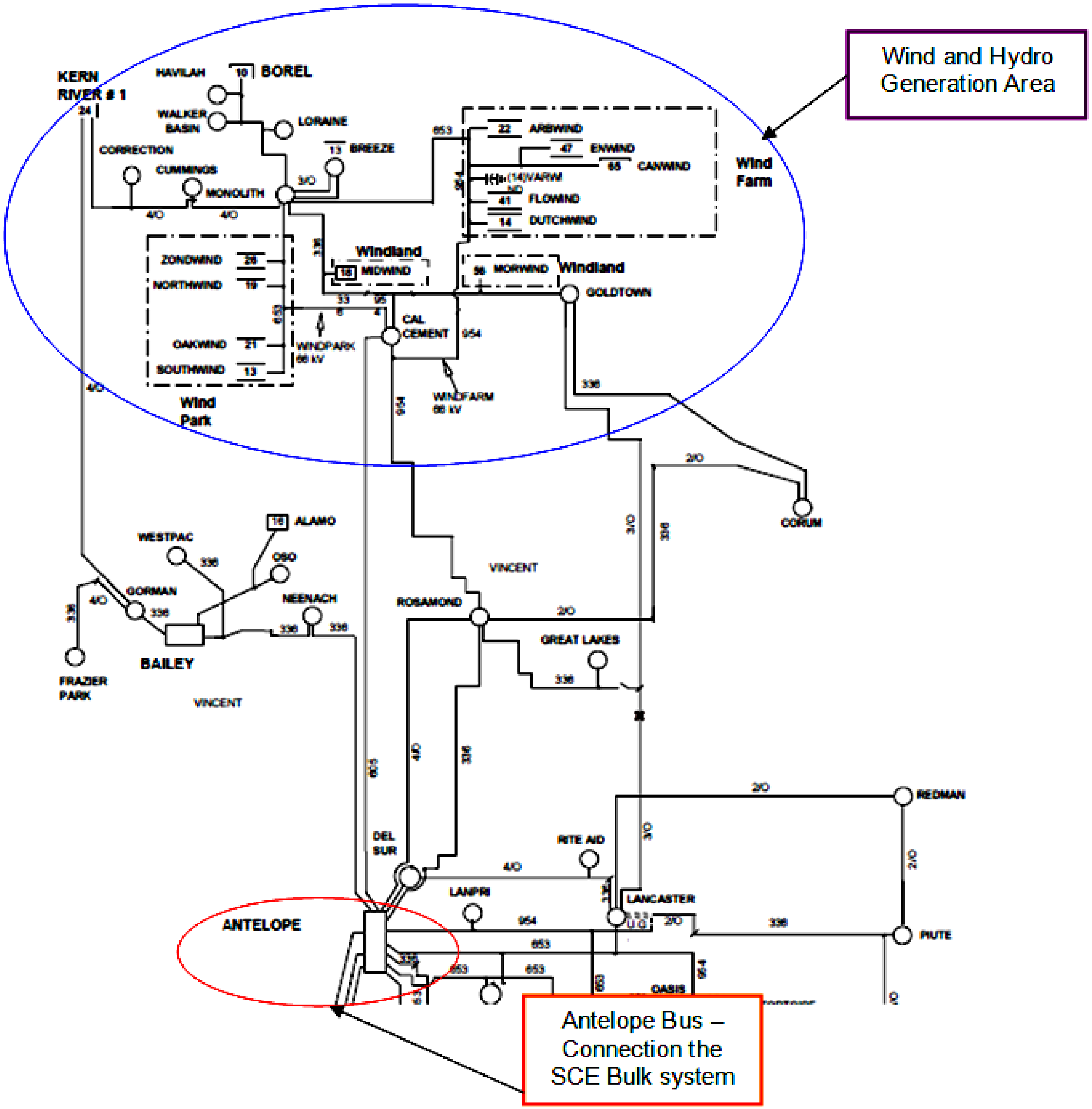
Source: Google Maps

Figure 3-2: Typical Daily Loading During Wind Generation Season at the Antelope-Bailey Grid Network Subsystem



Source: SCE

Figure 3-3: Antelope-Bailey 66-kV Subsystem One-Line Diagram



Source: SCE

Table 3-1: Wind and Hydro Generation Capacity in the Antelope-Bailey 66-kV Subsystem

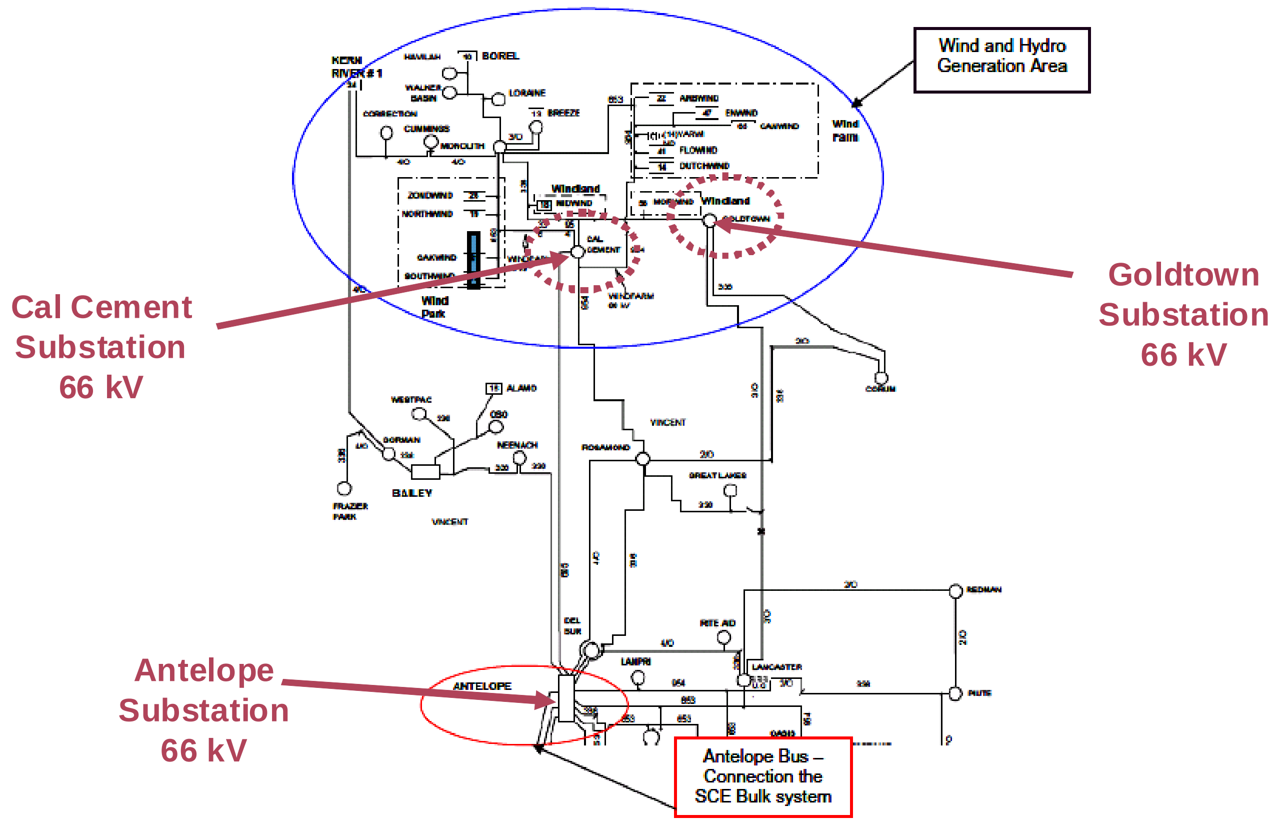
Location	Nameplate	On-Line	Coincident Output MW	Coincident Output MVAR
Arbwind	21.8	21.8	14.8	-4.7
Canwind	65.0	65.0	60.9	-21.1
Enwind	47.1	47.0	47.1	-13.5
Flowind	40.8	40.6	40.8	-11.5
Dutchwind	14.0	13.8	11.4	-2.8
Northwind	19.4	19.0	13.0	-5.0
Oakwind	21.1	21.1	21.1	-5.2
Southwind	13.4	13.4	13.4	-2.1
Zondwind	26.0	25.1	17.1	-7.4
Breeze	12.5	10.5	7.3	-4.1
Midwind	18.0	11.1	9.3	-4.5
Morwind	56.0	55.5	53.9	-15.8
Total Wind	355.1	343.9	310.1	-97.7
Kern River	24.0	24.0		
Borel	10.0	10.0		
Total Hydro	34.0	34.0		
Total	**389.1**	**377.9**	**310.1**	**-97.7**

Source: SCE

Final Sites Selected

Due to the unpredictable and uncontrollable nature of wind conditions at any given moment, energy output from wind farms varies greatly. It is well documented that the variability and availability of wind directly impacts the voltage stability and power transferability (path congestion) of wind generators. SCE's Antelope-Bailey system suffers from most of the issues associated with the intermittences of wind generation. The substation sites selected for this study, the Cal Cement and Goldtown substations, are considered primary points of interconnection to wind generation in the SCE grid network system. These electric busses transmit power along three transmission lines to the Antelope/SCE bulk system; each is susceptible to overloading, making Cal Cement and Goldtown ideal candidates for this study (see Figure 3-4).

Figure 3-4: Antelope-Bailey 66-kV System One-Line Diagram Showing SCE Cal Cement and Goldtown Substation Sites)



Source: SCE

There are two line overloading conditions that require curtailment of wind generation on the Antelope-Bailey subsystem grid. The first condition for curtailing wind is due to the fact that under high wind generation and low loading, one of the main 66-kV transmission lines experiences an overloading above a normal rating. The second reason for curtailment is an N-1 condition or loss of a transmission line that results in a transmission line overloading. The amount of wind generation curtailment is based on system conditions, where various levels of curtailment are set to achieve safe line loading levels.

In order to prevent the overloading of the transmission system, wind generation curtailment is required. The curtailment is based on loading of the Goldtown-Lancaster 66-kV line (with a normal loading of 450 amps and emergency loading of 610 amps) during normal conditions and the loss of the Antelope-Cal Cement 66-kV line. During normal system conditions (high wind generation and low local load) that results in the overloading of the Goldtown-Lancaster 66-kV line, there are three main curtailment levels. These begin with Flowind wind farm (a 28-MW curtailment); the second level is a 13-MW curtailment at Flowind wind farm; and the third level is a 47-MW curtailment at Endwind wind farm. If the overloading persists, 10 MW must be curtailed at all 11 wind farms in the system (see Table 3-2).

Table 3-2: SCE Transmission Curtailment Due to Wind Generation (10 MW at Each of 11 Wind Farm Substations)

10 MW Decrease in Generation at:	Loading Relief on Goldtown – Lancaster line (amps):
Morwind	-19.8 amps
Midwind	-15.9 amps
Dutchwind/Flowind	-15.5 amps
Canwind/Enwind	-15.4 amps
Arbwind	-15.4 amps
Southwind/Oakwind	-15.3 amps
Zondwind/Northwind	-15.2 amps

Source: SCE

In the case of the loss of the Antelope-Cal Cement 66-kV line, 10 MW at all wind farms is required to reduce the overloading of the Goldtown-Cal Cement line.

The system conditions have being identified by SCE's Transmission Planning and System Operations Groups using the Positive Sequence Load Flow program (PSLF). The load flow program shows that the case cannot be solved if the Antelope-Cal Cement 66-kV line is lost, wind generation is at its peak, and low local loading conditions exist. This was demonstrated in a particular PSLF case for a 84-MW flow on the Antelope-Cal Cement line during normal conditions. When the line was opened on the PSLF program, the network stability numerical analysis case did not solve and diverged, indicating the inability of the grid system to operate under this condition, which justifies wind generation curtailment.

An SCE System Operating Bulletin regarding Antelope Bailey requires the curtailment of 110 MW of generation (10 MW per wind farm) at peak generation and low local system load to prevent line overloading. SCE has to pay for this energy must-take whether the energy is consumed or not. Having already determined that energy storage plants could be used to replace the practice of curtailing wind generation at its 66/230-kV Antelope Bailey grid system, SCE welcomed the opportunity to validate the installation of energy storage plants at the utility's two gateway busses as a viable alternative to curtailment.

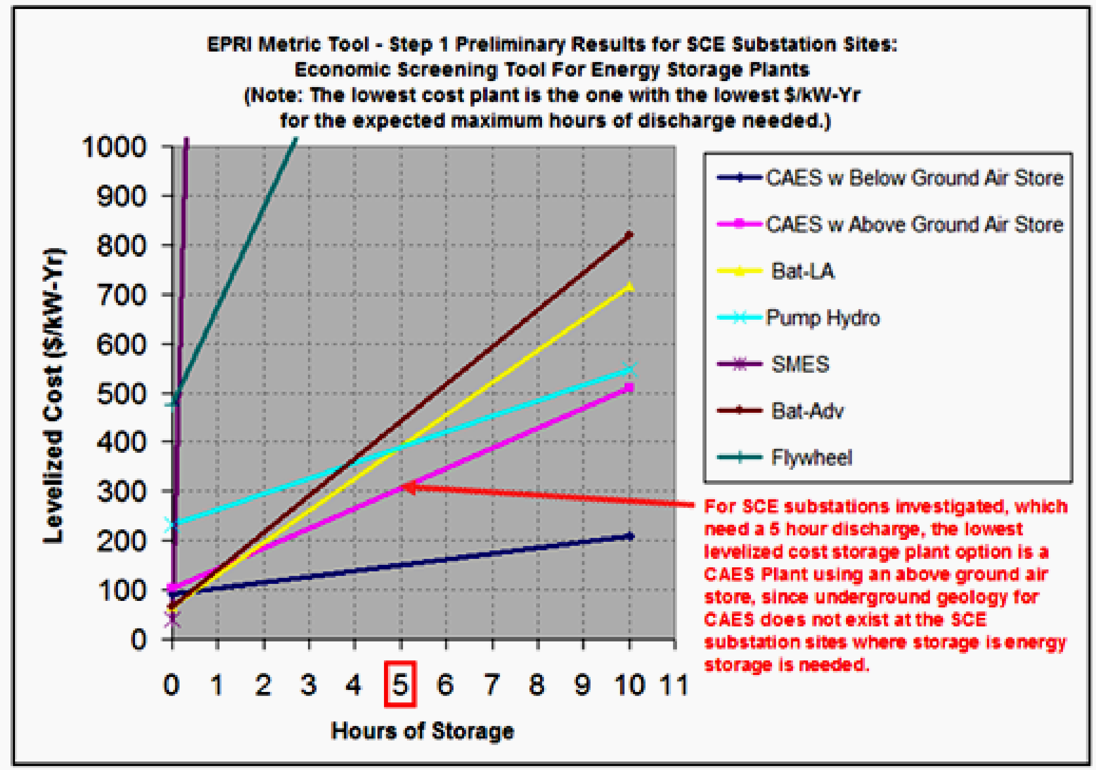
Candidate Energy Storage Technologies

Most available energy storage plant solutions that can handle storage capacity for the two chosen locations were deemed to be infeasible – they would be unreasonably large and very costly. However, the CAES technology proved to be the only cost-effective and commercially viable technology to meet this need.

Metric Tool Analysis Results

The project team analyzed empirical data, and drew upon past experience to determine that approximately 5 hours of storage was needed at the substation sites investigated (for example, Cal Cement and Goldtown). The project team then used DYNATRAN to determine the levelized costs of various energy storage technologies. This analysis indicated that CAES using underground air storage would be the least-cost solution. However, since a suitable below-ground reservoir could not be identified in the area, the second lowest cost solution – CAES using above ground air storage – was identified as the least-cost, most cost-effective and commercially viable solution (see Figure 3-5).

Figure 3-5: EPRI Metric Tool Preliminary Results for SCE



Source: EPRI

Functional Specification of Needed Energy Storage Plants

CAES plants using above-ground air storage integrate equipment and processes commonly used in both the power generation and the oil and gas industries. The size and design of the CAES plant can be tailored to local generation and demand needs. As with most generation projects, many factors need to be considered when selecting and designing a plants major equipment and subsystems. The integration of each of these components must accommodate the manner in which the performance of one set of equipment and processes affects the design and selection of another set of equipment components and processes. Some design considerations/assumptions for the advanced CAES plant used in this analysis are:

- The air store is sized for the quantity and pressure of air needed to power the expansion turbine over a given time duration.
- The compressors are sized to perform air compression within a given time frame.

- The recuperator and expander are sized to transfer and use, respectively, exhaust heat from the combustion turbine.
- The combustion turbine is selected from existing commercial models based on its ability to burn available or specified fuels, and its contribution of output within the integrated system to match the specified power output of the plant.
- The expansion turbine is similarly sized and selected to contribute capacity to match the specified power output of the overall CAES plant.
- The size and performance selection of the major components (such as the compressors, combustion turbine, and expansion turbine) are based on standard manufacturer offerings to the greatest extent possible, to reduce capital cost expenditures.
- The design life of all major plant components is 35 years.

Energy Storage Plant Selected

The project team determined with some certainty that installing two CAES plants for a combined 110 MW of storage capacity, one at Cal Cement and the other at Goldtown, would indeed satisfy the California ISO System Operating Bulletin requirements for reducing overloading on the lines, and hence, eliminate the need to curtail wind generation to the Antelope Bailey system. In order to reduce the impact on the regional grid networks , SCE and EPRI recommends placing a 70-MW, 5-hour CAES storage plant at the Cal Cement 66-kV Substation, and a 40-MW, 5-hour CAES storage plant at the Goldtown 66-kV Substation. The total energy storage capacity is based on the amount of total curtailment under worse case conditions of 10 MW at each of the 11 wind farms in the local grid subsystem. This means the utility lowers its energy must-take costs, which translates into savings for the California ratepayer.

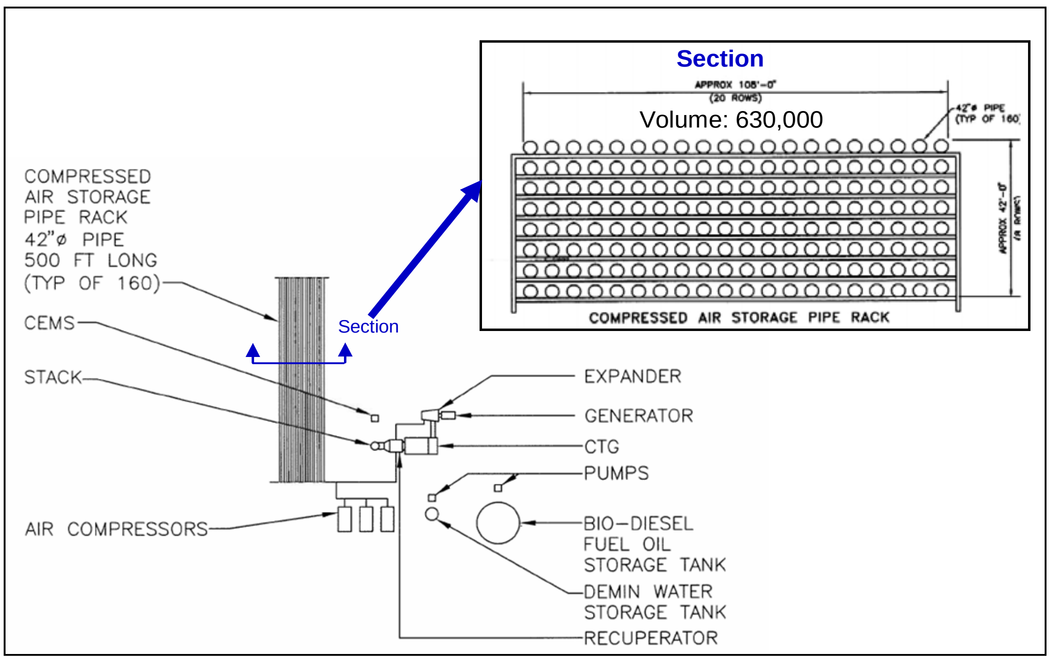
The CAES plant utilizes the same pipe network required for aboveground compressed air storage, but it also includes the following major components:

- An above-ground compressed air storage system sized for 5 hours of expansion turbine operation.
- Enough lineal feet of nominal 42-inch API 5L Grade X60 steel pipe with a nominal wall thickness of 0.875 inches enabling the plant to produce 40 MW's (or 70 MW's) of electricity for 5 hours.
- Steel pipe sloped with drains at regular intervals to eliminate any condensate accidentally introduced into the air storage system.
- Interior and exterior coatings selected with careful consideration for environmentally favorable conditions and compressed air corrosion potential.

- A single reduced port 12-inch Class 600 globe valve with pneumatic piston actuator for controlled release of the compressed air.
- A nominal 16-inch carbon steel interconnecting pipe between the above-ground compressed air storage system and the plants recuperator.

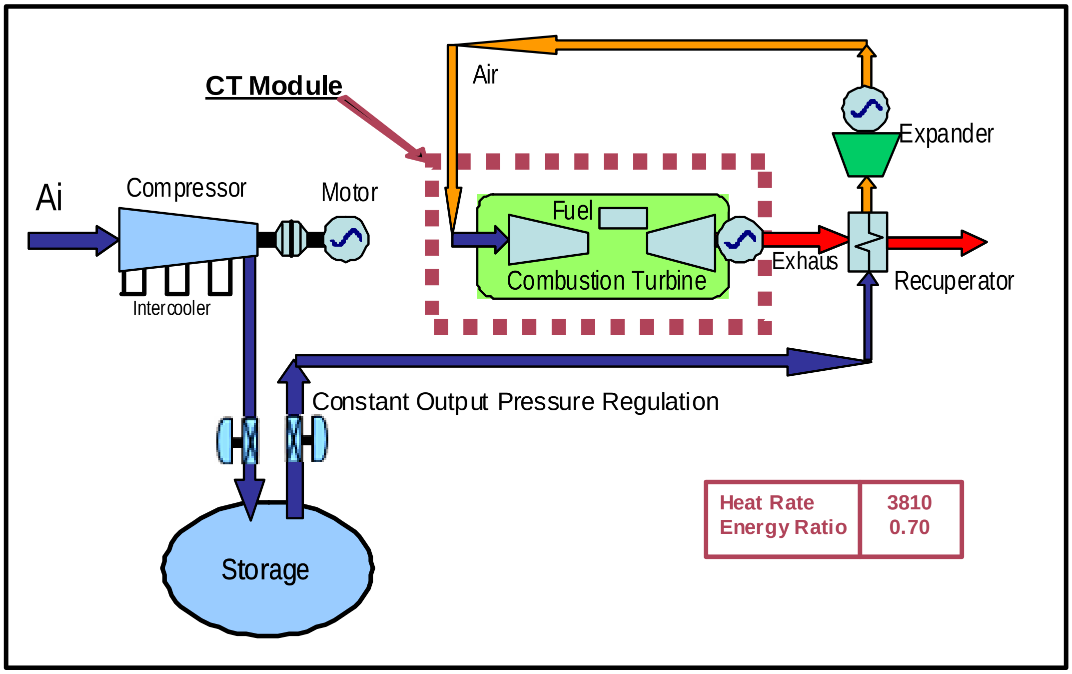
The above-ground air storage system consists of a piping manifold with a storage capacity sufficient to provide 40 MW's (or 70 MW's) for five hours of expansion turbine operation (see Figures 3-6 and 3-7). The piping is installed at a slight incline with drain valves to collect any water produced by air in the air pipeline. Air is released from the above-ground air store during the discharge cycle at a constant pressure. A GE LM2500 aero-derivative combustion turbine expels heated exhaust through the plant recuperator to heat the air coming from the air store.

Figure 3-6: CAES Plant Using an Above-Ground 40 MW or 70 MW- 5 Hour Air Storage System -- Preliminary Plant Layout -- Top View



Source: EPRI

Figure 3-7: Schematic of SCE Advanced CAES Plant Using a 40-MW or 70-MW, 5-Hour Above Ground Air Storage System



Source: EPRI and ESP

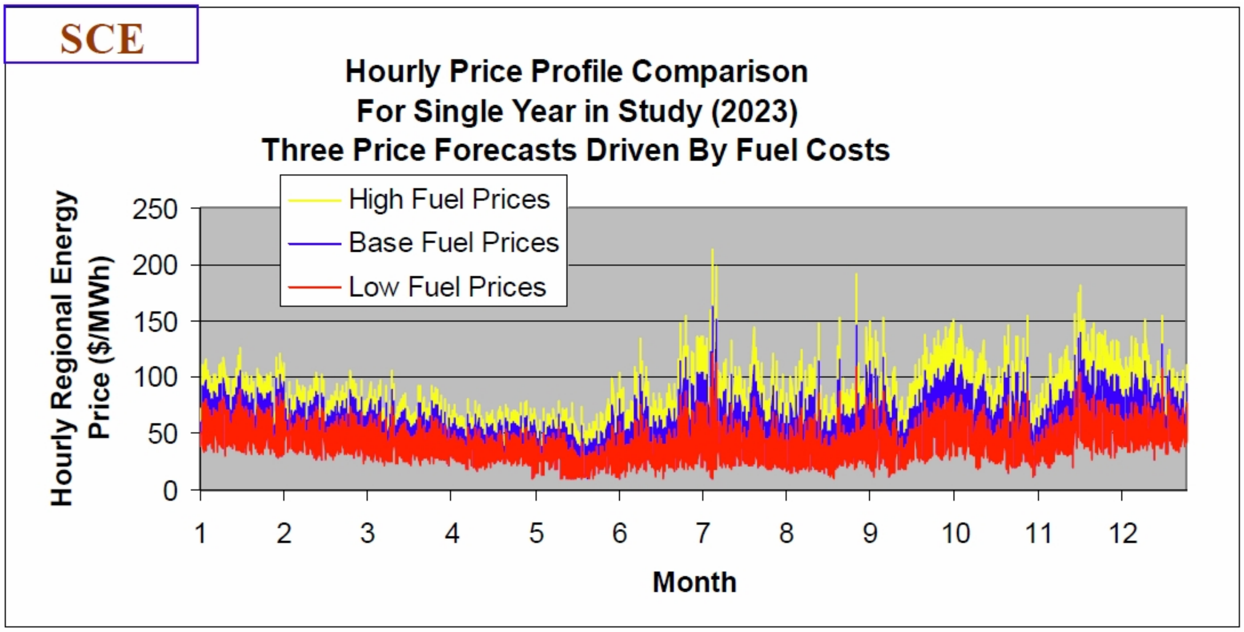
DYNATRAN Economic Analysis of the CAES Plants

EPRI performed a DYNATRAN economic analysis of the two recommended CAES plants with the following specifications:

- 40 MW and 70 MW maximum discharge capacities
- 28 MW and 49 MW capacity compressor systems, respectively (enabling one hour of compression for each hour of generation)
- 5 hours storage capacity (200 MWh and 350 MWh, respectively)
- 4329 Btu/kWh (HHV) heat rate during the discharge generation cycle
- 0.7 MWh energy input per MWh energy output during the discharge cycle
- $3.5/MWh variable O&M

The DYNATRAN simulation assumes a study period of 2012 through 2032. The CAES plants will be dispatched to use relatively low off-peak electricity energy costs to displace on-peak, higher electric energy expenses (for example, for "arbitrage" duty). For the input data specified above and these assumptions, the analysis first determined hourly electricity prices for each of the three natural gas price scenario forecast cases (see Figure 3-8).

Figure 3-8: Hourly Electricity Prices by Scenario for SCE



Source: EPRI

DYNATRAN then calculated the annual hours of storage discharge for energy arbitrage in the three scenarios (see Figure 3-9). This is the number of hours that the CAES plants are generating at a capacity at or above their minimum capacity.

Figure 3-9: Annual Hours of Discharge for Energy Arbitrage for SCE CAES Plants

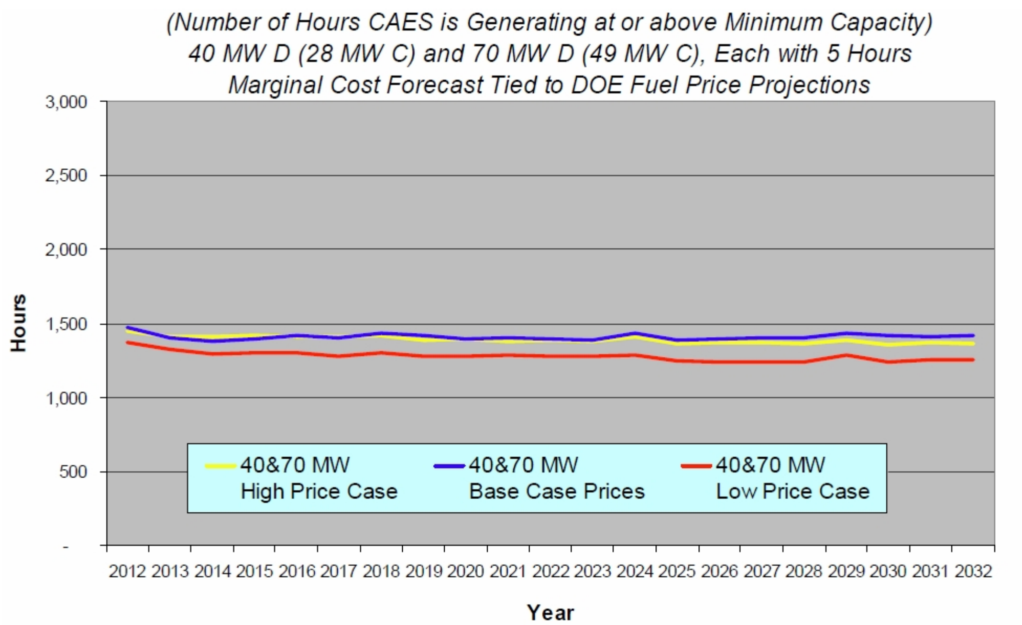


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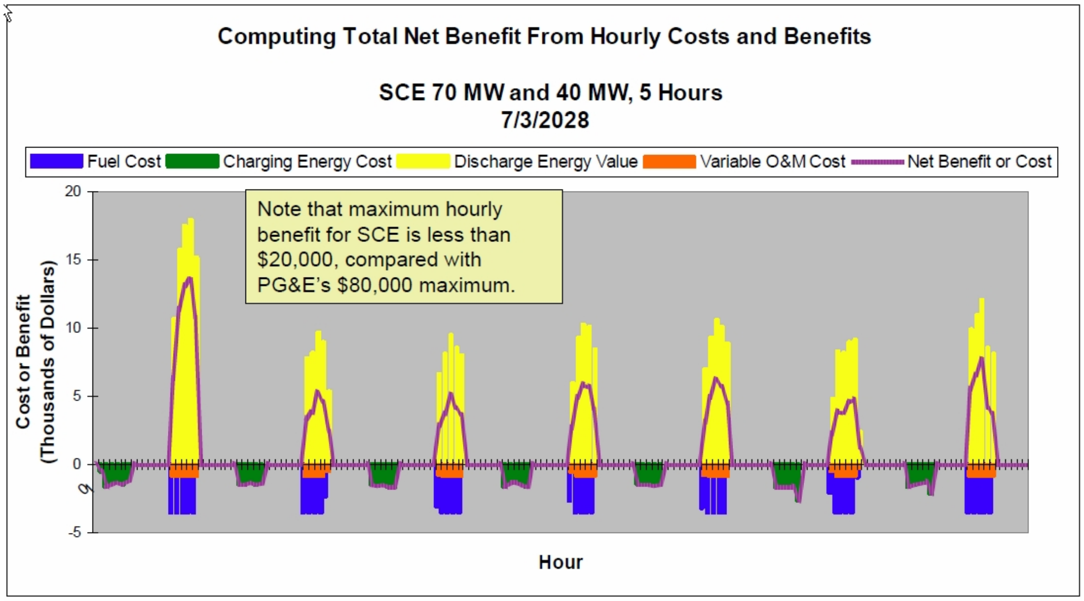
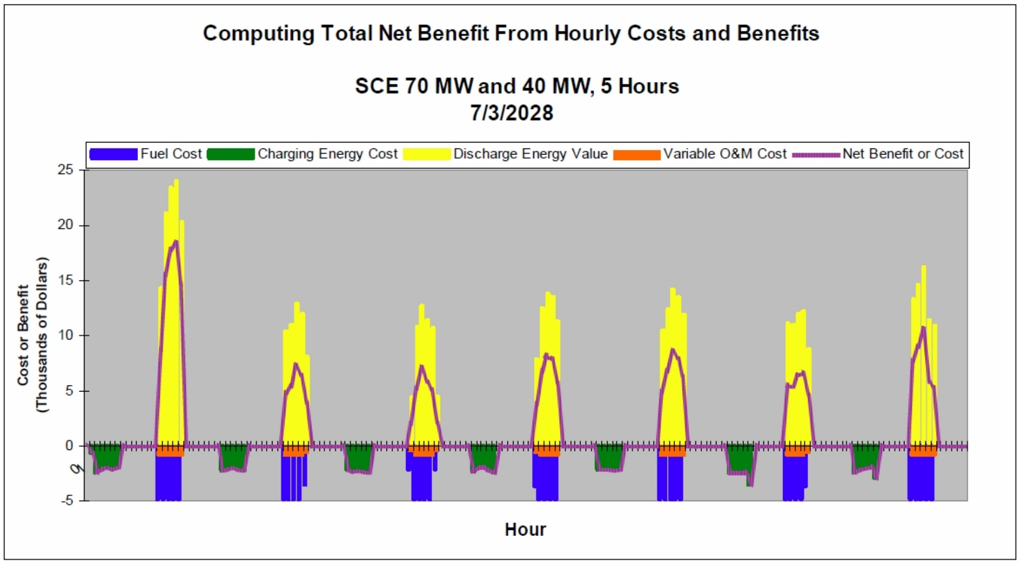
Figure 3-10: Hourly Storage Economics for SCE Base Case Scenario on 7/3/28



Source: EPRI

Figure 3-11: Hourly Storage Economics for SCE High Case Scenario on 7/3/28



Source: EPRI

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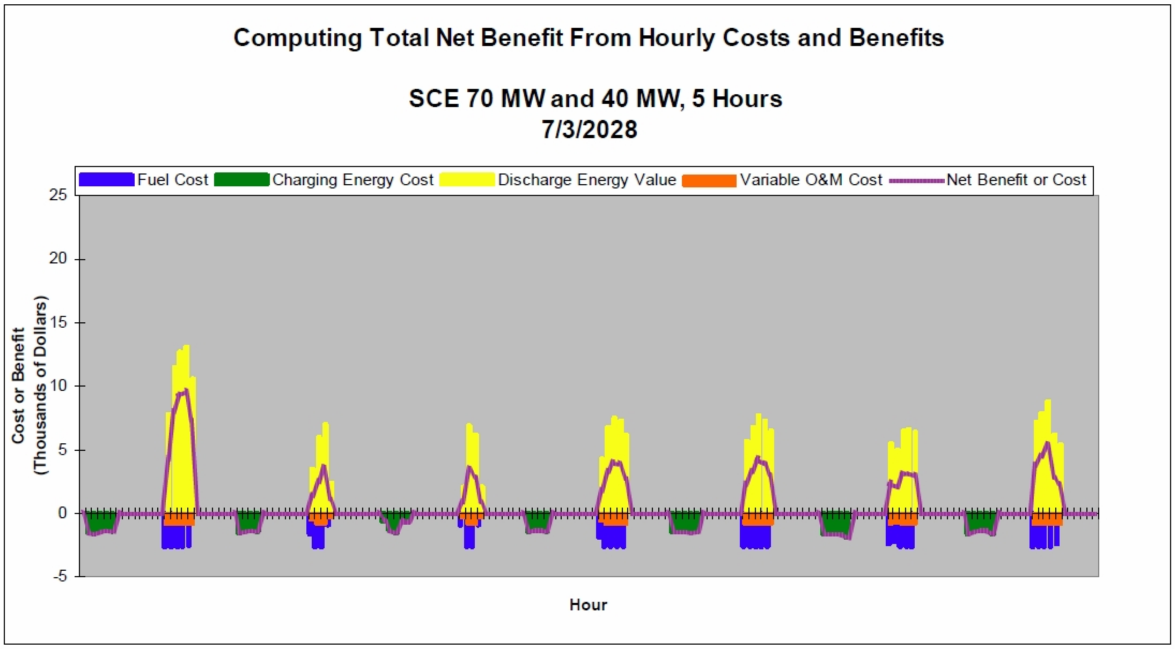
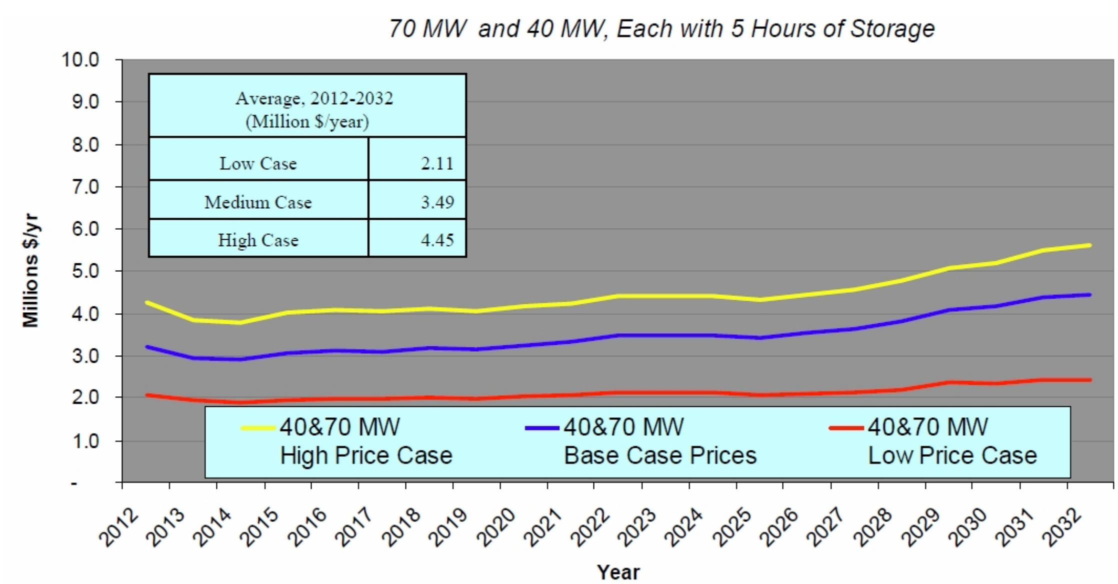


Source: EPRI

Figure 3-13 compares the net annual economic benefit from energy arbitrage under the three fuel price cases. Note that these values do not account for an annual capital cost. They are the net operating benefit. The average annual benefit over the study period is $2.1 million in the low fuel price case, $3.5 million in the base case, and $4.5 million in the high case.

Figure 3-13: Comparison of Net Economic Operating Benefit Under the Three Fuel Price Cases



Source: EPRI

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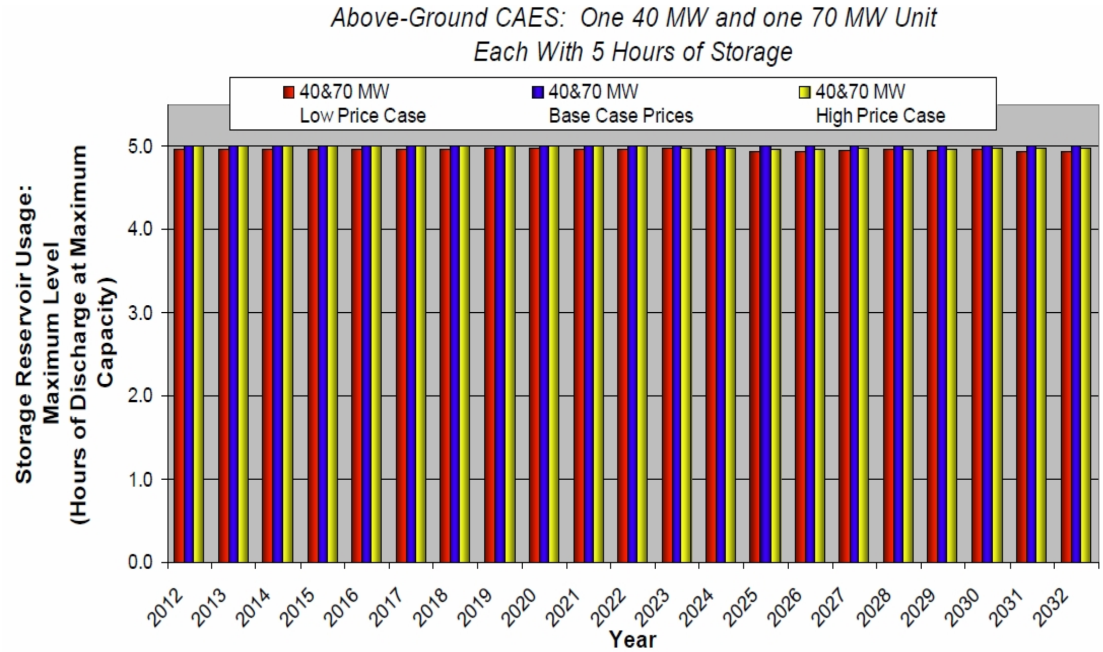

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- **Avoiding Curtailment Payments:** An important application of storage plants is to prevent the curtailment of wind energy. Curtailment costs were not provided; however, an estimate based on wind energy contract prices is made for comparison purposes.

Currently, California has no active market for these services, but the potential exists for CAES storage plants to provide benefits in each of these areas. The project team estimated the value using replacement capacity costs and ancillary services markets elsewhere. For comparison, the overnight cost of a combustion turbine (CT) was assumed at $969/kW (2009) and the CT's fixed O&M cost was assumed at $11.33/kW-year. Further, to incorporate the cost of capital, the analysis assumed a cost of capital reflecting current California utility return-on-equity requirements of 11.5 percent.

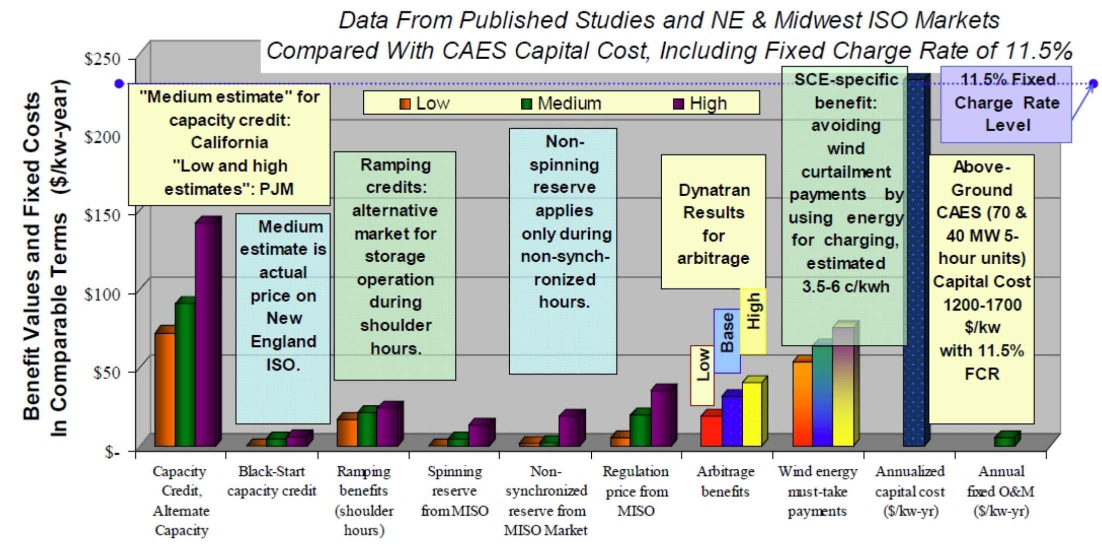
Figure 3-15 compares the benefits from these energy- and capacity-related ancillary services, the arbitrage benefits, and the annualized cost and annual fixed O&M costs. The benefits are shown in $/kW-year for each of the three fuel price cases. This analysis also includes an SCE-specific benefit; avoiding wind curtailment payments by using energy for charging is estimated at 3.5-6.0 cents/kWh.

This shows that benefits from ancillary services can be significantly larger than benefits from arbitrage alone. It also shows that while arbitrage alone may not be sufficient to cover the annualized CAES capital and O&M costs, the inclusion of ancillary benefits can provide a significant net benefit, depending on the fuel price scenario.

It should be noted that the main benefit of the above-ground energy storage systems proposed for SCE is that they would enable the wind farms to never be curtailed due to transmission system constraints. As such, an SCE System Operating Bulletin regarding Antelope Bailey requiring the curtailment of 110 MW of generation (10 MW per wind farm) at peak generation and low local system load to prevent line overloading would not apply. Thus, based on the data available to perform the study herein, SCE would never again have to pay for this energy must-take whether the energy is consumed or not, since the proposed energy storage plants could be used to replace the practice of curtailing wind generation at its 66/230-kV Antelope

Bailey grid system. Since such curtailment costs were not available (and beyond the scope of this work), this benefit, even though large, was not used in the analyses presented herein.

Figure 3-15: Potential Economic Benefits Including Capacity and Ancillary Services Value



Source: EPRI

CHAPTER 4:
Conclusions and Recommendations

PG&E

Conclusions

- The Midway substation was chosen as the candidate site for incorporating bulk energy storage plant on the PG&E transmission system because of its proximity to wind generation at Tehachapi and because its location possesses the unique geology that makes large/bulk scale compressed air energy storage using an underground air store possible. Tehachapi currently has over 750 MW of interconnected wind generation with firm plans to increase wind generation to 4200 MW over the next five years. The increase in Tehachapi's output places it as the premier wind energy location in California. In comparison, the Altamont wind generation site, near the Tesla Substation, generates about 500 MW, and there are no current plans for wind generation expansion.

- Based on the selection criteria, the best energy storage plant for siting at or near Midway Substation is CAES using an underground air store. EPRI and PG&E selected underground CAES technology for this project because it is a proven technology with equipment commercially available from more than one manufacturer. CAES is also expected to require less lead time than pumped storage, has more siting flexibility than pumped storage, and is larger and more cost-effective than batteries and flywheels. CAES is also a good complement to the existing Helms pumped hydro energy storage plant.

- PG&E has identified a specific saline porous rock site near Midway Substation, which meets all the criteria for a suitable CAES underground air storage media – high permeability, good porosity, proven caprock, and a relatively large storage formation volume. This site is ideally located adjacent to PG&E's Midway-Vincent #3 500-kV electric transmission line, which connects Northern and Southern California, and PG&E's gas transmission line 300 A&B. The site is also located less than 60 miles from the Tehachapi Wind Resource Area.

- Analysis using EPRI's proprietary DYNATRAN software metrics tool estimates that the optimum size of the proposed CAES bulk energy storage plant using an underground air store can likely be sited near the Midway Substation and should be sized at an approximate capacity of 300 MW with 10 hours of storage. This analysis factored in the amount of wind generation produced at Tehachapi and the economic value of time shifting off-peak wind energy into on-peak electric demand time periods.

- DYNATRAN analysis results also showed that benefits from ancillary services can be significantly larger than benefits from arbitrage alone. Arbitrage benefits alone may not be sufficient to cover the annualized CAES plant capital and O&M costs, but the inclusion of ancillary benefits can provide a significant overall net benefit exceeding the capital and O&M costs for the plant, depending on the fuel price scenario.

- The CAES technology has the potential to augment renewable generators, meet the on-peak needs of the California grid, minimize environmental impact, and mitigate the power fluctuation and energy management (such as ramping and regulation) issues associated with wind and other renewable generation resources. Also, PG&E believes it is uniquely positioned to host demonstrations of CAES, which will be an important enabler of clean, renewable energy and smart grid capability in California.

Recommendations

EPRI recommends the following next steps:

- Perform more detailed geologic studies of potential underground storage sites for CAES plants in the PG&E territory.
- Select a site based on these subsequent CAES focused geologic analyses.
- For the selected site, review/update forecasted prices for marginal electricity prices and fuel prices; estimate additional benefits from ancillary services provision and other benefits; and conduct economic benefit/cost and business case analyses.
- Determine the plant specifications to match the geological conditions of the selected storage site.
- If this subsequent analysis is favorable, proceed to a construction effort to build a CAES plant.
- Initiate the environmental permitting process at the selected site.

SCE

Conclusions

- SCE's Antelope-Bailey system suffers from most of the issues associated with the intermittences of wind generation. The sites selected for this study, Cal Cement and Goldtown, are considered primary points of interconnection to wind generation in the SCE system. These electric buss substations transmit power along three transmission lines to the Antelope/SCE bulk network system; each is susceptible to overloading, making Cal Cement and Goldtown ideal candidates for one or more energy storage plants.
- The team analyzed empirical data, and drew upon past experience to determine that approximately 5 hours of storage was needed at the Cal Cement and Goldtown substation sites. The project team then used DYNATRAN to determine the levelized costs of various energy storage technologies. This analysis indicated that CAES using a underground air store would be the least-cost solution. However, since a suitable below-

ground reservoir could not be identified in the area, the second lowest cost solution – CAES using an above ground air store – was identified as the least cost, viable solution.

- The project team determined with some certainty that installing two CAES plants for a combined 110 MW of storage capacity, one at Cal Cement and the other at Goldtown, would indeed satisfy the California ISO System Operating Bulletin requirements for reducing overloading on the lines into these substations, and hence, eliminate the need to curtail wind generation to the Antelope Bailey system. In order to reduce the impact on the network system, SCE and EPRI recommends placing a 70-MW, 5-hour storage system at the Cal Cement 66-kV Substation, and 40-MW, 5-hour storage system at the Goldtown 66-kV Substation. The total energy storage capacity is based on the amount of total curtailment under worst case conditions of 10 MW at each of the 11 wind farms in the local network subsystem. This means SCE will lower its energy must-take costs, which translates into savings for the ratepayer.

- DYNATRAN analysis also shows that benefits from ancillary services can be significantly larger than benefits from arbitrage alone. It also shows that while arbitrage alone may not be sufficient to cover the annualized CAES plant capital and O&M costs, the inclusion of ancillary benefits can provide a significant net benefit, depending on the fuel price scenario assumed.

- It should be noted that the main benefit of the above-ground energy storage systems proposed for SCE is that they would enable the wind farms to never be curtailed due to transmission system constraints. As such, an SCE System Operating Bulletin regarding Antelope Bailey requiring the curtailment of 110 MW of generation (10 MW per wind farm) at peak generation and low local system load to prevent line overloading would not apply. Thus, based on the data available to perform the study herein, SCE would never again have to pay for this *energy must-take* whether the energy is consumed or not, since the proposed energy storage plants could be used to replace the practice of curtailing wind generation at its 66/230-kV Antelope Bailey grid system. Since such curtailment costs were not available (and beyond the scope of this work), this benefit, even though large, was not used in the analyses presented herein.

- As a result of this study, SCE is giving serious consideration to installing CAES at these two critical interconnection points to its Antelope-Bailey network subsystem to eliminate the need for curtailment at 10 area wind farms and to reduce transmission line overloading.

Recommendations

EPRI recommends the following next steps:

- Perform detailed studies of potential sites for CAES plants based on above ground air stores.

- Select a site based on these analyses.

- For the selected site, review/update forecasted prices for marginal electricity costs and fuel costs; estimate additional benefits from ancillary services provision and other benefits; and conduct an economic benefit/cost and business case analyses.
- Determine the plant specifications for the selected storage site(s).
- If this subsequent analysis is favorable, proceed to a construction effort to build CAES plant(s) that utilize above ground air stores.
- Initiate the environmental permitting process at the selected site(s).

Overall

Conclusions

EPRI, PG&E, SCE, and the remainder of the project team achieved all of the objectives for this project; namely:

- Instead of identifying two priority locations in California to deploy electric energy storage plants to mitigate wind generation transmission and operational issues, the project team identified three such site locations.
- The team defined and quantified the following technology performance metrics associated with successfully integrating energy storage with grid locations impacted by wind generators:
    - Minimum capacity
    - Minimum number of hours of energy absorption and delivery to time-shift significant amounts of wind generated energy
    - Minimum response time to full output to provide ramping, load following, and regulation services to the California grid
    - Ability to complement other existing technologies such as pumped hydro storage plants
    - Siting flexibility
    - Use of proven technology with commercial components that are readily available
    - Capacity for future expansion or increased performance
    - Minimum cost
- The project team developed and documented equipment specifications, which are summarized above, to satisfy site requirements for each substation site investigated.
- The project team developed and implemented a metrics-based tool that can determine the value of siting an energy storage plant at the selected sites, and at other substation sites in California. This study further validated the use of this tool in this application.

CHAPTER 5: Acronyms and Glossary of Terms

Acronyms

$/kW	Dollars per kilowatt
AEC	Alabama Electric Cooperative (now called PowerSouth Energy Cooperative)
Btu	British thermal unit, heat needed to raise one pound of water, one degree Fahrenheit at sea level, from 59F to 60F
CAES	Compressed air energy storage
CAIDI	Customer average interruption duration index
CAIFI	Customer average interruption frequency index
California ISO	California Independent System Operator
CC	Combined cycle
CO_2	Carbon dioxide
CT	Combustion turbine
DOE	U.S. Department of Energy
ESP	Energy Storage and Power LLC, a subsidiary of Public Service Electric and Gas
EPRI	Electric Power Research Institute
kW	Kilowatt
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
O&M	Operation and maintenance
PG&E	Pacific Gas and Electric
PIER	Public Interest Energy Research
R&D	Research and development
RPS	Renewable performance standards
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCE	Southern California Edison
SMES	Superconducting magnetic energy storage
VAR	Voltage-ampere reactive

Glossary of Terms

Compressed Air Energy Storage (CAES): CAES plants use low-cost off-peak electricity to compress air into an underground reservoir, surface vessel, or a piping air storage system. When electricity is needed, the pre-compressed air is withdrawn from the storage reservoir and combined with fuel in a combustion process to generate electricity. Because the air is already compressed, the daytime electricity generation is much more efficient, and emits much less CO_2 and pollutants than traditional power generation processes. Because the wind blows at night, nighttime wind power can be used to charge the air storage reservoir, enabling this renewable resource to provide on-peak power during the day. Also, because renewable resources are intermittent, a CAES plant can act as a "shock absorber" to smooth out wind and solar power fluctuations, eliminating many of the operational complexities that this intermittency brings.

Renewable Portfolio Standards (RPS): RPS regulations are enacted, or in the process of being enacted, in most states in the U.S. Although they vary from state to state, most specify that the utilities that operate in their state must demonstrate that a specified percentage of the electric power that they generate must be derived from renewable resources by a specified date. Various states define "renewable resources" in different ways. As currently planned, California's RPS will specify that 33 percent of electricity generated in California must be derived from renewable resources by the year 2020. Currently the California RPS states that 20 percent of the electricity generated in California must be derived from renewable resources by the year 2010.

Voltage-Ampere Reactive (VAR): VARs are used to measure reactive power in the power system. A sufficient amount of VARs are needed to effectively operate the power system. Voltage/VAR control is used to control the production, adsorption, and flow of reactive power in the power system. Traditional sources of reactive power include generators, shunt reactors, and shunt capacitors. Relatively new sources include various power electronics devices such as reactive power controllers and static VAR compensators. Advanced CAES plants like the ones suggested for SCE and PG&E can add or subtract VARs to the system as required – a capability that has been proven in both the Alabama and Germany CAES plants.

APPENDIX A: Technology Transfer Plan to Disseminate Project Results

Introduction

One of the tasks of this project is to provide a Technology Transfer Plan. The goal of this plan is to disseminate the knowledge gained, results achieved, and lessons learned in this project to various key decision makers. These decision makers include executives and managers at utilities; federal and state regulators; associations; federal, state, and local government agencies; research and development entities; equipment vendors; the public, and others. This appendix summaries the project team's Technology Transfer Plan.

Motivation for the Plan

This study contains important insights with potentially significant impacts on the electric power industry, as well as its shareholders and ratepayers. However, for the information in this report to become relevant to these stakeholders, it must be effectively communicated. Compressed air energy storage (CAES) presents a significant opportunity to enable accelerated adoption of renewable energy resources in California and elsewhere – a topic that is on the minds of politicians, regulators, utility executives, industry insiders, as well as consumers. Renewable energy resources are an important part of an overall strategy to reduce carbon emissions. Hence, this technology transfer plan has broad ramifications beyond the confines of this single project.

Elements of the Plan

EPRI and the remainder of the project team are committed to the effective communication of project results by informing various parties in various ways and bringing stakeholders to the table to discuss the relevant technology and opportunities. (Note: All information gathered and insights gained in this project are in the public domain.) To this end, the Technology Transfer Plan lays out an approach to communicate results and insights in the following different ways:

- Published documents
- Interactive online events
- In-person presentations

Published Documents

EPRI and the project team plan to publish various documents, in addition to this project report, and submit them for publication in various venues. These include the following:

- EPRI will publish this project report as an EPRI technical report and make it available at no fee to any interested parties on its web site (www.epri.com).

- EPRI will submit a conference paper/presentation at an upcoming Electricity Storage Association (ESA) conference (www.electricitystorage.org). ESA is a trade association that fosters development and commercialization of energy storage technologies. Its members include electric utilities, independent power producers, energy service companies, technology developers, and researchers. Hence, this published paper will reach a cross-section of interested parties.
- EPRI will submit a conference paper/presentation at an upcoming conference of the Electrical Energy Storage Applications and Technologies (EESAT). EESAT is organized by the U.S. Department of Energy, Sandia National Laboratories, and ESA.
- EPRI will talk with various wind power experts to identify a wind power conference at which to publish/present a paper summarizing the objective and results of this study. Due to high degree of relevance of this project's results to the wind power industry, presenting a paper at a wind power conference will help to engage stakeholders in that important and growing portion of the electric power industry.

Interactive Online Events

EPRI and the project team plan to conduct various interactive online events to disseminate the results and findings of this study to various stakeholders. These include the following:

- EPRI will conduct an interactive webcast to all interested parties on this project. This webcast will cover the motivation for the project, the project objectives, the project approach, project results, and the implications of these results. The webcast will allow time for attendees to ask questions about the project.

In-Person Presentations

EPRI and the project team plan to give presentations to various groups of stakeholders in-person to disseminate project results. These include the following:

- EPRI will present the project results to representatives of the California Energy Commission and U.S. DOE as appropriate.
- EPRI will present the project results to its EPRI Energy Storage Advisory Committee. This group consists of directors and managers at a large number of utilities across the country, including California, which fund EPRI research on electric energy storage.

Plan Schedule

EPRI plans to conduct these technology transfer activities according to the schedule shown in Table A-1.

Table A-1: Schedule for Technology Transfer Activities

Technology Transfer Activity	Approximate Date
Publish the present EPRI technical report	January 2011
Submit a paper and present at 2011 ESA conference	May, 2011
Submit a paper and present at next EESAT conference	October 2011
Submit a paper and present at an upcoming wind power conference	2011
Conduct interactive webcast	January 2011
Present results to CALIFORNIA ENERGY COMMISSION and U.S. DOE	2011
Present a summary of the project results to EPRI's Energy Storage Advisory Committee composed of a wide set of U.S. electric utility companies	September 2010 (Completed)
Present a summary of the project results to the utility members of the EPRI Board of Director Initiated Advanced CAES Demonstration Project	September 2010 (Completed)

EPRI and the project team believe that this set of technology transfer activities will effectively convey the findings, implications and insights gained from this study to a broad range of stakeholders.

APPENDIX B:
Technology Readiness Plan for Metric Tool

Objective

The goal of this task is to develop a technology readiness plan for assessing potential pathways to deployment of energy storage technologies to mitigate the effects of wind energy on the grid.

Required Elements of the Plan

The technology readiness plan should contain the following:

- Task 1: Identification of the logic and/or software needed to commercialize the metrics-based tool used in this project so that others can perform this work on their own
- Task 2: A commercialization plan and cost estimate to develop a commercial version of the metrics-based software tool
- Task 3: A list of potential commercializer companies that can supply this type of software
- Task 4: Time interval expected to develop the software and commercialize it
- Task 5: A time-phased implementation plan to perform the work needed to commercialize the metrics-based software tool.

Task 1: Identification of Software Needs

Summary

The software needed to commercialize the metrics-based tool used in this project is the EPRI DYNATRAN software code. DYNATRAN is a unique EPRI production-costing and network simulation system with a primary focus on evaluating energy storage plants on electric utility systems. The program offers two primary options to perform analyses. Where the key focus is energy storage plant operation as a function of marginal costs or market prices in an ISO environment, the program can be directed to proceed directly to analyzing an energy storage plant's operation, given hourly electricity marginal cost prices and fuel prices (if a CAES or other fuel using energy storage plant is under consideration). Where more detailed utility system operation is the objective of the analysis, DYNATRAN can use traditional production-costing inputs (including thermal load, generating plants, purchases and sale contracts) to produce an economic dispatch that not only incorporates energy storage plants but also reports on the net dynamic operating benefits within the generation system under consideration. In that system-operations mode, DYNATRAN can also be used to assess electric power flows over each transmission line within an interconnected network with transmission constraints.

The current version of DYNATRAN includes the following key technical features:

- Energy-market dispatch, with:
    - Spinning and ready reserves
    - Ancillary services markets
- System dispatch modeling with:
    - Monte Carlo simulation of generation forced outages
    - Emission modeling and combined cost and emission dispatch
    - Maximum fuel limits and secondary fuels
- Transmission network modeling with:
    - Area commitment constraints
    - Modified AC load flow and single contingency criteria
    - Control of Flexible AC Transmission Systems (FACTS) for line overloads and voltage violations
    - Generation rescheduling to reduce line overloads

In this study, only the energy-market dispatch capabilities of DYNATRAN were used.

Energy Storage Arbitrage Dispatch

DYNATRAN is designed to simulate a least-cost dispatch for energy storage technologies. Each potential storage system offers specific opportunities and constraints. For example, traditional pumped-hydro facilities are characterized with large energy storage capacities (in MW and MWh). Some pumped hydro operations include a seasonal component. DYNATRAN can be instructed to build stored energy from week to week during a fill season and to lower net stored energy during an overall discharge season. Battery storage, which is most appropriate for smaller-scale applications with short-term charge-discharge cycles, has no fuel requirement, but generally has tight constraints on available stored energy. Compressed Air Energy Storage (CAES) may be designed for either small-scale (such as, for 10 MW-2 hour plants) or large-scale applications (for example,, for 300 MW-10 hour plants). Most CAES plant designs call for some fuel (such as, natural gas) consumption during the discharge stage of the cycle, so the plant's electric energy output per plant electric energy input is greater than one. DYNATRAN is also appropriate for analyzing newly developing energy storage technologies, such as Superconducting Magnetic Energy Storage (SMES), which has potential for highly efficient energy storage operations. In addition, DYNATRAN's storage algorithm can be used to model special dispatch procedures for thermal or traditional hydroelectric plants, or energy contracts that have operating effects resembling storage.

The storage algorithm seeks to minimize overall production costs by shifting energy from off-peak periods (when costs are low) to on-peak periods (when system costs are otherwise high). This process is variously termed "energy arbitrage," "load leveling," or "cost minimization," but the algorithm is the same regardless of the name applied. The energy storage analysis proceeds only once the necessary cost signals have been obtained (whether from a system dispatch or from market information). At this point, the model has access to an hourly price profile for a week, typically beginning with midnight on Sunday and continuing through the weekdays and on to the weekend days.

Characterizing the Energy Storage Facility

An energy storage plant is characterized by size (MW and MWh), efficiency (kWh-out/kWh-in), heat rate (such as, for a CAES plant), maintenance costs, and specific dispatch constraints. Unlike a traditional generating plant, an energy storage plant has two generation capacity values: the MW capacity during the time the plant is in the generation mode (the output or discharge MW capacity) and the MW capacity during the time period the plant is in the charge mode (the input or charge MW capacity). Both capacity values can be different and are specified by the user.

An energy storage plant also has a third type of "capacity" – the energy storage capability or storage "volume" expressed in hours of discharge at maximum power when the plant is fully charged, or expressed in MWh capability with the plant is fully charged. For pumped hydro, the storage volume represents an actual physical volume of water that is moved between the upper and lower reservoirs. For CAES, the volume is linked to the volume of air stored in the air storage system (such as, an underground aquifer, depleted gas field, salt cavern, or pressurized piping air store). However, the actual physical volume is a function of the specific design, including the pressure at which the air is stored and the pressure of the air when it is used during the plants generation cycle. For batteries or SMES, the "volume" is a conceptual link to the chemical or magnetic energy storage capability, respectively. In each case, the storage volume is specified in terms of the number of hours the storage plant can be operating at its maximum discharge capacity starting at a "full" state in the storage reservoir and ending at the minimum stored-energy state appropriate to the energy storage plant under consideration. This yields a maximum storage capability expressed in MWh.

The energy storage plant under consideration is further defined by its electric energy ratio: MWh of electricity energy output per MWh of electric energy input. For an energy storage plant that does not require additional energy input during the discharge time period (such as, pumped hydro, battery or flywheel energy storage plants), the energy ratio is less than 1.0, representing an output-input plant efficiency number. For energy storage plants that do use energy (such as, from fuel) during the plants discharge cycle (such as, CAES plants), the energy ratio is typically greater than 1.0, since additional energy is required in the form of fuel (such as, natural gas) during the plants discharge time period. Assigning an "overall efficiency" to energy storage can become complicated when attempting to combine the electric energy input at the time of charging with the fuel energy input at the time of discharging. Any energy storage plant also incurs variable operating and maintenance costs, which are typically applied at the time of discharging.

Reserve operational duty is a particular benefit of most energy storage plants. If the plant is eligible to provide spinning or quick-start reserve, DYNATRAN includes energy storage in the reserve calculations (including backing off thermal generation as economic, when the energy storage plant under consideration can provide the reserve at lower cost). Some energy storage plants are particularly well-suited to providing reserves (spinning/synchronous reserve and non-spinning/non-synchronous reserve). For example, a CAES plant in full charging mode can provide spinning reserve of its full charge capacity (because it can be backed down from charging as quickly as needed) *plus* its full discharge capacity (because it can be turned over to its discharge mode just as quickly). In addition, if the energy storage plant can support frequency regulation, it is given credit for that service, as well, based on price benefit levels for frequency regulation as compared to other duty cycles (such as, arbitrage, spinning reserve, and ramping price benefit levels).

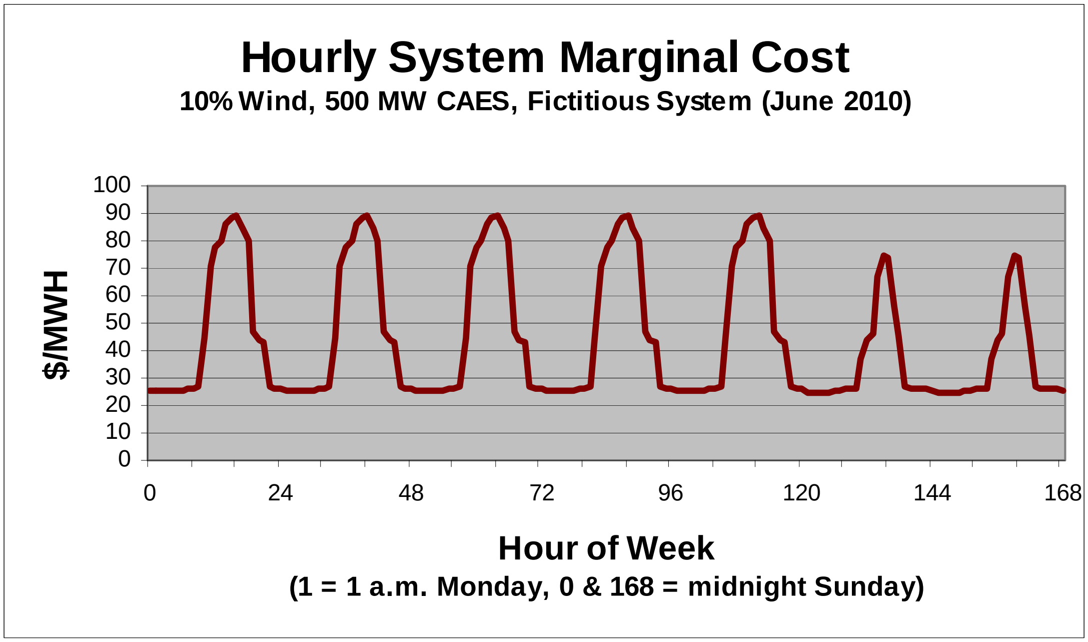
DYNATRAN can take into account several typical dispatch constraints of energy storage plants. If there are ramping constraints, these are respected. If the energy storage plant is scheduled to be off-line, the energy storage plant's operation is curtailed during that time. If the energy storage plant is operating on a seasonal basis, so the energy stored needs to gradually rise or fall over several weeks, DYNATRAN can be directed to add or subtract a specified quantity to the reservoir in addition to the economic scheduling of the energy storage plant in each week. In addition, if there are multiple energy storage plants under consideration, DYNATRAN can be directed to dispatch each of them in a specified order, or let the DYNATRAN program determine the order of dispatch based on each plants economic benefits.

Storage Dispatch Process

DYNATRAN's storage dispatch process begins with an hourly chronological system cost curve for a full week. (Usually, this is a specific week in a year. However, it is also possible to model a system with "typical" weekly data for a month or a season.) Figure B-1 shows a sample marginal cost curve for a generic utility system. The sample follows a typical summer load pattern of weekday peaks with lower peaks on weekend days.

DYNATRAN's storage dispatch process begins with an hourly chronological system cost curve for a full week. (Usually, this is a specific week in a year. However, it is also possible to model a system with "typical" weekly data for a month or a season.) Figure B-1 shows a sample marginal cost curve for a generic utility system. The sample follows a typical summer load pattern of weekday peaks with lower peaks on weekend days.

Figure B-1: Sample of Hourly System Marginal Cost
(Derived From Either Thermal Dispatch or Market Prices)



Source: EPRI

In the sample case shown in Figure B-1, most off-peak hours (about half the hours in the week) have system costs less than about $40/MWh. On-peak costs range from $50-90/MWh. Even with natural gas consumption for CAES, this price margin is more than sufficient to make storage operation economically attractive.

DYNATRAN implements its cost-minimizing algorithm in four distinct stages.

The first step provides insight to the potential utility of a large storage reservoir, while providing a starting point for the next stage in the process. This unlimited volume dispatch identifies prices for pairs of off-peak to on-peak prices for which a storage plant is attractive, in descending order for the plant under consideration, and for which the starting volume equals the weekly ending volume (or produces a volume change specified by the user). Even for systems with limited storage, it is often useful to produce outputs with the maximum storage volume constraint lifted. In that case, the result is the unlimited-volume charge/discharge cycle, which may reveal that a larger energy storage plant capability is beneficial to the system. Note that this simulation does not simply assign a single "charging price" and a single "discharging price" for the week, but seeks optimal use of energy available in each low-price period and electric energy that can be displaced in each high-price period. The only constraint ignored at this stage is the user-specified maximum storage volume.

The unlimited-volume dispatch provides a starting point for the further optimization of the storage plant operation within its constrained storage volume. This is an iterative process that converges to the most cost-effective dispatch that keeps the range of stored energy within the limits set by the inputs to DYNATRAN. A secondary optimization stage is also run to refine the chronological hourly storage operation to capture any economic and feasible storage opportunities that may have been temporarily set aside during the convergence process (such as, for ramping, frequency regulation).

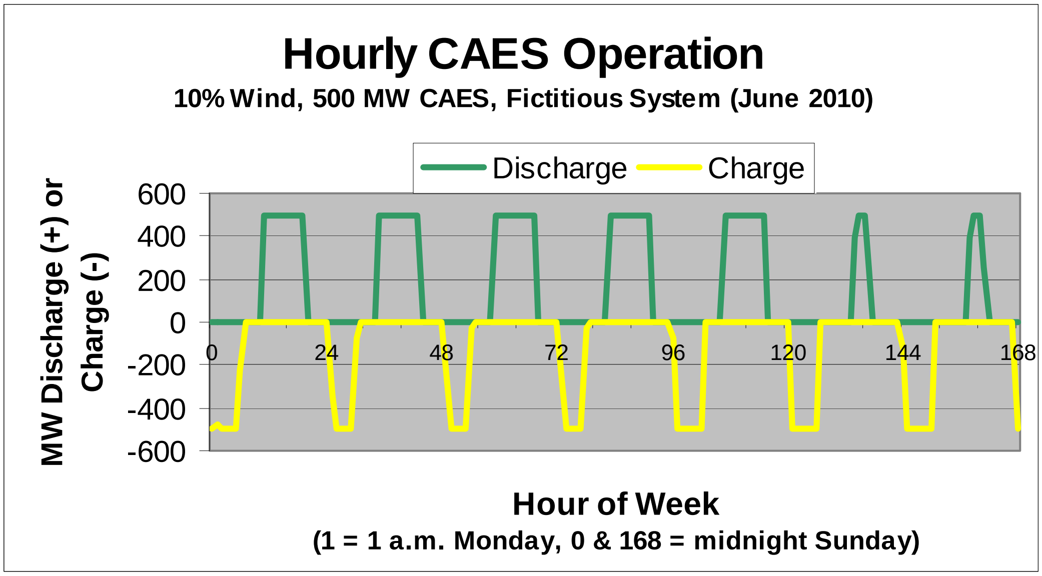
Once the ideal storage operation schedule is determined, checks on constraints are conducted to verify that storage ramp rates, minimum downtime, or maximum uptime limitations are satisfied. If not, the schedule is adjusted accordingly. Note: These constraints are rarely a problem with most energy storage plants.

In the course of the optimization process, DYNATRAN attends to the range of stored-energy volumes, rather than an actual reservoir value. This allows the start-of-week volume level to be any value and for the minimum volume level to fall in any hour. As a final step, once the chronological schedule is optimized to keep the volume within the desired max-to-min range, the hourly stored volume level is adjusted so that the minimum is at zero and the maximum value is either equal to the energy storage constraint or equals the maximum range. The start and end volumes match and are at an appropriate level, depending on prices. Typically, if the starting hour is 1 a.m. on Monday, the storage reservoir is near its maximum level, but this is a result of the analysis, not an input.

In the sample case shown in Figure B-2, a CAES plant charges for a few hours early Monday morning, then begins a daily storage cycle. Figure B-2 shows the hourly charging and discharging; Figure B-3 shows the hourly stored energy in the reservoir. By the end of the peak period on Friday, the reservoir is empty. For the sample case shown, each weeknight, about

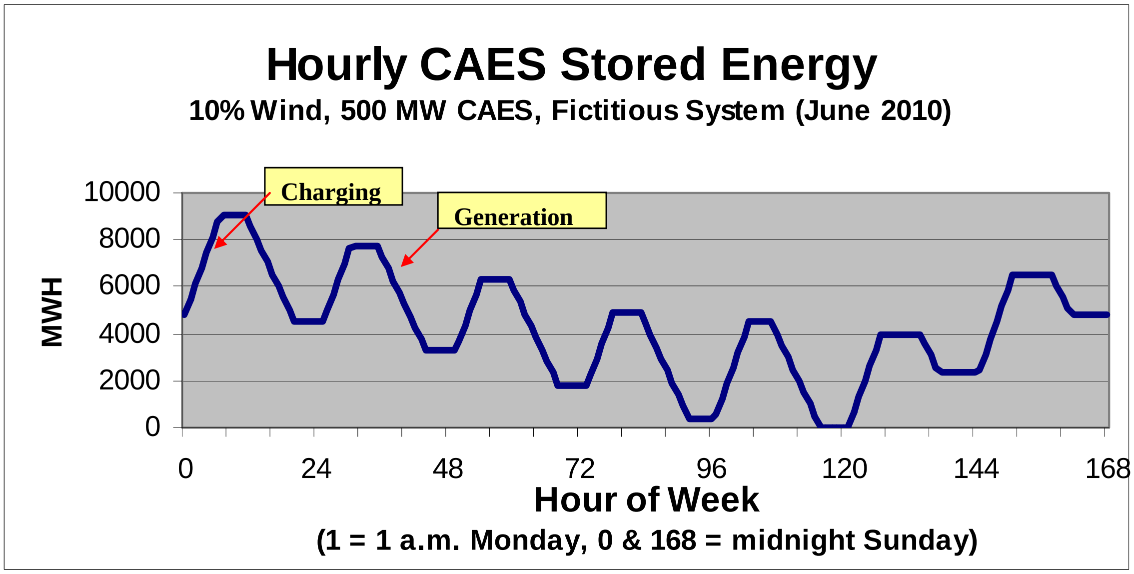
1500 MWh of energy is charging, but on weekend evenings about 2000 MWh of energy is charging. Similarly, the weekday peaks draw down the reservoir by roughly 2000 MWh per day, while weekend discharge periods draw only around 700 MWh each day.

Figure B-2: Sample of Hourly Storage Charge and Discharge Results



Source: EPRI

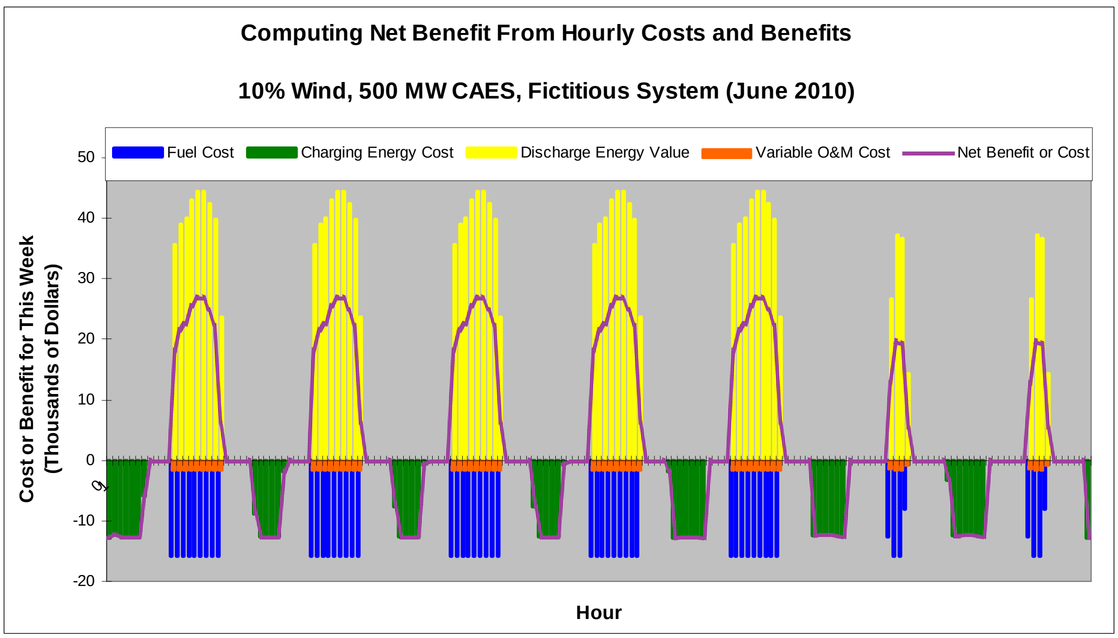
Figure B-3: Sample of Hourly Stored Energy Results



Source: EPRI

Of course, the key to the storage results is the economic benefits. In any given week, storage operates to the extent that it produces net operating savings. This analysis is based solely on operating costs. Note: comparing net annual operating benefits with fixed costs (particularly capital costs) is a separate issue. Figure B-4 shows the hourly pattern of costs and benefits accruing to this sample energy storage plant's operation. In any discharge hour, a typical CAES plant consumes natural gas, the cost of which appears as the blue expense bars in Figure B-4. At the same time, a modest cost attributable to variable operating and maintenance costs is also incurred – the orange expense bars paired with each of the fuel-cost expenses. However, in the discharge hours, CAES displaces expensive on-peak electric energy, and that is an hourly benefit credited to storage – the yellow benefit bars in each generating hour. Finally, in off-peak hours, a cost is incurred for either operating thermal plants or for purchasing off-peak market electric energy, which appears in Figure B-4 as the green expense bars in off-peak hours. The hourly net benefit can be traced as the purple line running hour to hour through this particular sample week. For this example, the total for the week is nearly $600,000 in net savings: on-peak savings less fuel cost, variable O&M cost, and charging cost.

Figure B-4: Sample of Hourly Economic Analysis



Source: EPRI

Storage Dispatch in a Market Environment

Most utilities in the U.S. today operate at least partially in a market environment. Hourly incremental system costs are less tightly linked to an individual company's generating mix and more tied to market prices, operating costs in neighboring territories, or the price impacts of must-take contracts with renewable energy producers. DYNATRAN offers the option to analyze an energy storage plant's operation in just such an environment.

Energy Markets and Storage

Whether the analysis is market-based, a single-area economic dispatch, or a multi-area network dispatch, storage dispatch is chronological and driven by hourly costs. As the electricity network evolves over time, more and more generation is produced and distributed in a market environment. Energy markets incorporate bidding procedures and usually distinguish between spot-market prices and day-ahead bids to provide electric energy. DYNATRAN can accept a set of hourly prices, whether the source is a spot-market or records of closing prices in an active market.

To apply the energy-market dispatch, the DYNATRAN user needs to specify the hourly price profile, hourly system loads coordinated with those prices, fuel prices (if modeling a fuel-using storage plant like CAES), and storage plant characteristics. There is no need to describe other generating plants or to conduct a system dispatch apart from the energy storage plant analysis. The user-input prices yield each week's hourly price profile as in the example shown in Figure B-1.

Capacity, Ancillary Services, and Storage

Once a market-based energy entity, such as an ISO, is in place, markets tend to evolve beyond the basic market for electric energy. First, except in systems with an oversupply of on-peak thermal capacity, there will be some value to providing reliable capacity, whether that provider is an independent generator or an energy storage plant. Second, system operations require more than a simple flow of electric energy. It is important to maintain reserves, both on-line (fully synchronized) and off-line (able to synchronize within a short time frame, typically ten minutes or less). Electric power consumers expect power to be delivered at a consistent voltage and frequency, which can be disrupted in the event of outages or during other shifts in power production. Generation plants or energy storage plants that can allot capacity to provide frequency regulation – and respond quickly enough to be useful in that role – provide additional valued services to the system. In many market systems, new markets are evolving to attract providers of such services. These are termed ancillary services, but the term should not be construed to mean secondary or unimportant services since such services are often of higher economic value than arbitrage services when evaluating energy storage plants.

When an energy storage plant is suited to a particular market, it is likely to operate reliably in on-peak hours, because those are the high-value energy markets when an energy storage plant discharge earns the most for the energy storage plants owner/operator. In that case, the energy storage plant also provides reliable capacity to that market/grid system. This is analogous to traditional long-term system planning, in which an individual utility weighs the operating merits of various types of generating capacity when evaluating which plants to build into a long-term generation/storage capacity plan. A good proxy for the capacity benefit provided by an energy storage plant is the cost of the least-expensive alternative capacity, which is typically a combustion-turbine unit.

Ancillary services are also likely candidates for useful benefits that an energy storage plant can provide. Some of these benefits may accrue in addition to the benefits of the electric energy arbitrage market. Others may compete with arbitrage benefits for directing the scheduling of an energy storage plant's operation.

Operating reserve is one class of benefit that typically can be provided simultaneously with energy market operation. An energy storage plant provides synchronous (spinning) reserve at any time it is in charging mode and whenever it is discharging mode when it is at less than its maximum capacity. Most storage technologies satisfy requirements for quick-start or ready reserve. Some (particularly CAES) units ramp quickly enough to serve as black-start capacity.

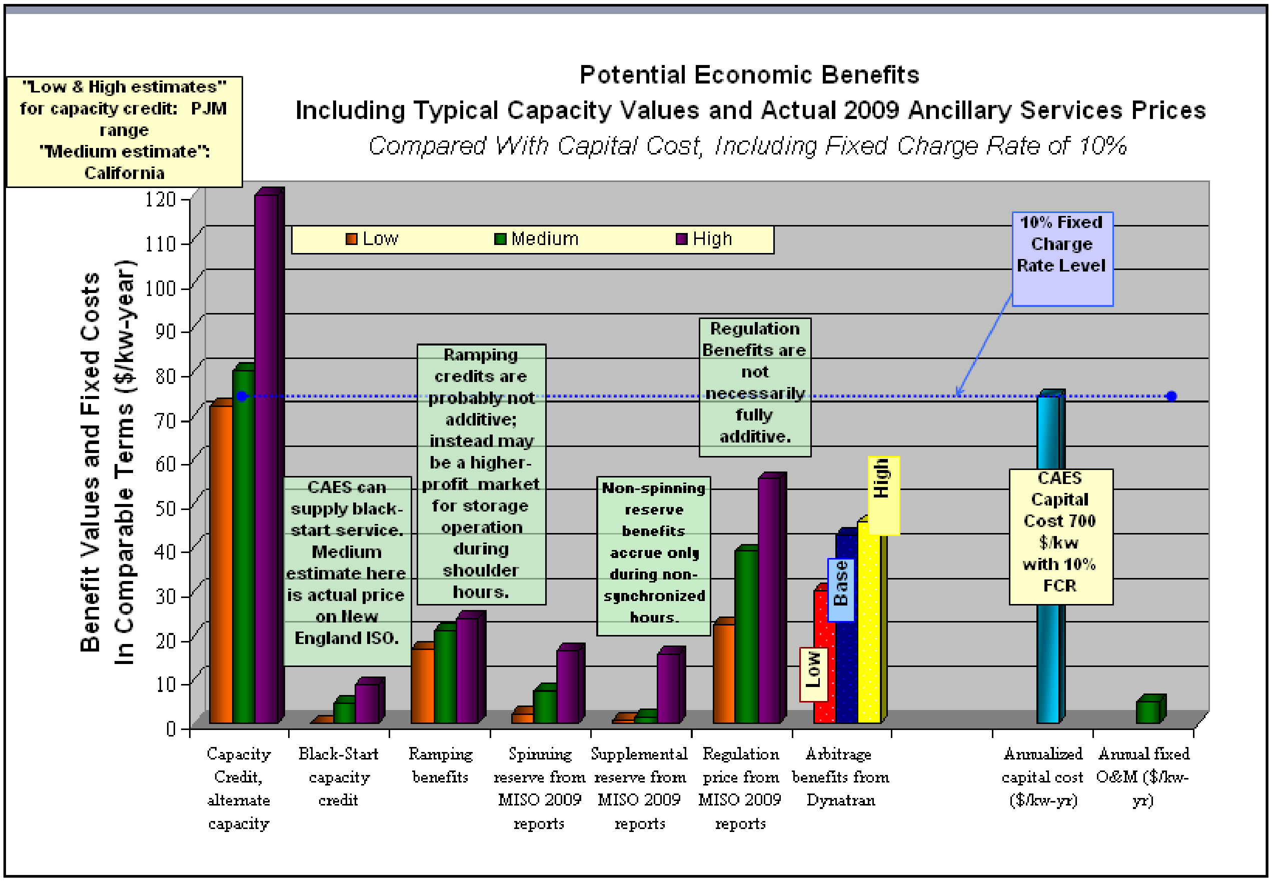
Energy storage plants can also provide ramping service, whether it is supporting down-ramping by taking energy for charging or assisting with up-ramping by discharging as needed. Scheduling storage for ramping service is likely a decision made by comparing prices for that ancillary service with prices available for energy arbitrage.

Frequency regulation service is appropriate for most energy storage plant's, but does not necessarily add directly to energy-market dispatch. For example, a portion of the energy storage plants discharge/generating capacity could be reserved for frequency regulation service, leaving the remaining capability free for energy arbitrage or other ancillary-service markets.

DYNATRAN allows a user with access to pricing information for ancillary service markets or system capacity markets to model the effects of those opportunities on the storage plant's overall benefits. Just as for hourly prices, the user may input hourly schedules of prices for ancillary services, designating key characteristics to control the application of each market and designating each as adding to arbitrage benefits or competing with them on an economic basis. The basic energy storage plant schedule is first established by the energy arbitrage analysis. Ancillary services benefits are computed on the basis of how the plant has been dispatched for arbitrage. For example, if the energy storage plant is producing on-peak energy for the required number of hours per week, capacity credits may be earned. If ramping operation increases the value of energy discharge in shoulder hours, over discharging in peak hours, then the ramping operation replaces the arbitrage operation, capturing the added benefits but not simply adding the two potential sources of benefits.

Whether computed hour by hour as a part of the DYNATRAN simulation or estimated broadly after processing with the model, the range of potential benefits from energy storage can be compared and discussed. For example, Figure D-5 shows a wide array of potential economic benefits from a CAES installation, incorporating the capital cost of the storage system, comparing that with other sources of capacity, and providing a range of estimates for each possible ancillary service market, in addition to the basic energy arbitrage benefits for a range of future price forecast scenarios.

Figure B-5: Comparing Potential Economic Benefits of Storage



Source: EPRI

Task 2: Commercialization Plan

EPRI estimates, based on past experience developing DYNATRAN, that $2 million would be required to develop and commercialize software with similar capability as DYNATRAN. In addition, one full-time person at a loaded cost of approximately $150,000 per year would be required to provide software support services to users on an ongoing basis. Please refer to Task 5 below for an outline of the key steps necessary to develop and commercialize the required software.

Task 3: List of Software Suppliers

The following is a partial list of vendors (in alphabetical order) that are likely to be able to develop a code like DYNATRAN:

- Abacus Solutions
  24704 Voorhees Drive
  Los Altos Hills, CA 94022
  650.941.1728

info@abacussolutionsinc.com
http://www.abacussolutionsinc.com/

- Crossmark
  5100 Legacy Drive
  Plano, Texas 75024
  469-814-1000
  http://www.crossmark.com/

- Energy Management Associates
  160 Beech Street
  Franklin, MA 02038
  508.533.1128
  info@energymgtassoc.com
  http://www.energymgtassoc.com

- Perot Systems (acquired by Dell Services)
  http://www.perotsystems.com/

Task 4: Time Interval to Develop and Commercialize Software

EPRI estimates that a total of 24 months would be the minimum time required to develop and commercialize the required software. Please see Task 5 below for more information on a schedule for development and commercialization of this software.

Task 5: Implementation Plan to Commercialize the Software

A project to develop, commercialize, and implement the necessary software would consist of the following steps (with estimated time periods in parentheses). Note that some tasks overlap; hence, the total adds to more than 24 months.

- Develop and issue a request for proposals (RFP) to develop, commercialize, implement, and support the needed software (1 month to develop, 1 month for vendors to respond).
- Evaluate responses to the RFP from vendors and select a contractor (1 month).
- Negotiate with the selected contractor and enter into an agreement with the contractor (1 month).
- Define and develop test cases (including specification of all input data) for use in testing the software code during development (2 months).
- Develop the code and ensure compliance with all applicable software standards (8 months).
- Develop software user and administrator documentation (3 months).
- Run test cases to refine and calibrate the code against industry accepted benchmarks (2 months).

- In parallel, develop a user friendly graphical user interface (GUI) for the code that includes on-line help and other aspects of commercialized code (6 months).
- Ensure that the code and GUI runs properly on various operating systems, including Microsoft Windows Vista, Windows XP, and Windows 7 (and later issue upgrades that operate on emerging operating systems) (2 months).
- Test the code to ensure the final version provides accurate results, and test the GUI with potential user audiences to ensure ease of use (3 months).
- Assemble marketing personnel; and develop and implement a marketing plan for the sales and marketing of the software (1 month).
- Develop marketing and sales materials; establish a web site; assemble a sales force; leverage alliances and channel partners (2 months).
- Develop training materials for users; develop and implement training sessions with example test cases at user sites (2 months).
- Establish a software user's group, encourage user participation in this group to exchange ideas for software improvement and best practices for software use (1 month).