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Energy Storage Benefits and Market Analysis Handbook

A Study for the DOE Energy Storage Systems Program

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Abstract

This Guide describes a high level, technology-neutral framework for assessing potential benefits from and economic market potential for energy storage used for electric utility-related applications.

In the United States use of electricity storage to support and optimize transmission and distribution (T&D) services has been limited due to high storage system cost and by limited experience with storage system design and operation. Recent improvement of energy storage and power electronics technologies, coupled with changes in the electricity marketplace, indicate an era of expanding opportunity for electricity storage as a cost-effective electric resource.

Some recent developments (in no particular order) that drive the opportunity include:
1) states' adoption of the renewables portfolio standard (RPS), which may increased use of renewable generation with intermittent output, 2) financial risk leading to limited investment in new transmission capacity, coupled with increasing congestion on some transmission lines, 3) regional peaking generation capacity constraints, and 4) increasing emphasis on locational marginal pricing (LMP).

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Definitions

Application – A specific way or ways that energy storage is used, to satisfy a specific need; how/for what energy storage is used.

Arbitrage – See Bulk Electricity Price Arbitrage.

Benefit – See Financial Benefit.

Beneficiaries – Entities to whom financial benefits accrue due to use of a storage system**.**

Bulk Electricity Price Arbitrage (Arbitrage) – Purchase of inexpensive electricity during off-peak periods when demand for electricity is low, to charge the storage plant so that the low priced energy can be used or sold at a later time when demand/price for electricity is high.

C&I – Commercial and Industrial (C&I) energy end-users.

Carrying Charges – The annual financial requirements needed to service debt or equity capital used to purchase and to install the storage plant, including tax effects. For utilities, this is the revenue requirement. See also Fixed Charge Rate.

Combined Applications – Energy storage used for two or more compatible applications.

Combined Benefits – Sum of all benefits that accrue due to use of an energy storage system, irrespective of the purpose for installing the system.

Discharge Duration – Total amount of time that the storage plant can discharge, at its nameplate rating, without recharging. Nameplate rating is the nominal full load rating, not "emergency," "short duration," or "contingency" rating.

Discount Rate – The interest rate used to discount future cash flows to account for the time value of money. For this document the standard assumption value is 10%.

Economic Benefit – The sum of all *financial* benefits that accrue to all beneficiaries using storage. For example, if the average *financial* benefit is $100 for 1 million storage users then the *economic* benefit is $100 * 1 million = $100 Million of *economic* benefit. See Financial Benefit.

Efficiency (**Storage Efficiency**) – See Round Trip Efficiency.

EPRI – Electric Power Research Institute.

Financial Benefit (Benefit) – Monies received and/or cost avoided by a specific beneficiary, due to use of energy storage.

Financial Life – This is the plant life assumed when estimating lifecycle costs and benefits. A plant life of 10 years is assumed for lifecycle financial evaluations in this document (i.e. 10 years is the standard assumption value).

Fixed Charge Rate – The Fixed Charge Rate is used to convert capital plant installed cost into an annuity equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes. The standard assumption value for Fixed Charge Rate is 0.13 for utilities.

Price Inflation Rate (Inflation) – The annual average rate at which the price of goods and services increases during a specific time period. For this document, inflation is assumed to be 2.5% per year.

Lifecycle – See Financial Life.

Lifecycle Benefit – Present value of financial benefits that are expected to accrue over 10 years for a storage plant.

Market Estimate – The estimated amount of energy storage capacity (MW) that will be installed. For this document, market estimates are made for a ten year period. Market estimates reflect consideration of prospects for lower cost alternatives to compete for the same applications and benefits. (For context, the Market Estimate is a portion of the Maximum Market Potential.)

Maximum Market Potential – The maximum potential for actual sale and installation of energy storage, estimated based on reasonable assumptions about technology and market readiness and trends, and about the persistence of existing institutional challenges. In the context of this document, it is the plausible market potential, for a given application. (For context, the Maximum Market Potential is a portion of the Market Technical Potential.)

Market Technical Potential – The estimated maximum possible amount of energy storage (MW and MWh) that could be installed over 10 years, given purely technical constraints.

Plant Rating (Rating) – Storage plant ratings include two primary criteria: 1) *Power*: nominal power output and 2) *Energy*: the maximum amount of energy that the system can deliver to the load without being recharged.

Present Value Factor (PV Factor) – A number used to convert an annual financial payment into the present value for a series of such equal payments. A PV Factor is a function of a specific combination of a) investment duration (life), b) financial escalation rate (e.g., inflation), and c) discount rate. The standard assumption value for this criterion is based on a ten year life, 2.5% inflation, and 10% discount rate. The corresponding PV Factor is 7.17.

Revenue Requirement – For a utility, the amount of annual revenue required to pay carrying charges for capital equipment and to cover expenses including fuel and maintenance. See also Carrying Charges and Fixed Charge Rate.

Round Trip Efficiency – The amount of electric energy output from a given storage plant/system per unit of electric energy input.

Standard Assumption Values (Standard Values) – Standardized/generic values used for example calculations. For example, financial benefits are calculated based on the following standard assumption values: a 10 year lifecycle, 10% discount rate, and 2.5% annual inflation. See also Standard Calculations.

Standard Calculations – Methodologies for calculating benefits and market potential – used in conjunction with Standard Assumption Values.

Storage Discharge Duration – See Discharge Duration.

Storage System Life (System Life) – the period during which the storage system is expected to be operated. For this document, the Storage System Life is equal to the Financial Life.

1. Introduction

1.a. About This Document

This document characterizes electric energy storage applications and related benefits, including a description of means to estimate benefits. It also describes criteria and a framework for estimating market potential and provides maximum market potential estimations for California.

Though much of the data used and results shown in this report are California-specific – being the result of a California-based study – it is possible to extrapolate the methodology to other states, given the availability of the necessary data or even estimates thereof. Some sources for data that are included in the Appendix.

The intended audience for this document includes: 1) persons needing a framework for making a first cut estimate of benefits for a specific storage project, and 2) energy storage technology or project developers requiring high-level estimates of viable price points (based on benefits) and/or maximum market potential for their products.

As its title implies, this report focuses on 1) the benefits associated with use of energy storage, and 2) a high level characterization of the market potential for energy storage <u>without</u> regard to specific technologies or their cost.

For information about storage technologies' costs, readers could begin by consulting a report by Schoenung *et. al.*, *Long- versus Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study*, recently published by Sandia National Laboratories. [17]

1.b. Philosophy

When evaluating specific opportunities to develop energy storage related products or services, it is prudent to develop a credible estimate of the prospective demand for, and financial benefit associated with, a specific application or combination of applications.

As a way to generalize the evaluation, the authors have provided analytical approaches that balance the need for accuracy and precision with the cost to perform rigorous benefits assessments and market projections. The goal is to provide insights needed to undertake a first-cut evaluation of the benefits and markets for storage systems.

Specifically, this document 1) provides guidance and standard assumption values (standard values) to use for calculating benefits associated with storage plants, 2) describes and illustrates use of benefit cost ratios to evaluate financial viability of storage and 3) provides guidance about making an initial estimate of market potential.

Given the interest in use of consistent bases, standard assumption values are provided for most of the important criteria used for benefit calculations and market estimates. However, almost certainly, other assumptions and perhaps even other calculation methods will be appropriate for specific circumstances. The reader is encouraged to use the methodologies and data presented here as a starting point for further analyses.

The presentation in this document is technology neutral, though there is some coverage of technical requirements for storage systems used for specific applications. Many existing resources can be used to determine the cost for, and technical viability of, specific technologies [17] [23].

1.c. Technical Notes

True, Apparent, and Reactive Power

For the purposes of this document, units of kW (real power) are used universally when kVA (apparent power) or even kVAR (reactive power) may be the most "technically" correct units to use. But given the degree of accuracy possible for the market and benefit estimations, the distinction between these units has relatively little consequence in terms of the results.

Nominal versus "Emergency" Power Rating

Some types of storage systems can discharge at a relatively high rate for relatively short periods of time (often referred to as "emergency" rating). For this document the discharge rate used is what would commonly be referred to as design rating or nominal rating: the rate at which energy is normally discharged.

For example, a storage device can operate at a nominal 1 MW, for 3 hours at 80% efficiency. The same plant can provide 1.5 MW for up to 10 minutes, at 65% efficiency. For this document, the storage system power rating for the system just described would be 1 MW.

1.d. Summary of Key Assumption Values

For the reader's convenience, Table 1. provides a summary of key standard assumption values used for evaluating benefits, market potential, and total economic benefits from storage used for specific applications and/or for specific benefits. The table is based solely on California situations and applications. Each of these applications, and the derivation of the parameters assumed or calculated, will be described in detail in the remainder of this report.

Table 1. Summary of Key Standard Assumptions and Calculations for Applications of Storage in the State of California

Application/Benefit	Discharge Duration* Minimum	Discharge Duration* Highest	Lifecycle Financial Benefits ($/kW)	Maximum 10-year Market Potential (MW)	Ten-year Economic Benefits ($Million)**
Bulk Electricity Price Arbitrage	1	10	200 to 300	735	147 to 220
Central Generation Capacity	4	6	215#	3,200	688
Ancillary Services	1	5	72***	800	58
Transmission Support	2 Seconds	5 Seconds	169	1,000	169
Reduce Transmission Access Requirements	1	6	72***	3,200	230
Transmission Congestion Relief	2	6	72***	3,200	230
Distribution Upgrade Deferral 50th Percentile of Benefits	2	6	666#	804	536
Distribution Upgrade Deferral 90th Percentile of Benefits	2	6	1,067#	161	172
Transmission Upgrade Deferral	4	6	650#	1,092	710
Time-of-Use Energy Cost Management	2	see tariff	1,004	4,005	4,021
Demand Charge Management	6	11	465#	4,005	1,862
End-user Electric Service Reliability	0.25	5	359#	4,005	1,438
Electric Service Power Quality	10 seconds	1 Minute	717#	4,005	2,872
Renewables Capacity Firming	6	10	172##	1,800	310
Renewables Contractual Time-of-Production Payments	6	10	655##	500	328

*Hours unless other units are specified.
**Over ten years, based on lifecycle benefits times maximum market potential (market *estimates* will be lower).
***Placeholder values. The actual benefit was not estimated.
#Does not include incidental energy-related benefit.
##Wind generation.

2. Electric Energy Storage Applications

2.a. Applications Overview

This section describes thirteen application types.

For convenience, applications are grouped into three categories:

- Grid System
- End-user/Utility Customer
- Renewables

The 13 applications (grouped by category) are:

<u>Grid System</u>

1. Bulk Electricity Price Arbitrage (arbitrage)
2. Central Generation Capacity (generation capacity)
3. Ancillary Services
4. Transmission Support
5. Reduce Transmission Capacity Requirements
6. Reduce Transmission Congestion (transmission congestion)
7. Transmission and Distribution Upgrade Deferral (T&D deferral)

<u>End-user/Utility Customer</u>

8. Time-of-Use Energy Cost Management
9. Demand Charge Management
10. Electric Service Reliability (reliability)
11. Electric Service Power Quality (PQ)

<u>Renewables</u>

12. Renewables Capacity Firming (renewables capacity)
13. Renewables Contractual Time-of-Production Payments

It is very important for readers to note the distinction made in this document between applications and benefits. <u>Applications</u> (listed above) are specific purposes for which storage is used. <u>Benefits</u> involve money: they accrue because storage is used. (In this document, a benefit may be a revenue stream, a cost reduction, or a cost that may be avoided if storage is used ("avoided cost.")

Furthermore, storage deployed to serve a specific application may provide any number of <u>benefits</u>. As an example: an energy end-user stores energy off-peak for discharge on-peak (the time-of-use electricity cost reduction application). As the application name implies, the primary benefit is electric energy cost reduction. Depending on circumstances, the energy storage plant could provide another benefit: reduced demand charges. It could also provide benefits associated with improved electric service reliability or power quality.

2.b. General Technical Considerations

Storage System Discharge Duration

The storage plant discharge duration is, of course, an important criterion both with respect to technical viability for a given application and the plant cost. To the extent possible, this document includes guidance about how to determine the necessary discharge duration for a specific circumstance.

At the highest level, plants with two or more hours of storage (discharge duration) are preferred. Application-specific guidance and standard assumptions are provided in respective report sections that follow.

For more detailed coverage of storage sizing readers should refer to a report developed by Sandia National Laboratories entitled *Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral, a Study for the DOE Energy Storage Program*. [28]

Storage System Minimum Reliability

Like power rating and discharge duration, storage system reliability requirements are circumstance-specific. Little guidance is possible. The project design engineer is responsible for designing a plant that provides enough power and is as reliable as necessary to serve the respective application.

2.c. Grid System Applications

Application #1 Bulk Electricity Price Arbitrage

Application Overview

Bulk electricity price arbitrage (arbitrage) involves the purchase of inexpensive electricity available during periods when demand for electricity is low, to charge the storage plant, so that the low priced energy can be used or sold at a later time when the price for electricity is high. (Note: In this context, sales are mostly or entirely to end-users, though sales could be made to other entities via the wholesale/commodity electricity marketplace.)

Technical Considerations

For the arbitrage application, the plant storage discharge duration is determined based on the incremental benefit associated with being able to make additional buy low – sell high transactions during the year versus the incremental cost for additional energy storage (discharge duration).

Section 4. includes more details about the trade-off between the incremental benefit for additional discharge duration, given a plant with a specified variable maintenance cost and efficiency.

The standard assumption for this application for minimum discharge duration for this application is two hours, although benefits are presented for a range of energy storage discharge durations later in this report.

Although each case is unique, if the plant used for this application is in the right location and if the plant is discharged at the right times, it could also serve the following applications: T&D deferral, transmission congestion relief, reliability, PQ, or ancillary services.

Application #2 Central Generation Capacity

Application Overview

Depending on the circumstances in a given electric supply system, energy storage could be used to defer and/or to reduce the need to buy new generation capacity and/or to "rent" generation capacity in the wholesale electricity marketplace. Storage is used in lieu of adding central generation capacity. In many areas of the U.S., the most likely type of new generation plant "on the margin" is a natural gas fired combined cycle power plant costing an estimated $500/kW. Peaking capacity costs somewhat less.

The marketplace within which generation capacity charges can be exchanged is evolving. Historically, generation capacity has been bought and sold in the wholesale marketplace. That marketplace is opening up to others. A key development is access to the electric system's "wires" (transmission and distribution systems): without such access, power produced by distributed energy storage (and generation) cannot be delivered to the electric system for sale.

Technical Considerations

The annual hours of operation, frequency of operation, and duration of operation for this application are all circumstance-specific. That makes generalizations about storage discharge duration difficult for this application.

In addition, a key criterion affecting discharge duration for this application is the way that generation capacity is priced. For example, if capacity is priced on a per hour basis then storage plant duration is flexible. If prices require that the capacity resource be available for a specified duration for each occurrence (e.g., five hours) or require operation during an entire time period (e.g., 12:00 noon – 5:00 p.m., 5 hours) then the storage plant discharge duration must accommodate those requirements.

Depending on location and other circumstances, storage used for this application may be compatible with the following applications: T&D deferral, reliability, transmission support, PQ, and ancillary services.

Application #3 Ancillary Services

Application Overview

The primary function of the electric power system is to supply electric energy from generators and deliver it to customers via the transmission and distribution systems. Ancillary services are defined by the Federal Energy Regulatory Commission (FERC) as those services necessary to support the delivery of electricity from seller to purchaser while maintaining the integrity and reliability of the interconnected transmission system ("the network").

Table 2. List of Ancillary Services and Their Common Definitions

1. System Control	Scheduling generation and transactions ahead of time, and controlling some generation in real time to maintain generation/load balance.
2. Reactive Supply & Voltage Control	The generation or absorption of reactive power from generators to maintain transmission system voltages within required ranges.
3. Regulation	Minute-by-minute generation/load balance within a control area to meet NERC standards.
4. Spinning Reserve	Generation capacity that is on-line but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. "Frequency-responsive" spinning reserve responds within 10 <u>seconds</u> to maintain system frequency.
5. Supplemental Reserve	Generation capacity that may be off-line or curtailable load that can respond within 10 minutes to compensate for generation or transmission outages.
6. Energy Imbalance	Correcting for mismatches between actual and scheduled transactions on an hourly basis.
7. Load Following	Meeting hour-to-hour and daily load variations.
8. Backup Supply	Generation available within an hour, for backing up reserves or for commercial transactions.
9. Real Power Loss Replacement	Generation that compensates for losses in the T&D system.
10. Dynamic Scheduling	Real-time control to electronically transfer either a generator's output or a customer's load from one control area to another.
11. Black Start	Ability to energize part of a grid without outside assistance after a blackout occurs.
12. Network Stability	Real-time response to system disturbances to maintain system stability or security.

[Source: Federal Energy Regulatory Commission]

Technical Considerations

Resources used to provide ancillary services must be reliable and must be capable of rapid start-up and ramping. They must also have high quality, stable (power) output characteristics. Storage used to provide some ancillary services may also be used for other applications including PQ, reliability and possibly others.

Application #4 Transmission Support

Application Overview

Energy storage may be used to improve transmission and distribution systems' performance by compensating for electrical anomalies and disturbances such as voltage sag, unstable voltage, and presence of sub-synchronous resonance. The result is a more stable system with improved performance (throughput).

Generically, this application may be referred to as transmission support. The benefits from transmission support are very situation- and site-specific.

Table 3. lists and briefly describes ways that energy storage can provide such transmission support.

Table 3. Types of Transmission Support

Type	Description
Transmission Stability Damping	Increase load carrying capacity by improving dynamic stability.
Sub-Synchronous Resonance Damping	Increase line capacity by allowing higher levels of series compensation by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies.
Voltage Control and Stability	1. Transient Voltage Dip Improvement Increase load carrying capacity by reducing the voltage dip which follows a system disturbance. 2. Dynamic Voltage Stability Improve transfer capability by improving voltage stability.
Under-frequency Load Shedding Reduction	Reduce load shedding needed to manage under-frequency conditions which occur during large system disturbances.

Adapted from information provided by the Electric Power Research Institute [1, 2, 6]

Technical Considerations

To be used for transmission support, energy storage must be capable of: 1) sub-second response, 2) operation at partial states of charge, and 3) many charge-discharge cycles. Storage used for this application must also be very reliable.

Typical discharge durations for this application are between one and twenty seconds. For storage to be most beneficial as a transmission support resource, it should provide both real and reactive power. [6]

Application #5 Reduce Transmission Capacity Requirements

Application Overview

To reduce transmission capacity requirements, low-priced off-peak electric energy may be stored and then discharged during peak demand periods, reducing the load on the transmission system.

Technical Considerations

The discharge duration needed for this application depends on the prevailing market conditions and the way that transmission access is priced. In some regions, “postage stamp” rates apply. In those cases, transmission prices are the same during all hours of year. In other regions, time-specific access charges may apply. Prices may be applied hourly, daily, or monthly.

Depending on location and other circumstances, storage used for this application may be compatible with the arbitrage and/or the T&D deferral application. It could also provide customer reliability, transmission support, improved PQ, and/or ancillary services.

Readers should note that this application has a significant overlap with the transmission congestion relief application.

Application #6 Transmission Congestion Relief

Application Overview

In many areas, transmission capacity additions are not keeping pace with the growth in peak electric demand so transmission systems are becoming congested during periods of peak demand. That drives increasing transmission access charges and may lead to increased use of congestion charges or “locational marginal pricing” for electric energy (LMP).

Storage could be used to avoid congestion-related costs and charges, especially if the charges become onerous due to significant transmission system congestion. To do that, energy stored off-peak is discharged to reduce transmission capacity requirements during peak demand periods.

Technical Considerations

The discharge duration needed for the transmission congestion relief application cannot be generalized easily, given all the possible manifestations such as those described above.

As with the T&D deferral application, it may be that there are just a few individual hours throughout the year when congestion charges apply. Or, there may be a few occurrences during a year when there are two or three consecutive hours of transmission congestion. Also, congestion charges may be applied like demand charges: payments are made for maximum demand during certain hours during certain months. Congestion charges may vary from year-to-year because supply and demand are always changing.

The standard discharge duration is assumed to be two hours for this application.

Depending on location and other circumstances, a storage plant used for this application may be compatible with the arbitrage and/or the T&D deferral application. It could also serve the reliability, PQ, transmission support, and ancillary services applications.

Readers should note that this application has a significant overlap with the reduce transmission capacity requirements application.

Application #7 Transmission and Distribution Upgrade Deferral

Application Overview

Transmission and distribution (T&D) upgrade deferral involves delaying utility investments in transmission and/or distribution system upgrades by using relatively small amounts of storage.

Consider a T&D system whose peak electric loading is approaching the system's load carrying capacity (design rating). In some cases, installation of a small amount of energy storage downstream from the nearly overloaded T&D node will defer the need for a T&D upgrade.

As a specific example: a 15 MW substation is operating at 3% below its rating. Load growth is about 2%/year. Engineers plan to upgrade the substation next year by adding 5 MVA of additional capacity.

As an alternative, engineers could consider installing enough storage to meet the expected load growth for next year, plus any appropriate engineering contingency (it may not be prudent to install "just enough" storage, especially if there is uncertainty about load growth).

For the 15 MW substation, at 2% load growth rate, during the next year load growth is about 300 kW (2% * 15 MW). For illustration, adding a 25% engineering contingency means that the storage plant would have to be about 375 kW. (In this example assume that the engineers believe that storage discharge duration of 2 hours is sufficient.)

The key concept is that a small amount of storage can be used to delay a large "lump" investment in T&D equipment. Among other effects, this approach: 1) reduces overall cost to ratepayers, 2) increases utility asset utilization, 3) allows use of the capital for another important project, and 4) reduces financial risk associated with large lump investments whose capacity may never be used.

Technical Considerations

Discharge duration is a critical design criterion for the T&D deferral application. It is also challenging to estimate. It may require interaction with utility engineers, engineers that design and/or operate distribution systems. The standard discharge duration is assumed to be two hours.

In short, the energy storage must serve enough load, for as long as needed, to keep loading on the equipment at the respective T&D node below a specified maximum at all times.

For most circuits, the highest loads occur on just a few days per year, for just a few hours per year. Often the highest annual load occurs on one specific day whose peak is somewhat higher than any other day.

Depending on location and other circumstances, a plant used for this application could also serve the arbitrage and/or transmission congestion relief applications; it may also provide improved electric service reliability, PQ improvement, and/or ancillary services.

2.d. Customer/End-use Applications

Application #8 Time-of-Use Energy Cost Management

Application Overview

The time-of-use (TOU) electricity cost management application (time-of-use application) involves storage used by energy end-users (utility customers) to reduce their overall costs for electricity. Customers charge the storage during off-peak time periods when electric energy price is low, then discharge the energy during times when on-peak (time-of-use) energy prices apply.

This application is similar to arbitrage though electric energy prices are based on the customer's tariff whereas at any given time the price for electric energy for arbitrage is the prevailing wholesale price.

For the example, Pacific Gas and Electric's (PG&E's) Small Commercial Time-of-Use A-6 tariff was used. It applies during the months of May to October, Monday through Friday. Commercial and industrial electricity end-users whose peak power requirements are less than or equal to 500 kW are eligible for the A6 tariff.

As shown in Figure 1., energy prices are about 32 ¢/kWh on-peak (noon to 6:00 pm). Prices during partial-peak (8:30 am to noon and 6:00 pm to 9:30 pm) are about 15 ¢/kWh, and during off-peak (9:30 pm to 8:30 am) prices are about 10 ¢/kWh.

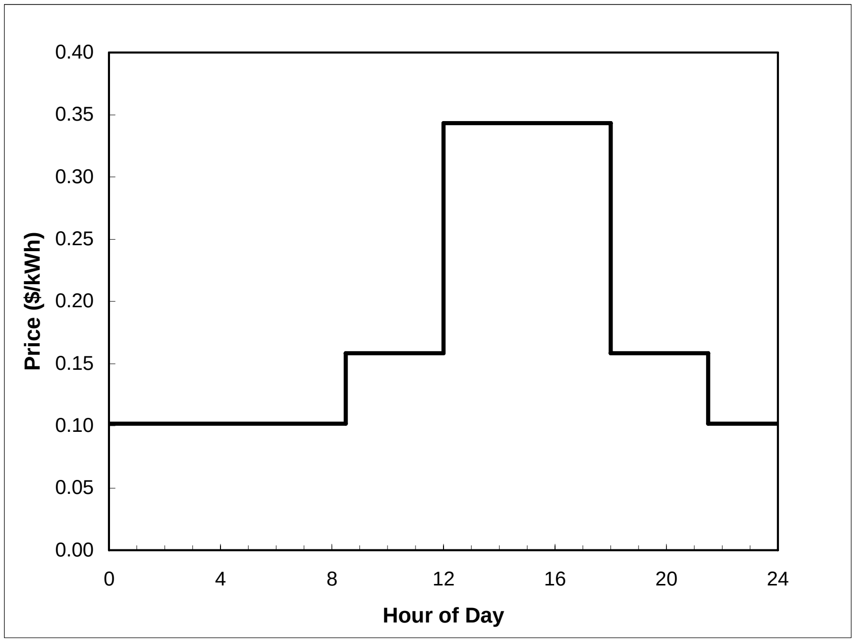

Figure 1. Summer Energy Prices for PG&E's Small Commercial A-6 Time-of-use Rate

Technical Considerations

The maximum discharge duration for this application is determined based on the relevant tariff. For example, for the A-6 tariff there are six on-peak hours (12:00 noon to 6:00 p.m.). The standard assumption for this application is six hours of discharge duration.

This application may be compatible with the energy arbitrage application and could provide ancillary services benefits, if end-users may participate in the wholesale energy marketplace.

Depending on overlaps between on-peak energy prices and times when peak demand charges apply, the same plant might also be compatible with the demand charge management application. It could also provide benefits associated with improved end-user PQ and improved electric service reliability.

Similarly, depending on the plant's discharge duration and when discharge occurs, the storage plant may be compatible with the T&D deferral application and could also provide improved (grid) transmission support, if utilities are so motivated and are allowed to share related benefits.

Application #9 Demand Charge Management

Application Overview

Energy storage could be used by energy end-users (utility customers) to reduce their overall costs for electric service by reducing on-peak demand charges. To avoid demand charges (associated with a given kW of peak load), customers must avoid using power during peak demand periods, which are the times when demand charges apply.

Typically, demand charges apply during the summer months on weekdays. In order to avoid a monthly demand charge, load must be reduced during all on-peak hours. In many cases, if load is present for just one 15 minute period, during times and months when peak demand charges apply, the monthly demand charge is not avoided. In an increasing number of cases there is a demand charge for the maximum annual demand as well.

As shown in Figure 2., energy end-users charge the storage during off-peak time periods when the electric energy price is low.

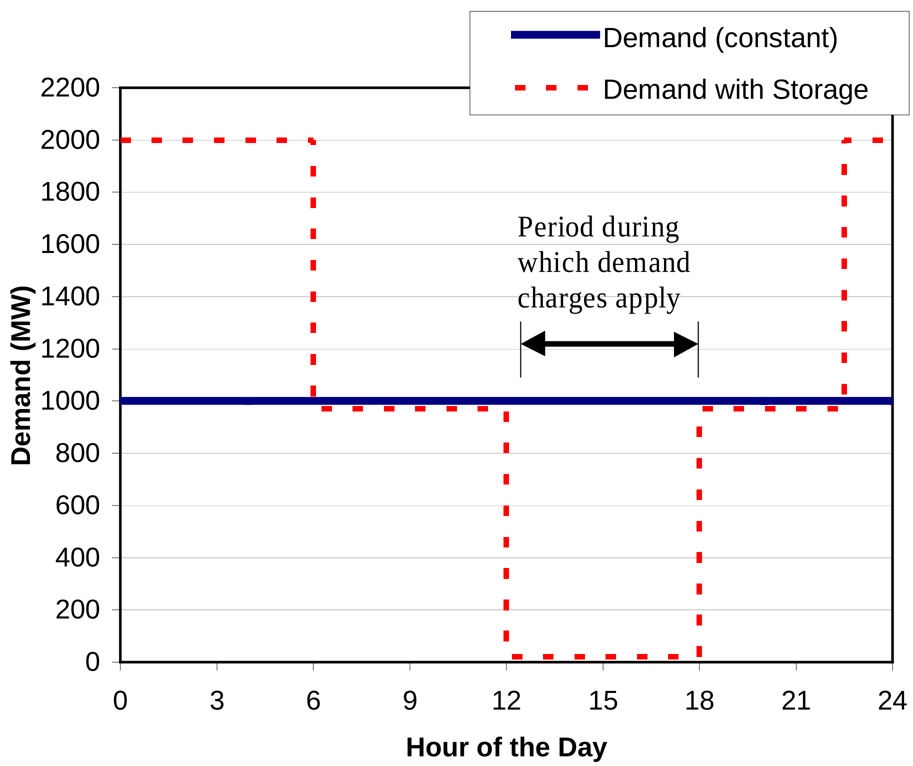

Figure 2. On-Peak Demand Charge Reduction Using Energy Storage

The stored energy is used to serve demand during times when demand charges apply. Typically, energy storage must discharge for five to six hours for this application, depending on provisions of the applicable tariff.

The example shown in Figure 2 involves a load that is constant at 1 MW for three shifts. At night, when energy price is low, the facility's load (on the grid) essentially doubles: the batteries store energy at a rate of one MW and the normal demand from operations requires another MW of power. The storage system is 80% efficient, so to discharge for six hours it must charge for 6/80% = 7.5 hours.

Technical Considerations

For this application the storage plant discharge duration is driven by the applicable tariff. For example, for PG&E's E-19 Medium General Demand-Metered TOU tariff, there are six on-peak hours (12:00 noon to 6:00 pm).

The standard assumption for this application is six hours of discharge duration.

Though each circumstance is different, a use of storage for this application may be compatible with the energy arbitrage application and could provide ancillary services benefits if end-users are allowed to participate in the wholesale energy marketplace.

This application may be also compatible with the T&D deferral application and could also provide transmission support, if utilities are motivated to and allowed to share related benefits. The times when demand charges apply must coincide with demand on the transmission and/or local distribution system.

The same plant might also be compatible with the time-of-use energy cost reduction application, if storage is discharging during the entire daily duration of the period when demand charges apply. The plant could be used for the PQ and reliability applications.

Application #10 Electric Service Reliability

Application Overview

The electric service reliability application entails use of energy storage to provide highly reliable electric service. In the event of a complete power outage lasting more than a few seconds the storage system provides enough energy to a) ride through outages of extended duration or b) to complete an orderly shutdown of processes, c) transfer to on-site generation resources.

Technical Considerations

The discharge duration required is based on situation-specific criteria. If an orderly shutdown is the objective, then discharge duration may be an hour or more. If an orderly transfer to a generation device is the objective, a few minutes of discharge duration is needed.

Storage used for this application must yield power with sufficient quality, reliably.

This application may be compatible with the power quality application and possibly T&D support or ancillary services.

Application #11 Power Quality

Application Overview

The electric service power quality application involves use of energy storage to protect loads downstream against short duration events which affect the quality of power delivered to the load. Some manifestations of poor power quality include:

- variations in voltage magnitude, (e.g., short-term spikes or dips, longer-term surges, or sags)
- variations in the primary 60 cycles/sec frequency at which power is delivered
- low power factor (voltage and current excessively out of phase with each other)
- harmonics, (i.e., the presence of currents or voltages at frequencies other than the primary frequency)
- interruptions in service, of any duration, from a fraction of a second to minutes

Technical Considerations

Typically the discharge duration required for the power quality application range from a few seconds to about one minute.

2.e. Renewables Applications

Application #12 Renewables Capacity Firming

Application Overview

For this application, storage is charged with energy from renewables during periods when demand for electricity is low (and thus the value of electricity is low), so that stored energy may be discharged during peak demand periods (when the value is high). This is done primarily to provide power (capacity) in lieu of central generation.

Typically, this application involves a contract and/or power purchase agreement.

Technical Considerations

Depending on the location, storage used to firm up renewables generation could also provide other benefits: 1) revenues from or avoided cost for on-peak energy, 2) avoided/deferred need to build transmission capacity, 3) avoided transmission access or congestion charges, 4) transmission support, and 5) ancillary services.

Typical utility peak price periods extend from 12:00 noon to 6:00 pm on summer weekdays. Therefore, the assumed discharge duration for a capacity resource is six hours.

It is assumed that storage systems' power rating is equal to the nameplate rating of the power plant. For example, a 1 MW wind turbine is paired with a storage plant whose power rating is also 1 MW (irrespective of discharge duration).

Application #13 Renewables Contractual Time-of-production Payments

Application Overview

This application involves storing of electric energy from renewables during periods when demand for electricity is low (and thus value of electricity from renewables is low). The energy is discharged during peak demand periods when the value is high.

For the entity purchasing the energy, this is done primarily to provide the energy in lieu of producing the same energy from a non-renewable central generation facility.

It is common for this application to involve a contract and/or power purchase agreement.

Technical Considerations

Depending on where the storage is located, if it is used in conjunction with bulk renewables resources, then the benefits may also include: 1) avoided/deferred need to build or to purchase other generation capacity, 2) avoided/deferred need to build transmission capacity, 3) avoided transmission access charges, 4) avoided transmission congestion charges, 5) transmission support, and 6) ancillary services.

The discharge duration for this application is circumstance-specific. It depends mostly on the terms of the purchase agreement. The minimum discharge duration for this application is assumed to be two hours.

2.f Application-Specific Discharge Durations

Table 4. lists standard assumption values specific to each application.

Table 4. Standard Assumption Values for Discharge Duration

Benefit	Discharge Duration Minimum	Discharge Duration Maximum	Note
Bulk Electricity Price Arbitrage (Cost reduction or "Profit")	1 hour	10 hours	Primarily a function of: 1) incremental cost of adding storage versus incremental benefit (benefit from additional transactions) and to a lesser extent, 2) storage efficiency.
Central Generation Capacity (Avoided Cost or "Profit")	4 hours	6 hours	Needed during peak load hours during peak load days.
Ancillary Services (Avoided Cost or "Profit")	1 hour	5 hours	Circumstance, location, and ancillary service-type specific.
Transmission Support (Avoided Cost or "Profit")	2 Seconds	5 Seconds	Location- and support-type-specific.
Avoided Transmission Access Charges	1 hour	6 hours	Very circumstance specific.
Avoided Transmission Congestion Charges	2 hours	6 hours	Region/Location-specific.
Distribution Upgrade Deferral 50th Percentile of Benefits	2 hours	6 hours	Situation-specific; depends mostly on feeder load pattern during peak load days.
Distribution Upgrade Deferral 90th Percentile of Benefits	2 hours	6 hours	Situation-specific; depends mostly on feeder load pattern during peak load days.
Transmission Upgrade Deferral	4 hours	6 hours	Situation-specific; depends mostly on transmission load pattern during peak load days.
Time-of-Use Energy Cost Management	2 hours	see tariff	Maximum discharge duration is based on the applicable tariff: PG&E A6.
Demand Charge Management	6 hours	11 hours	Peak demand period (daily) is based on tariff: PG&E E19 Standard Assumption: Must operate from 12:00 noon to 6:00 p.m. on Summer weekdays.
End-user Electric Service Reliability Reduced Financial Losses	.25 hour	5 hours	Situation-specific, depending upon outage history and end-use type.
Power Quality Reduced Financial Losses	10 Seconds	1 Minute	Very circumstance, location, and customer-type specific.
Renewables Capacity Firming	6 hours	10 hours	Situation-specific. Standard Assumption: need to operate storage from 12:00 noon to 6:00 p.m. on Summer weekdays for system; as few as two hours for distribution capacity.
Renewables Contractual Time-of-Production Payments	6 hours	10 hours	Standard Assumption: Could operate storage from 12:00 noon to 6:00 p.m. on Summer weekdays.

3. Estimating Market Potential

A key facet to evaluating a market opportunity is to estimate market potential This section describes the authors' philosophy for making a high level, first cut estimate of market potential.

3.a. Market Estimation Approach and Philosophy

Readers should note that the discussion herein about market estimation, by design, cannot address the many combinations of market conditions, storage costs, and storage benefits. Since storage costs are not an element of this report, the authors cannot estimate benefit/cost ratios or market sizes; these calculations must be left to the reader, who presumably will have a specific storage device and application in mind.

Instead, what is presented is a generic, three-step process for making market estimates. This process may be used to make market estimates that are high-level, or very detailed and accurate, as needed.

As indicated by the outer square in Figure 3., the first step required when estimating market potential is to ascertain the technical market potential (or technical potential). That is the maximum amount (MW) possible given technical constraints. As an upper bound, the technical potential is the peak electric demand.

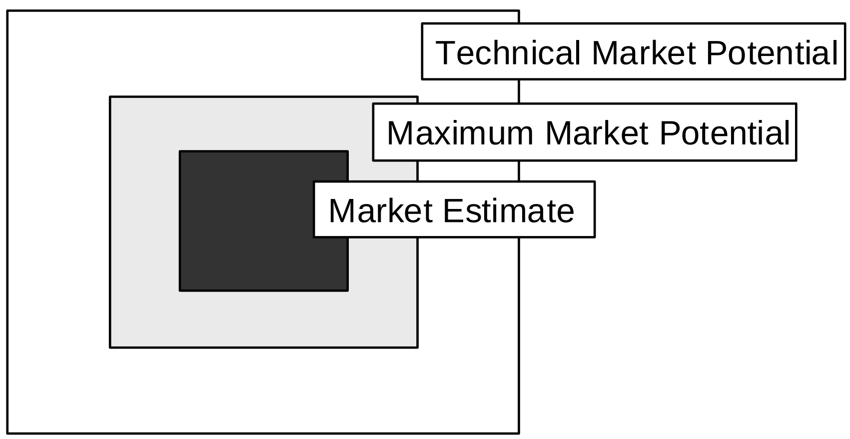

Figure 3. Market Potential and Estimate

Next, the maximum market potential is established, as an upper bound to the actual market potential. It is an estimate of the maximum possible demand given constraints that are practical or institutional in nature such as utility regulations and practices. Maximum market potential is also established without regard to storage cost.

Finally, an estimate could be made of the expected market size (market estimate). As shown in Figure 3., the market estimate is some portion of the maximum market potential. The market estimate reflects the amount of storage that the analyst expects to be deployed, over a given number of months or years (ten years are used for this document), for the specified application or combination of applications, taking the full ownership and operating costs of the specific storage device into account.

As noted above, market estimates may be as detailed and accurate as appropriate. At the very least, various levels of market potential can be tested for reasonableness using various combinations of judgment, knowledge, or preliminary product cost estimates.

Alternatively, bases for estimates could include, for example, sales trends and projections, surveys, analysis of utility capital budget plans, detailed product cost estimates, or market research or intelligence.

3.b. California Electric Demand

A key parameter that underlies the maximum possible market size is the total electric load in California. For details please visit the California Energy Commission website for peak demand projections. The web link below goes directly to an Excel spreadsheet with the projections.

http://www.energy.ca.gov/electricity/2003-01-28_OUTLOOK.XLS

The values in Table 5. below are from the document located at the web link.

Table 5. California Peak Load and Load Growth

California Load, Beginning 2004	57,416 MW
Average Peak Load Growth Rate	2.5% per year
California Load, Ending 2013	73,498 MW
California Load Growth 2004 to 2013	16,081 MW

3.c. Maximum Market Potential for Applications

The maximum market potential is an upper bound to the market estimates. It is established by considering constraints (on market potential) that are practical and institutional. Maximum market potential is established without regard to storage cost.

Consider an example: given the premise that it is unlikely that storage will displace any existing utility equipment, a simplifying assumption (for utility applications) is that the market for new storage to serve electric load is limited to the annual load growth.

For specific applications, other practical or institutional limits on the maximum market potential apply. For example, if the application is for a commercial or industrial customer, then residential customers are not part of the maximum market potential.

Estimates for maximum market potential in California for the thirteen applications listed in Section 2 are shown in Table 6.

Table 6. Standard Assumption Values for Maximum Market Potential in California

Benefit	Maximum Market Potential* MW*	Note
Bulk Electricity Price Arbitrage	735	Maximum Market Potential is 1% of Load in 2013.
Central Generation Capacity (Avoided Cost or "Profit")	3,200	Assume 20% of load growth is for non-baseload generation. 16,000 MW * .2 = 3,200 MW. (Assume that the balance of load growth is served primarily by new combined cycle capacity and by some additional renewables capacity.
Ancillary Services (Avoided Cost or "Profit")	800	PG&E uses a power plant rated at 1,000 kW (e.g. Pittsburg 7) to regulate load of about 20,000 MW. 1,000 MW / 20,000 MW = 5% of total load. 5% * 16,000 MW of load growth = 800 MW. See endnote 15.
Transmission Support (Avoided Cost or "Profit")	1,000	Estimated based on research by the Electric Power Research Institute.
Avoided Transmission Access Charges	3,200	Assume 20% of load growth. 16,000 MW * .2 = 3,200 MW.
Avoided Transmission Congestion Charges	3,200	Assume 20% of load growth. 16,000 MW * .2 = 3,200 MW. See endnote 14.
Distribution Upgrade Deferral 50th Percentile of Benefits	804	Premise: New capacity will not displace existing capacity with useful life. Ten percent of distribution system has peak load that is at or near the equipment's capacity: that is capacity "in-play." Load in-play is 1,608 MW. 50 percent of capacity in-play (804 MW) has annual carrying charges of $50/kW-year.
Distribution Upgrade Deferral 90th Percentile of Benefits	161	Premise: New capacity will not displace existing capacity with useful life. Ten percent of distribution system has peak load that is at or near the equipment's capacity: that is capacity "in-play." Load in-play is 1,608 MW. Ten percent of capacity in-play (161 MW) has annual carrying charges of $80/kW-year.
Transmission Upgrade Deferral	1,092	Assume one "Path 15-like" project statewide during study period: 3,900 MW. Maximum market potential is ten years' load growth (that new transmission line would satisfy, over ten years, if built). Assuming 2.5% load growth rate: 3,900 MW * (1 - ((1.025)^10)) = 3,900 MW * .28
Time-of-Use Energy Cost Management	4,005	2/3 of state total peak demand is from Industrial/Commercial Loads. => 2/3 * 57,416 (peak load in 2,004) = 38,278 MW in-play. 1% / year "market adoption rate."
Demand Charge Management	4,005	Same as above.
End-user Electric Service Reliability Reduced Financial Losses	4,005	Same as above.
Power Quality Reduced Financial Losses	4,005	2/3 of state total peak demand is from Industrial/Commercial Loads. => 2/3 * 57,416 (peak load in 2,004) = 38,278 MW in-play. 1% / year "market adoption rate."
Renewables Capacity Firming	1,800	Existing wind generation capacity in Califormia. See endnote 5.
Renewables Contractual Time-of-Production Payments	500	Qualifying Standard Offer 4 (SO4) contracts, wind generation.

* Over ten years, in California.

In addition to the actual maximum market potentials, the table contains notes about the rationale used to set those values.

These standard assumption values were developed based on a blend of subjectivity, judgment and facts (data). It is believed that they are reasonable; analysts may have better information, insights, or understanding of storage applications. If so, analysts are encouraged to develop their own estimates for maximum market potential.

3.d. Making the Market Estimate

The final step in the market estimation process is to estimate the portion of the maximum market potential that will be realized during the target period (ten years are used, for illustration, in this document) – that is the market estimate.

As noted above, market estimates may be as detailed and accurate as appropriate. At the very least, various levels of market potential can be tested for reasonableness using various combinations of judgment, knowledge, or preliminary product cost estimates.

Alternatively, bases for estimates could include, for example, sales trends and projections, surveys, analysis of utility capital budget plans, detailed product cost estimates, or market research or intelligence.

Some important criteria affecting market estimates for storage systems include, among others: system cost (capital, installation, O&M, etc.), efficiency, marketing costs, and market adoption rates.

Market Estimates: Storage Must be Cost-Effective

One obvious driver of the market potential for storage systems – used for a given application or application(s) – is the value proposition to be demonstrated. Specifically, if the cost for storage will be higher than lifecycle benefits then, of course, no storage systems would be sold. If benefits exceed cost by a large margin, then the amount of storage actually used could be significant.

Market Estimates: Storage Must be Cost-Competitive

As described in Section 4, benefits associated with use of energy storage are estimated irrespective of the specific solution being considered. It is important to note that the competitiveness of a given solution depends on whether there is a lower cost and otherwise viable option.
When establishing the market estimate it is very important to account for the fact that solutions whose costs are not competitive are not attractive candidates. Specifically, storage systems whose costs exceed the cost of another technically viable option (i.e., can provide the same "utility") are not financially competitive solutions.

Market Estimates for Combined Applications and Benefits

In many cases, storage may be used for more than one application (combined applications) or storage used for a specific application may provide more than one financial benefit (combined benefits). (Financial benefits are described in Section 4.)

When making market estimates for these circumstances, it is important that these estimates account for the fact that combining of applications or benefits probably increases storage system benefit ($/kW) but may reduce the overall market potential.

Consider an example: a storage plant is used for the distribution upgrade deferral application. If benefits also accrue for enhanced electric service reliability, then the estimated market is the intersection between the market estimate for distribution deferral and the market estimate for reliability enhancement. That is, only feeders needing upgrading and having reliability-sensitive loads would be candidates for this combined application.

This concept is illustrated graphically in Figure 4.

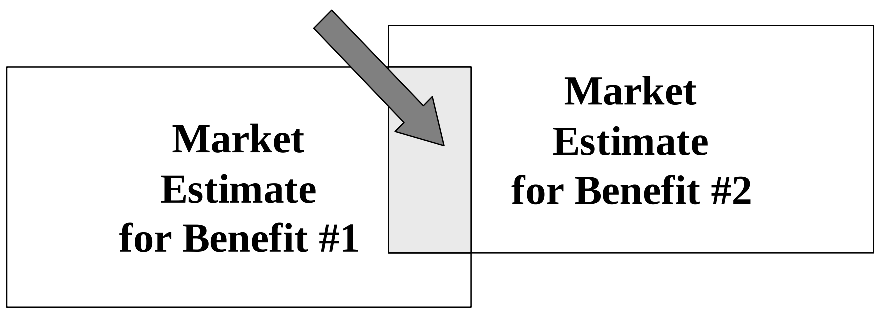

Figure 4. Market Estimation for Combined Benefits: Market Intersection

4. Storage Benefits, Financial Viability and Economic Value

This section discusses the calculation of: 1) financial benefits associated with use of storage for the respective application, 2) financial viability of the storage system, indicated by a benefit to cost ratio (b/c ratio).

4.a. Overview

The primary focus of this section is on estimating financial benefits associated with storage and the financial viability of storage used for a given application or combination of applications.

Specific benefits (increased revenues, reduced costs, or avoided costs) addressed include those for:

Benefit 1.	Bulk Energy Arbitrage -- Cost Reduction or Increased Revenue
Benefit 2.	Central Generation Capacity -- Cost Avoided or Increased Revenue
Benefit 3.	Ancillary Services -- Cost Avoided or Increased Revenue
Benefit 4.	Transmission Support -- Cost Avoided or Increased Revenue
Benefit 5.	Transmission Access -- Cost Avoided or Increased Revenue
Benefit 6.	Transmission Congestion -- Cost or Charges Avoided
Benefit 7.	Deferred Transmission and/or Distribution Upgrade Investment
Benefit 8.	Reduced Time-of-Use Energy Cost
Benefit 9.	Reduced Demand Charges
Benefit 10.	Reduced Reliability-Related Financial Losses
Benefit 11.	Reduced PQ-related Financial Losses
Benefit 12.	Increased Revenue from Renewables Capacity Firming
Benefit 13.	Increased Revenue from Renewable Energy Time-Shift
Benefit 14.	Incidental Energy Benefits

Readers should note that this document does not address cost associated with owning and operating storage systems; the emphasis is on benefits.

Financial Benefit

The financial benefit is the total lifecycle benefit associated with use of a storage plant.

If more than one benefit accrues, then the total benefit is the sum of individual benefits. (Note an important caveat: benefits must indeed be additive given consideration of operational and temporal conflicts, if any.)

Financial Viability – Benefit-to-Cost Ratio

The benefit/cost ratio is calculated by dividing total benefits by the plant cost.

4.b. Financials

The following standard assumption values are used for example calculations in the following subsections. They are used to generalize and to simplify the calculations used as examples.

Financial Life

A plant life of 10 years is assumed for lifecycle financial evaluations (standard assumption value).

Price Escalation

A general price escalation of 2.5% is assumed (standard assumption value). Electric energy and capacity costs and prices are assumed to escalate at that same rate during the storage plant's financial life.

Discount Rate for PV Calculations (Discount Rate)

The standard assumption value for the discount rate is 10%. It is used for making present value calculations to estimate lifecycle benefits.

PV Factor

The following approach was used to simplify present value calculations in examples that follow.

The present value of a given stream of cashflows is a function of the price/cost escalation and the discount rate assumed. From above, for all costs and prices the standard (cost/price) escalation rate is 2.5% per year and the standard discount rate is 10%. A mid-year convention is used.

Based on the foregoing, a "present value factor" (PV Factor) is calculated. That value is used to convert a single/first year value into a present value. Given the standard assumption values of 2.5% standard cost/price escalation rate, 10% for discount rate, and 10 years for storage life the standard assumption value for the PV actor is 7.17.

Consider an example: for an annual/first year benefit of $100/kW-year the lifecycle benefit is:

$100/kW year * 7.17 = $717/kW.

Note that implicit in this approach is the assumption that annual benefits for all 10 years considered are the same as the first year except that the cost or price escalates at 2.5%. If that approach is not appropriate, then an actual cashflow evaluation may be required to estimate the lifecycle benefits, though benefits should not be estimated for more than 10 years.

Annualized Utility Cost Using Fixed Charge Rate

A fixed charge rate is used to convert capital plant installed cost ($/kW) into annual charges that are equivalent to annuity payments. That is, equal payments made during each year of the equipment 's financial life. That annuity equivalent is used to represent the annual carrying charges associated with ownership of capital equipment, in this case storage systems.

The fixed charge rate includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes. The standard assumption value for fixed charge rate is 0.13 for utilities and 0.2 for non-utility owners.

4.c. Calculating Benefits

Benefit #1 Bulk Energy Arbitrage -- Cost Reduction or Increased Revenue

Introduction

Arbitrage involves purchase of inexpensive electricity available during periods when demand for electricity is low, to charge the storage plant, so that the low priced energy can be used or sold at a later time when the price for electricity is high. (Note: in this context “sales” are mostly or entirely to the utility’s end-users, though in more general terms sales could be made via a deregulated wholesale/commodity electricity marketplace.) [27]

To estimate the arbitrage benefit, a dispatch algorithm is used. It has the logic needed to determine when to charge and when to discharge storage, to optimize the financial benefit. Specifically, it determines when to buy and when to sell electric energy, based on price.

Three data items are used in conjunction with the dispatch algorithm. They are:

1. chronological hourly price data for one year (8,760 hours)
2. energy storage round trip efficiency
3. storage system discharge duration

Algorithm for Estimating Annual Benefit from Arbitrage

In simplest terms, the dispatch algorithm evaluates a time series of prices to find all possible “transactions” in a given year that yield a net benefit (i.e., benefit exceeds cost). The algorithm keeps track of net benefits from all such transactions for the entire year to estimate annual arbitrage benefits.

One key point, regarding the approach used for this study, is worth noting: results reflect "perfect knowledge." That is, a predetermined series of projected prices was used. In effect, at any given hour in the year, the algorithm "knows" what prices will be at any other hour of the year.

In reality, of course, the price at a later time is not known. Ideally the dispatch algorithm would be able to partially forecast hourly prices. Such logic is used to forecast electric supply and demand based on such criteria as historical loads, weather, whether a given day is a holiday, weekday or weekend day, and the mix of loads being served.

Note that the algorithm, as described, estimates the annual benefit. A discussion of how to convert that annual value to a lifecycle/present value is described below, in sub-section Arbitrage Lifecycle Benefit below.

Energy Prices

For this document, the chronological hourly price data used were the projected hourly electric energy prices, in California, for 2004. [12] Figure 5. below shows prices for the entire year. Note that there are about 50 hours when the price is above $100/MWh (10¢/kWh). During off peak periods (when storage plants are charged) the price is frequently at about $30/MWh (3¢/kWh).

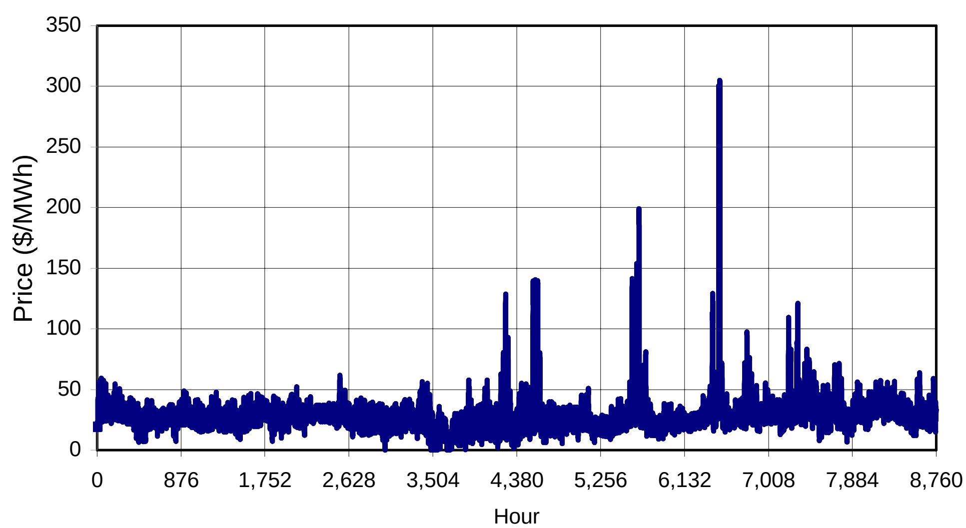

Figure 5. Chronological Electricity Price Data for California, 2004 (projected)

Also evaluated were annual energy prices for the PJM[1] area. Figure 6. below shows prices for the entire year of 2001. Note that there are hundreds of hours when the price is above $100/MWh (10¢/kWh). During off peak periods (when storage plants are charged) the price is frequently at about $30/MWh (3¢/kWh).

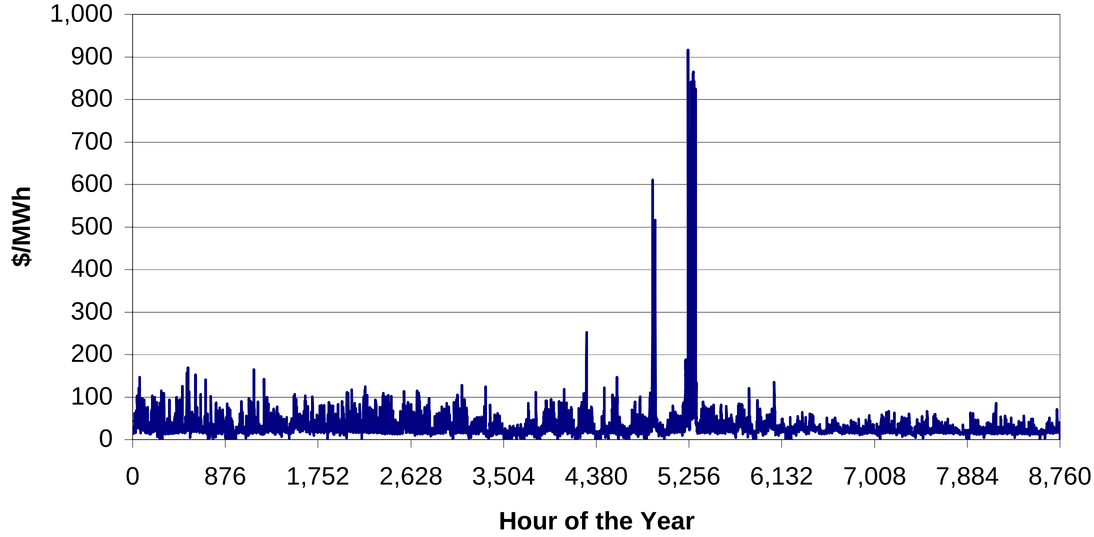

Figure 6. Chronological Electricity Price Data for PJM, 2001

Arbitrage Annual Benefit

As described above, the storage dispatch algorithm is used to estimate the arbitrage benefit for a given year. Estimates are made for storage plants whose discharge duration ranges from 1hour to 10 hours. Figure 7. below shows estimates for storage plants in California whose efficiency is 90% in 2003. Figure 8. shows similar values for the PJM area, for the year 2001, for a 70% efficient storage plant. [21]

As shown in these two figures, as hours of storage discharge duration are added to a storage plant, the incremental and total benefits increase and then begin to level off. That reflects diminishing benefits per buy low – sell high transaction (i.e. the average price differential diminishes as more and more transactions occur during the year.)

Arbitrage Lifecycle Benefit

The values calculated above are for one year of arbitrage benefits. For this document the storage plant is assumed to have a useful life of 10 years. To

[1] PJM Interconnection is a regional transmission organization (RTO) serving all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.

convert the one-year value to present value (PV) the first year benefit is multiplied by the present value factor of 7.17.

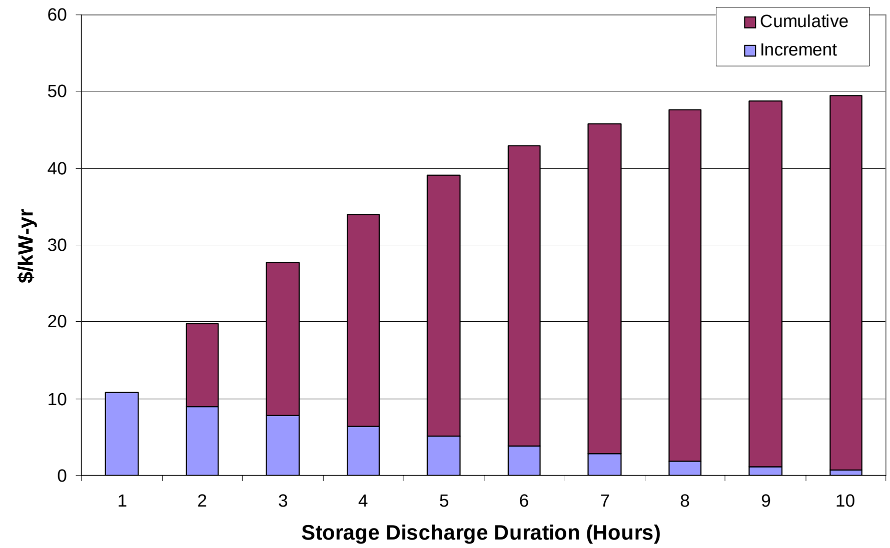

Figure 7. Annual Arbitrage Benefit in California, in 2003, for 90% Efficient Storage, for Discharge Durations Ranging from One Hour to Ten Hours

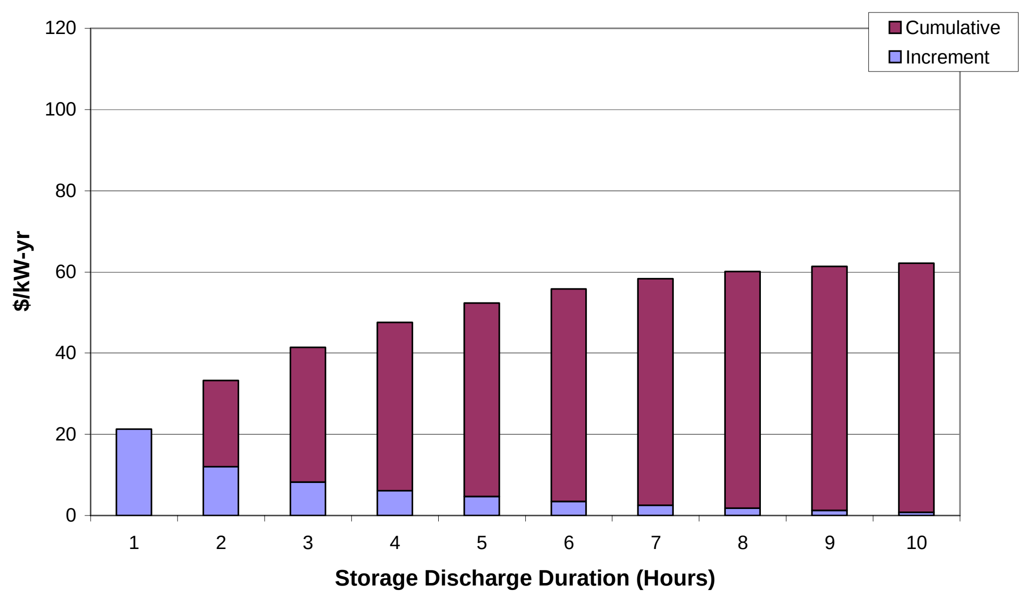

Figure 8. Annual Arbitrage Benefit in PJM Area, in 2001, for 70% Efficient Storage, for Discharge Durations Ranging from One Hour to Ten Hours

Consider an example. From Figure 7. above, for a 90% efficient storage system with four hours of discharge duration the annual benefit is about $34/kW. Multiplying $34/kW-year by the standard assumption value for the PV Factor (7.17) yields a lifecycle PV benefit of $34 * 7.17 = $245/kW.

The lifecycle benefit for storage with discharge durations ranging from one hour to 10 hours are shown in Figure 9. below, for storage plants whose efficiency is 30%, 50%, 70% and 90%.

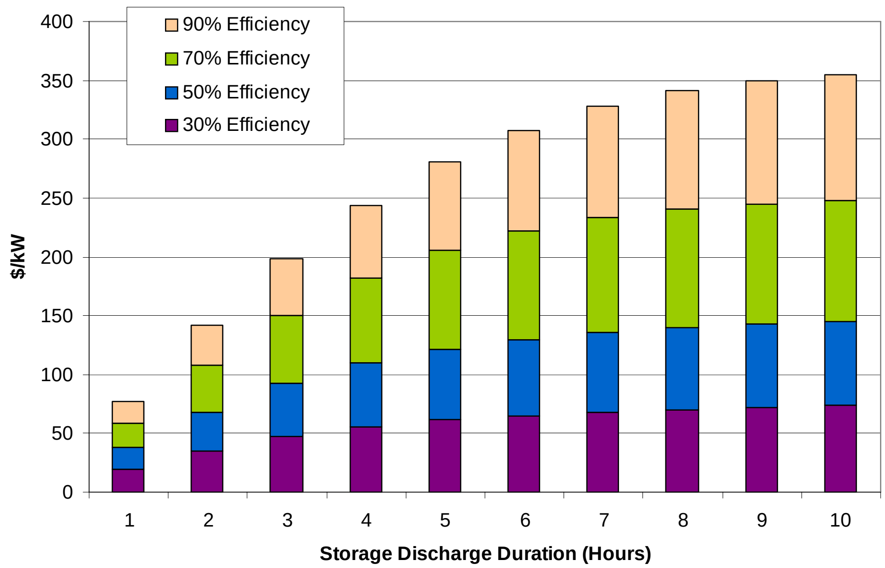

Figure 9. Lifecycle Arbitrage Benefit in California, in 2004, for 30%, 50%, 70% and 90% Efficient Storage, With No Variable Maintenance Cost for Discharge Durations Ranging from One Hour to Ten Hours

To illustrate the concept of converting a one-year arbitrage benefit to a lifecycle, note that the top of the bar (plot) for storage systems with four hours of discharge duration corresponds to lifecycle benefits of about $245/kW. That value is the lifecycle benefit for the storage plant with four hours of discharge duration that is 90% efficient, as shown above.

Arbitrage Net Benefit

The results above do not account for variable costs associated with energy storage. To do that, ideally the dispatch algorithm includes the variable cost in the math/logic used to decide when/if to charge the battery. However, of course variable maintenance for each storage technology and even different configurations of the same technology are different.

Consider a simple example. A kiloWatt-hour of energy costing 3¢/kWh is stored in a 70% efficient storage plant that has a variable maintenance cost of 2¢/kWh of discharge. When discharged the energy is worth 20¢/kWh.

So 20¢/kWh is the gross revenue that accrues to the storage plant owner when the sale is made. However, the energy cost must be subtracted to calculate the net revenue.

First, consider the cost for the charging electricity. In the example the purchase price for electricity to charge the storage plant is 3¢/kWh. If the storage plant is 70% efficient then 30% additional energy must be purchased to make up for the losses. The result is a net charging cost of (3¢/kWh /.7) = 4.3¢/kWh.

When adding consideration of the variable operation cost (2¢/kWh in the example), the net revenue from the example transaction is:

20¢/kWh - 4.3¢/kWh - 2¢/kWh
= 20¢/kWh - 6.3¢/kWh
= 13.7¢/kWh

Figure 10. and Figure 11. below provide lifecycle benefits in California for storage plants whose variable operation cost is 1¢/kWh and 2¢/kWh respectively, in California, for 2003. Figure 12. shows similar values for the PJM area in 2001 [22], for storage whose variable cost is 1¢/kWh.

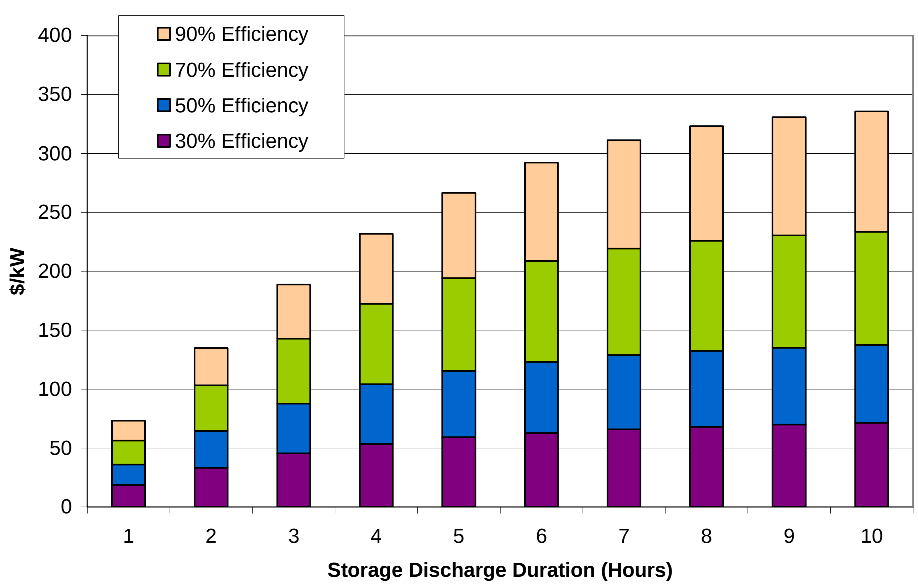

Figure 10. Lifecycle Arbitrage Benefit in California, in 2004, for 30%, 50%, 70% and 90% Efficient Storage, With Variable Maintenance Cost of 1¢/kWh for Discharge Durations Ranging from One Hour to Ten Hours

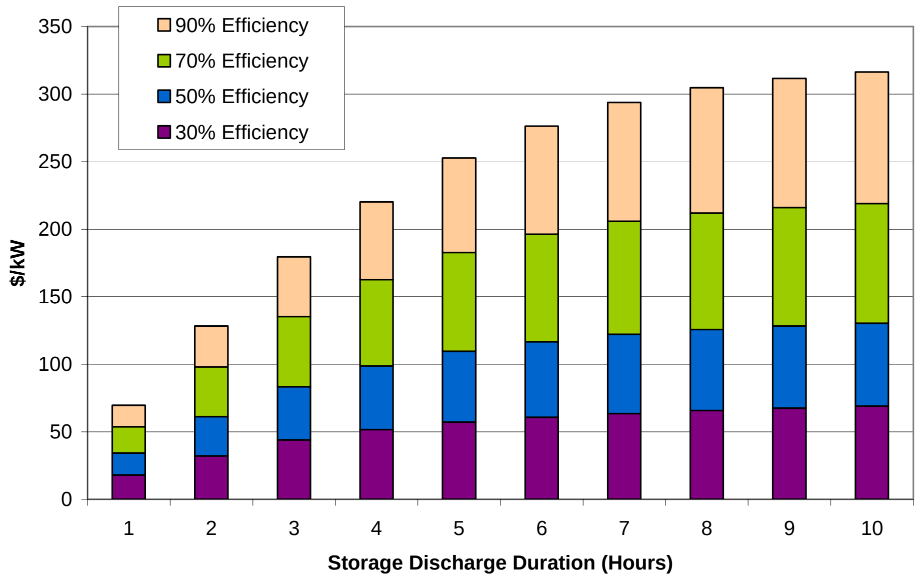

Figure 11. Lifecycle Arbitrage Benefit in California, in 2004, for 30%, 50%, 70% and 90%Efficient Storage, With Variable Maintenance Cost of 2¢/kWh for Discharge Durations Ranging from One Hour to Ten Hours

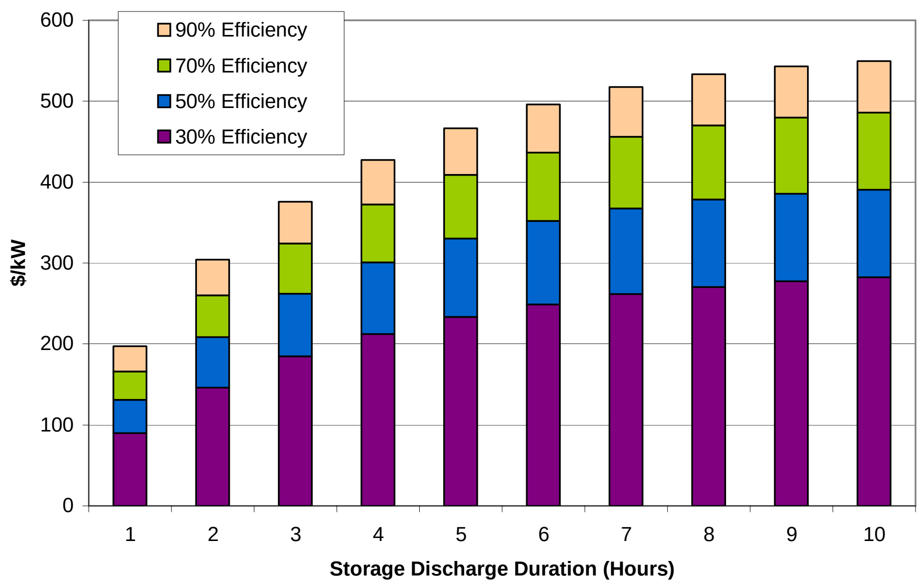

Figure 12. Lifecycle Arbitrage Benefit in PJM Area, in 2001, for 30%, 50%, 70% and 90%Efficient Storage, With Variable Maintenance Cost of 1¢/kWh for Discharge Durations Ranging from One Hour to Ten Hours

Benefit #2 Central Generation Capacity -- Cost Avoided or Increased Revenue

Description

For areas where the supply of electric generation capacity is tight, energy storage could be used to offset the need to: a) purchase and install new generation and/or b) "rent" generation capacity in the wholesale electricity marketplace. If so, then the resulting cost reduction (or avoided cost) is the benefit associated with storage used for this application.

Estimating Central Generation-related Benefits

It is important to note that in many wholesale electricity markets, generation capacity cost is not separated from energy costs. In those regions, the generation capacity cost is embedded in the price per unit of energy purchased. If so, there is no explicit capacity cost or charge that can be avoided nor is there a way to "sell" generation capacity.

For many regions the most likely type of new generation plant "on the margin" is a natural gas fired combined cycle power plant costing about $500/kW. Applying the standard utility fixed charge rate of 0.13 yields an annual cost of 65/kW-year. Applying the PV Factor of 7.17 the lifecycle benefits (for a storage plant used for ten years) are:

$65/kW-year * 7.17
= $466/kW

Arguably this is the maximum possible value. For a storage plant to provide that much benefit they must operate in such a way that the power actually offsets the need for additional generation.

A more conservative (lower-bound) value would be $30/kW-year; representing the cost to own and to operate an older simple cycle turbine-based power plant, probably a used one. [11] (Such plants may have permitting requirements that prohibit them from operating for more than a small number of hours per year.)

Applying the PV Factor of 7.17 the lifecycle benefits (for a storage plant used for ten years) are:

$30/kW-year * 7.17
= $215/kW

Another possibility for ascribing a financial value to this benefit is price-based, where price is set by the electricity marketplace or by a designated agency, probably at the wholesale level. If applicable, electric supply capacity prices could be used to estimate this benefit.

Benefit #3 Ancillary Services -- Cost Avoided or Increased Revenue

Description

It is well known that energy storage can provide several types of ancillary services. In short, these are what might be called support services used to keep the regional grid operating. Two more familiar ones are spinning reserve and load following.

Estimating Ancillary Services-related Benefits

In short, it is difficult to generalize benefits associated with ancillary services; the topic is complex. Ancillary services have several manifestations. Even definitions (of individual ancillary services) vary among entities and regions.

The market for ancillary services is just opening up so there is limited history upon which to draw when trying to peg the benefit. The cost for many ancillary services is very volatile. Some vary over very short time periods. They are often location, time-of-day, and season-specific. For storage, the amount of ancillary benefits that may be realized is affected by discharge duration.

A conservative standard assumption value of $10/kW-year is suggested. [11] [24] That value, though conservative, could add enough extra benefit to make some storage systems cost-effective.

A paper by Tennessee Valley Authority (TVA) reported on actual market prices for ancillary services (regulation and spinning reserve) in the PJM Eastern and New York Independent System Operator (NYISO) Long Island zones during 2000. [24] Prices varied by both time and location; thus the actual value of ancillary services in $/kW-yr will be situation-specific.

Actual values are usually posted by the regional transmission operator (RTO) or Independent System Operator. An example is found at the Midwest RTO. [20] [21]

Applying the 7.17 PV Factor, the lifecycle benefits are an estimated $71.7/kW.

Benefit #4 Transmission Support -- Cost Avoided or Increased Revenue

Description

It is possible that use of energy storage could improve the performance of the T&D system. For any given location, to the extent that energy storage support increases the load carrying capacity of the transmission system, a benefit accrues if:

- additional load carrying capacity defers the need to add more transmission capacity and/or additional T&D equipment

- additional capacity is “rented” to participants in the wholesale electric marketplace (to transmit energy)

Estimating T&D Support-related Benefits

Benefits described above are gross benefits. When evaluating the merits of using energy storage for transmission support the upper bound (of the benefit) is the cost for the standard utility solution. For example, if capacitors are the proposed solution then energy storage offsets the need (and cost) for those capacitors. The “avoided cost” is the resulting benefit from storage for the transmission support application. [6]

The following financial benefit values (listed in Table 7.) are estimated based on related research by the Electric Power Research Institute. [1] [2] That research addresses superconducting magnetic energy storage (SMES) used for T&D support needs in Southern California during hot summer conditions when the need is greatest and when the benefits are highest. Conversely, the estimates are based on conservative assumptions. [2] [6]

Based on these values (derived from references 1, 2, and 6), the standard assumption value for lifecycle benefit from transmission support benefit is $169/kW.

Table 7. T&D Support Financial Benefits—Standard Assumption Values

Benefit Type	Annual Benefit ($/kW-year)	Lifecycle Benefit ($PV/kW)#
Transmission Enhancement	13	96
Voltage Control ($ capital*)	n/a	25
SSR Damping ($ capital*)	n/a	14
Underfrequency load-shedding (per occurrence)	11	34**
	Total	169

Note: all value are for Southern California, assuming hot summer conditions, circumstances for which benefits are highest.

*The benefit is the cost of the most likely alternative (e.g., capacitors), that would have been incurred, if storage was not deployed.

**$11/kW, per occurrence. Assume three occurrences over the (ten year) life of the unit. This value does has not been adjusted to account for time value of money.

#Based on a PV Factor of 7.17 and a ten year life.

Benefit #5 Transmission Access -- Cost Avoided or Increased Revenue

Description

Typically, utilities that do not own transmission facilities must pay the transmission owners for transmission "service." That is, when non-owners use the transmission system to move power to and/or from the wholesale marketplace owners must recoup carrying costs and operations and maintenance cost incurred. Related charges are often called transmission access charges.

Consider municipal electric utilities (munis) and electric cooperatives (co-ops). Munis and co-ops may own some or all of the generation capacity needed.

Almost all munis and co-ops own and operate their electricity distribution system. However, many do not own transmission capacity. And most utilities transmit some power through other utilities' transmission lines. Utilities must pay transmission access charges to transmit power from their own generation plant(s) and/or from the wholesale electricity marketplace.

Estimating Transmission Access-related Benefits

Benefits associated with avoided transmission access charges cannot be generalized. They depend on, among other factors, storage discharge duration, location, time-of-year and time-of-day. Furthermore, in many parts of the country the marketplace for transmission capacity is just emerging.

A standard assumption value of $10/kW-year is suggested as a placeholder. [11] Applying the 7.17 PV Factor, the lifecycle benefits are an estimated $71.7/kW.

Though probably conservative, even that amount might provide enough benefit so that some storage systems (installed primarily for other purposes) may be cost-effective.

As the marketplace for electricity opens up, transmission access charges will be posted for public access. One of the first Regional Transmission Organizations (RTO) to publish such numbers in an easy to use summary form is the Midwest RTO. Monthly and annual transmission access charges that are expected to apply through 2007 for the Midwest RTO are shown in Table 8. [19] [21] Annual values are estimated – for illustration only – by multiplying monthly values by 12.

Benefit #6 Transmission Congestion -- Cost or Charges Avoided

Description

This benefit is transmission congestion charges that are avoided because the energy storage is used. Given the possible shortfall of transmission capacity within and into the state, congestion charges are possible if not likely.

However, as described in the discussion of the transmission congestion relief application, at present this benefit cannot be pegged. The marketplace within which transmission congestion charges will apply is in the formative stages.

Table 8. Low, Average, and High Transmission Access Charges for the Midwest Regional Transmission Organization

	Charge ($/kW-month)		
	Low	Average	High
Annual Average Charge (2003)	0.94	1.39	3.17
Transition Charge (=> 2007)	0.78	0.78	0.78
Total Monthly Charge with Transition Charge	1.72	2.17	3.95

	Annual and Ten-year Cost		
	Low	Average	High
Cost with Transition Charge	Low	Average	High
Annual ($/kW-yr)	20.6	26.0	47.4
Ten-Year NPV ($/kW)	148	187	340

Source: Midwest ISO

Depending on regional approaches, one possible manifestation of congestion charges is time-of-use type pricing for use of the transmission capacity (transmission access charges), rather than being a separate charge.

Estimating Transmission Congestion-related Benefits

Despite the fact that transmission congestion charges are rare, authors contend that they (or transmission access charges that reflect congestion-based pricing) will be increasingly common. A conservative standard assumption value of $10/kW-year is suggested as a placeholder. [11]

Applying the 7.17 PV Factor, the lifecycle benefits are an estimated $71.7/kW.

Though modest, that amount may provide enough benefit so that some storage systems (installed primarily for other purposes) are cost-effective.

Benefit #7 Deferred Transmission and/or Distribution Upgrade Investment

T&D Upgrade Deferral Benefit Overview

The single-year transmission and distribution (T&D) upgrade deferral benefit (deferral benefit) is the financial value associated with deferring a utility T&D upgrade for one year.

The deferral benefit (financial carrying charge) for one year is calculated by multiplying the utility fixed charge rate times the total installed cost for the upgrade.

Consider a simple example: a distribution upgrade of 3 MVA that costs $1.15 million. If the utility fixed charge rate is 0.13, then the single year deferral benefit is 0.13 * $1.15 million or about $150,000.

In other words, if a storage plant can be used such that the $1.15 Million upgrade project can be delayed for one year, the storage plant yields $150,000 in avoided cost for one year (that is, avoided carrying charges, for one year, for the distribution upgrade).

In general terms, locations for which distributed resources are best suited for T&D deferral are those characterized by:

- infrequent and "peaky" maximum load days (i.e., peak load occurs only during a few hours in a day)
- slow load growth
- transmission or distribution upgrades required are "lumpy" (i.e., for one or a few years a small amount of storage can defer a relatively large investment; call it "storage modularity leveraging")
- high transmission access charges (that can be avoided with distributed resources)

Storage Power Output Requirements

To defer an upgrade for one year, it is assumed that the energy storage plant power output is equal to the expected load growth. (Of course that assumption is ideal, in this sense: this approach does not account for uncertainty, primarily: a) load may grow more than expected, or b) the storage may fail on peak demand days.)[2]

Consider the example illustrated in Figure 13. Assume that the distribution node being evaluated is currently rated at 9 MW and that load growth on the circuit occurs at about 2.5% per year.

Furthermore, as shown in the figure, at the end of 2007 loading will equal the distribution equipment's load carrying capacity. During the year 2008 load growth is expected to be 9 MW *0.025 = 225 kW.

[2] Readers should note that units of kW and MW (apparent power) are used herein, rather than the more technically correct true power (kVA and MVA). However, assuming a high power factor, this will not change results much. If necessary, kW and MW values should be adjusted to account for power factor, in any given circumstance.

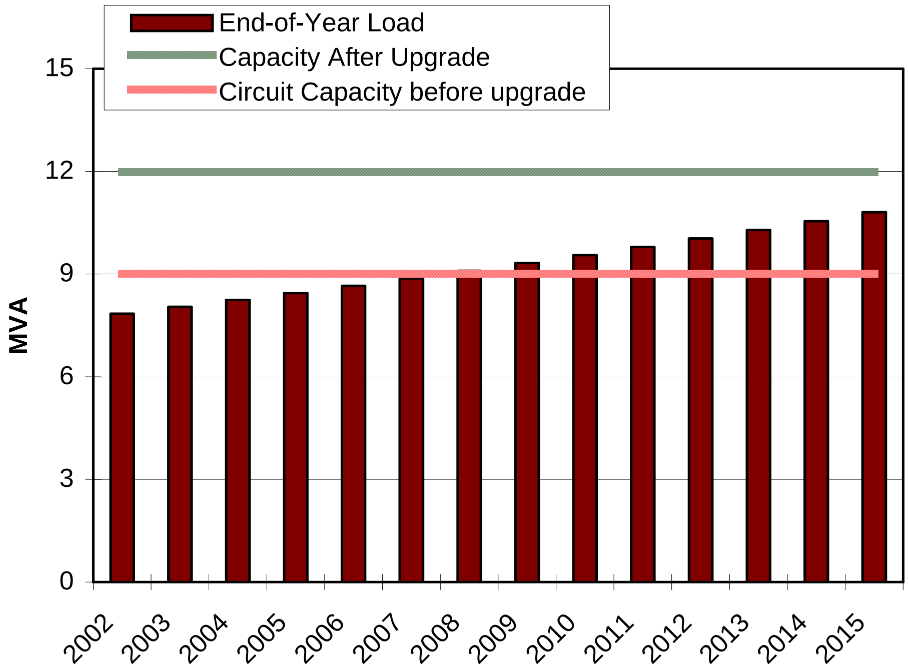

Figure 13. Distribution Peak Load, Capacity, and Upgraded Capacity

In theory, a storage plant rated at 225 kW that can meet load growth in 2007 and thus if deployed at the end of 2006 could allow the utility to defer the distribution upgrade for one year. Of course, an engineering contingency may be in order. That is, it may be that distribution engineers believe that load growth may exceed 225 kW in a given year. If so, storage oversizing may be indicated.

Storage Discharge Duration Requirements

This section is a brief description of one possible process used to estimate the storage discharge duration required for T&D deferral. Discharge duration is the amount of time that the storage plant must be able to discharge at full power.

Ideally, measured demand data for respective cases is used to make the estimate. The hourly load profile for the day with the highest measured demand is isolated from the load data.

The maximum load on that day is treated as if it is the maximum rated (nominal) capacity of the distribution system node being evaluated. When load growth for a single year is added to that day's load, by definition, the top of the modified load profile exceeds the demand ceiling. This is illustrated in the example in Figure 14. in which the upper left chart shows load in "year 0," the year before the distribution capacity is expected to be loaded up to its rating. The lower right chart shows load after one year of load growth. The darker elements of bars for hours 18 and 19 in that day indicate that the load is exceeding the rating of the 9 MVA circuit.

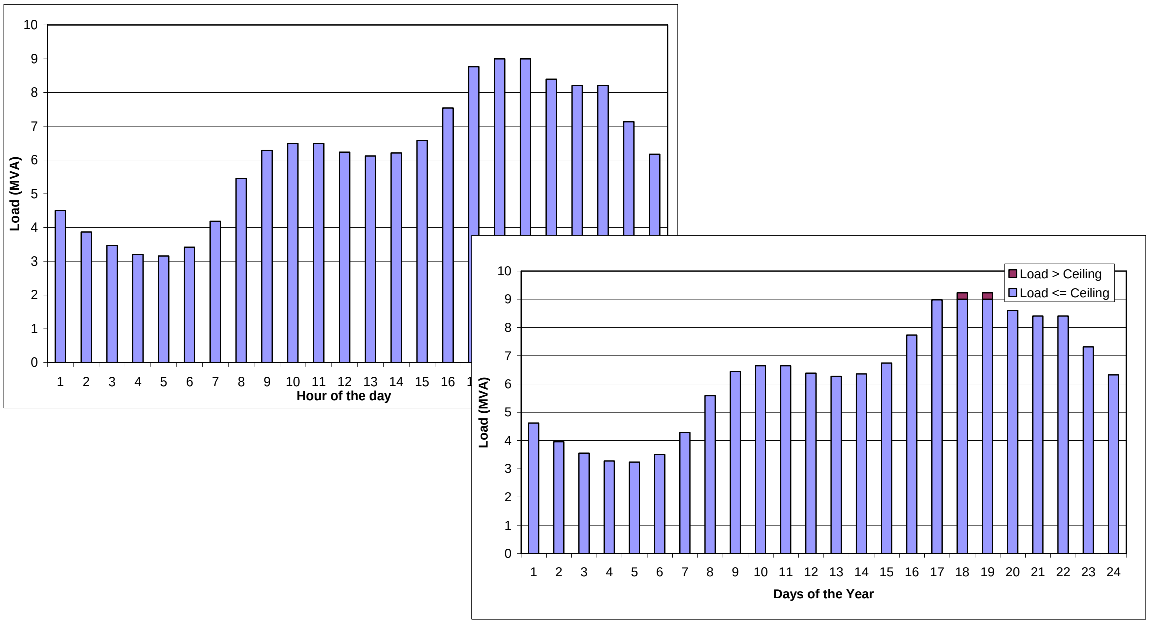

Figure 14. Storage Sizing to Meet Peak Demand:
Energy Requirements for a Single Year's Load Growth

The number of hours during which load exceeds the demand ceiling is the storage duration. Even if the load ceiling is exceeded by just a small margin during a specific hour of the day, an entire hour of "full load" discharge is assumed to be required for the storage plant. This is intended to reflect conservative engineering design.

In the example in Figure 14., 2.5% load growth is added to the "year 0" demand profile. The result is that load, in "year 1" exceeds the demand ceiling on the distribution node for two hours. That is assumed to be the minimum storage duration required, for this example. When addressing engineering contingencies it may be prudent to make the discharge duration longer.

For more details readers are encouraged to refer to a report developed by Sandia National Laboratories entitled *Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral, a Study for the DOE Energy Storage Program*. [28]

Financial Cost for Distribution Upgrades

As a way to generalize benefits associated with storage for T&D deferral, the annual utility benefit is expressed in units of $/kW per year. They represent the annual cost for the utility to own one kW of T&D capacity for one year. (Operating costs avoided are assumed to be negligible.)

A key premise regarding the T&D deferral benefit is that the annual cost for the utility to own the new T&D equipment is the maximum benefit associated with deferring the upgrade for one year.

That annual cost would be incurred by utility customers if the upgrade is made. If another alternative can be used to deliver the same service at lower cost then ratepayers would prefer that lower cost option. (This also assumes that utility stockholders and bondholders are made whole; all dividend, interest, and return of capital payments must be covered by utility revenue requirements.)

Those annual $/kW values (in units of $/kW-year) are derived as follows.

For California, in 50% of locations that will require distribution upgrades in any given year, deferral benefits are $381/kW. [4] [7] To convert that to annualized costs (units of $/kW-year) the utility's fixed charge rate of 0.13 is applied to calculate utility annual revenue requirements (i.e., financial carrying charges.)

Therefore, for a distribution upgrade costing $381/kW installed, the one year carrying charges are 0.13 * $381/kW = approximately $50/kWyear.

For the most expensive locations requiring upgrades (90^{th} percentile and above), cost exceeds about $600/kW. [4] The resulting single year carrying charges are 0.13 * $600/kW = approximately $80/kW-year.

To restate: for distribution upgrades required in a given year, 50% of the upgrades cost about $50/kW-year or more and 10% of all upgrades cost about $80/kW-year or more.

Financial Benefit from Distribution Upgrade Deferral

Before actually describing the financials associated with T&D deferral, readers should note that the description of the process for estimating benefits (below) assumes that the storage plant being considered has the necessary power output and discharge duration as described above.

Given that caveat, consider again the example shown in Figure 13. above. In that example the "upgrade factor" is 0.33 (i.e., 33% more capacity – 3 MVA – will be added to the distribution node when it is upgraded).

Assuming that the storage plant has enough power output and a sufficient discharge duration: a one-year deferral of a 3 MW distribution upgrade, for which the utility's cost to own and to operate is $50/kW-year, is worth:

$50/kW-year * 3,000 $kW_{upgrade}$ = $150,000 for one year.

However, from Figure 14. only 225 kW of storage is required for a one-year deferral. So, in this example, the benefit associated with deferring the 3 MW distribution upgrade by one year, using energy storage is:

$150,000 / 225 $kW_{storage}$ = $666 / $kW_{storage}$.

If the storage will be used in one of the highest cost locations (i.e., where the 90th percentile distribution upgrade cost of $80/kW-year cost prevails), then the single year deferral value for the 3 MW upgrade is:

$80/kW-year * 3,000 $kW_{upgrade}$ = $240,000 for one year.

To defer the 3 MW upgrade costing $80/kW-year storage capacity required is 225 kW. The benefit for a one year deferral of an upgrade costing $80/kW-year is:

$240,000 / 225 $kW_{storage}$ = $1,067 / $kW_{storage}$.

Figure 15. shows a range of deferral values for two utilities in the PJM area. Those deferral values are added to arbitrage benefits for PJM. From that figure, a 70% efficient storage plant with three hours of discharge duration, providing one year of deferral on a distribution system upgrade with a somewhat typical cost provides about $700/kW of benefits (PV) over 10 years. In a high cost location the storage plant provides $1,200/kW of benefit (PV) over 10 years. This assumes that the storage plant is correctly sized. [22]

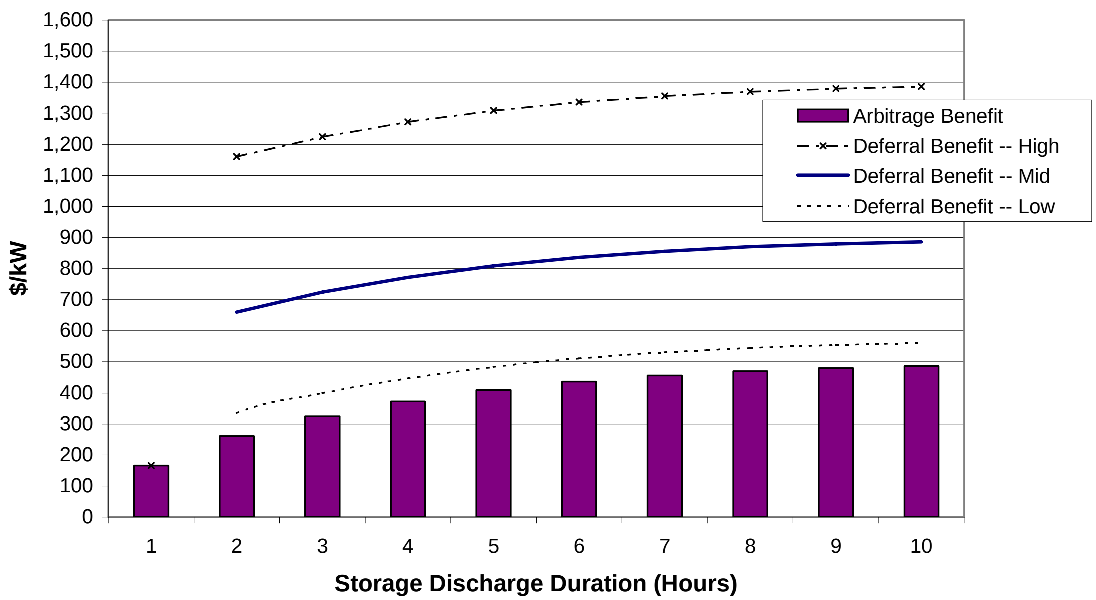

Figure 15. Total Net Benefit, 70% Efficient Storage Operated for Ten Years

Financial Benefit from Transmission Upgrade Deferral

Estimating benefits of deferring transmission upgrades is the same as the process used to estimate distribution system benefits. In California, there is one significant transmission project that might be deferrable. It is a high-voltage line connecting the Northern California and Southern California transmission systems, referred to as Path 15. The existing load carrying capacity is about 3,900 MW and the upgrade has an estimated cost of about $500 million. [13]

Assuming a load growth rate of 2.5%/year, the additional load to be carried in year 1 of the line's existence would be 3,900 MW * 2.5% = about 100 MW. So, in theory a 100 MW storage plant could be used to serve load growth in year 1 and thus could be used to defer the 3,900 MW project for one year. [13]

Using the 0.13 standard assumption value for fixed charge rate, the single year deferral benefit = $65 million.

The single year benefit associated with use of storage to defer the transmission project is \$65 million/100 $MW_{storage}$ = \$650/$kW_{storage}$.

Multi-Year Deferrals

It is important to note, again, that for this study storage capacity added in a specific year to defer an upgrade is credited with the deferral in that year <u>only</u>.

If storage is used to defer an upgrade in subsequent years, the same evaluation described above (estimating storage capacity requirements, single year storage deferral benefit, and storage discharge duration) is undertaken "on the margin" to determine whether the next year of deferral is cost-effective.

Readers should note that if storage *is* used to defer a specific upgrade for more than one year, storage that was added in previous years must remain in place. That is, storage capacity used for deferral in subsequent years is <u>added to the existing storage capacity</u>, with additions sized to keep pace with load growth.

It is safe to assume that in most cases, at some point in time, the T&D upgrade will take place. If so, the storage can remain in place (for arbitrage) or it could be moved to another location for additional capacity benefits, as described in the next section.

Storage Redeployment and Portability

One way that a given storage plant could provide multiple years of distribution capacity upgrade deferral benefit involves moving the storage from one T&D hot spot to another. This, of course, requires that the storage system can be disconnected, moved, and reconnected, with modest effort and cost.

Even if a storage system is moved and re-used once during the life of the storage plant, the effect on storage's cost effectiveness can be dramatic. In the example above, storage provides a one year deferral benefit of $666/kW of storage. So storage used for two similar situations, in different years could provide benefits of $666/kW in year 1 and another $666/kW in the future year. (Of course the benefits accruing in future years must be discounted to adjust for the time value of money before being summed.)

Though less likely, storage could also be used to address different winter and summer hot spots, in the same year.

Benefit #8 Reduced Time-of-Use Energy Cost

Description

To reduce electricity end-users' time-of-use (TOU) energy cost, energy storage is charged with low-priced energy (typically during off-peak periods) so the energy can be used (discharged) when energy price is high (typically during on-peak periods). The overall reduction in cost for electric energy is the benefit associated with use of storage.

This benefit applies to commercial and industrial electricity end-users that qualify for TOU energy prices; those are specified in the applicable utility tariff.

Typically, TOU energy prices vary by time of day, day of the week, and season of the year. There may be two or more price points specified. One purpose for TOU rates is to give customers an incentive to use energy during off-peak periods rather than on-peak, thereby reducing peak demand on the utility supply system.

To the extent a customer must use energy on-peak, storage can help to mitigate those costs.

The standard assumption value for this benefit is calculated based on PG&E's A-6 Small General Time-of-Use Service tariff. Commercial and industrial (C&I) electricity end-users whose power requirements are less than or equal to 500 kW are eligible for the A6 tariff.

Figure 16. shows the prevailing energy price relative to the hour of the day for the A-6 tariff, for the summer billing period of May to October.

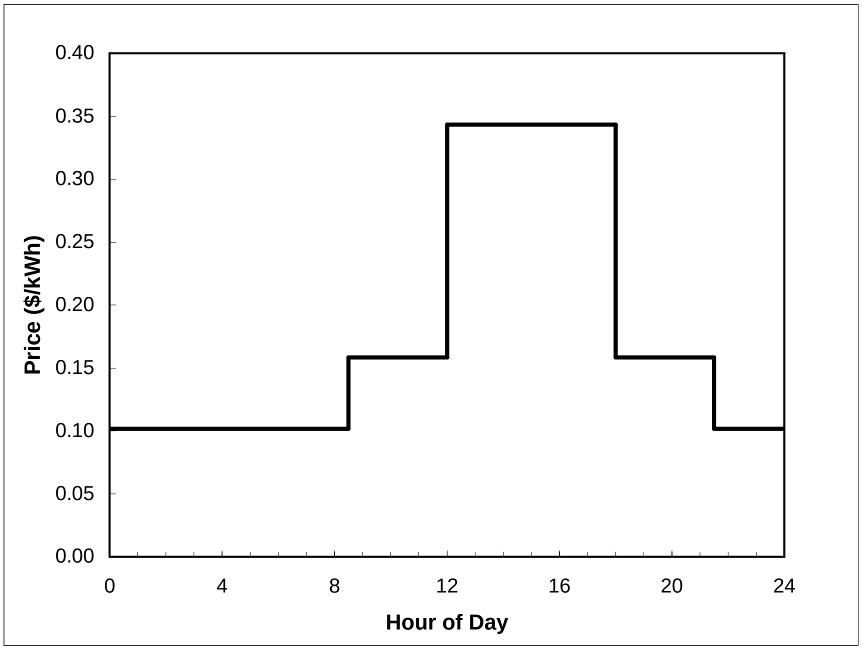

Figure 16. Time-specific Price for Electricity – A6 Tariff, Summer

Time-of-use electricity prices are:

Period	Time-of-day	Price
Partial-peak	8:30 am to 12:00 pm	15¢/kWh
On-peak	12:00 noon to 6:00 pm	32¢/kWh
Partial-peak	6:00 pm to 9:30 pm	15¢/kWh
Off-peak	9:30 pm to 8:30 am	10¢/kWh

(During the winter months (November to April) there are only partial peak (8:30 am to 9:30 pm) and off-peak (9:30 pm to 8:30 am) periods specified).

Estimating Reduced Time-of-Use Energy Cost

There are 720 hours per year during which the on-peak energy price applies. A storage plant whose discharge duration is six hours would allow the end-user to avoid annual on-peak energy charges of:

32¢/kWh * 720 hours/year
= $.32/kWh * 720 hours/year
= $230/kW-year

For an 80% efficient energy storage system, the cost to charge the storage plant (for 720 hours of discharge) using low-priced, off-peak energy priced at 10¢/kWh is:

10¢/kWh * (720 hours/year ÷ 80% efficiency)
= $.10/kWh * 900 hours/year
= $90/kW-year

The cost reduction realized is:

$230/kW-year - $90/kW-year
= $140/kW-year

To express that annual benefit in units of $/kW, the annual cost is multiplied by 7.17:

$140/kW-year * 7.17
=$1,004/kW

Note that the storage plant could have a discharge duration that is less than the duration of the on-peak price period. If, for example, a two hour storage plant is used then the annual benefit is:

2 hours/6 hours * $140/kW-year
= 0.33 * $140/kW-year
= $46.2/kW-year

The storage duration selected depends on the cost of additional energy storage versus the incremental benefit.

Note also that the benefit estimation illustrated above does not account for variable maintenance cost incurred as the storage plant is used (including overhauls and subsystem replacement, as applicable).

Benefit #9 Reduced Demand Charges

Description

Reduced demand charges are possible when energy storage is used to reduce an electricity end-user's use of the electric grid during times when demand on the grid is high (i.e., during peak electric demand periods).

To reduce demand charges, energy storage is charged with low priced energy so the energy can be used (discharged) when demand charges apply. The overall reduction in cost due to demand charges is the benefit associated with use of storage.

This benefit applies to commercial and industrial electricity end-users that qualify for electric utility tariffs that include demand charges.

Estimating Reduced Demand Charges

Typically, demand charges apply during afternoon and evening hours of the day, during late Spring to late Autumn. There may be two or more demand charge levels that apply during different parts of the day or year.

The standard assumption value for this benefit is calculated based on PG&E's E-19 Medium General Demand-Metered TOU Service tariff. It applies to commercial and industrial end-users with peak demand that exceeds 500 kW.

Figure 17. below shows diurnal demand (on the grid) with and without storage used to reduce demand charges, for an industrial facility with a constant electric load of 1 MW. The dashed line indicates that the storage plant serves all load for the six hours during which demand charges apply and that the storage plant charges for 7.5 hours at night when demand charges do not apply.

It is very important to note that demand charges are applied rigorously, on a monthly basis. The implications are that if the storage system should fail to serve load at any time during the month when demand charges apply, then demand charges are assessed for the entire month. That is an important consideration when making design tradeoffs between storage system cost and reliability.

The E-19 tariff assesses $13.35 per kW per month on-peak, and $3.70 per kW per month ($/kW-month) during partial-peak periods (time periods are the same as described above for the PG&E A-6 tariff). In addition, customers are charged $2.55/kW-month for the maximum demand, regardless of when it occurs. (In effect, if a customer's maximum demand occurs during the period when peak demand charges apply, then the on-peak peak demand is added to the "any time" charge.)

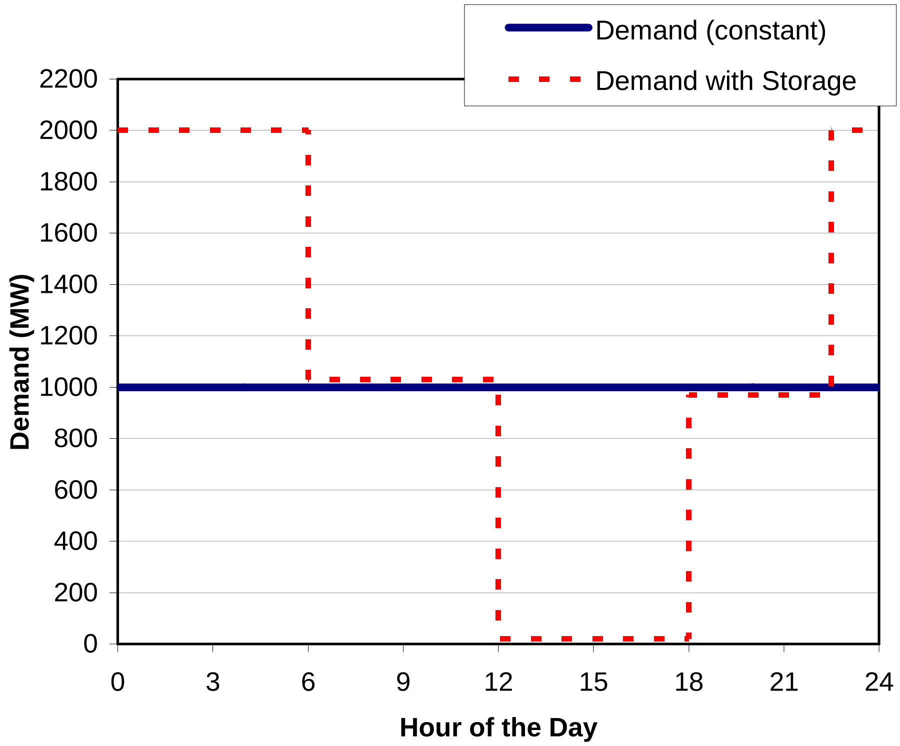

Figure 17. Constant Demand and Demand with Storage Used to Reduce Demand Charges

Assuming a storage system will discharge every hour in a given month during which the on-peak demand charges apply, the customer saves \$13.35/kW-month. However, as shown in Figure 17. above, load is added at night (for storage charging). So an additional \$2.55/kW-month "any time" demand charge is incurred by the customer.

The total demand charge reduction (benefit) is:

\$13.35/kW-month – \$2.55 = \$10.80/kW-month

That benefit applies for six months per year, for a total annual benefit of:

\$64.8/kW-year

Lifecycle benefits are calculated by applying the PV Factor of 7.17 so the annual value translates to a lifecycle benefit of \$465/kW-year.

The total monthly partial peak demand charge reduction (benefit) is:

\$3.70/kW-month – \$2.55 = \$1.2/kW-month

That monthly benefit applies for six months per year, for a total annual benefit of:

$1.2/kW-month * 6 months/year = $6.9/kW-year

For a ten year life, the present value is:

7.17 * $6.9/kW-year = $49.5/kW

Of course, there are also energy implications of this operation. Most utility rate structures that include demand charges also have time-of-use energy prices, but some do not. The PG&E E-19 tariff is an example (as shown below).

Tariffs that include a demand charge and that use a constant/single energy price (for all hours of the year) tend to be less favorable for storage.

The rate structure used for this example – PG&E's E19 Tariff – has time-specific energy prices of:

Period	Time-of-day	Price
Partial-peak	8:30 am to 12:00 noon	11¢/kWh
On-peak	12:00 pm to 6:00 pm	19¢/kWh
Partial-peak	6:00 pm to 9:30 pm	11¢/kWh
Off-peak	9:30 pm to 8:30 am	9¢/kWh

There are 720 hours per year during which the on-peak energy price applies. A storage plant whose discharge duration is six hours would allow the end-user to avoid annual on-peak energy charges of:

19¢/kWh * 720 hours/year
= $.19/kWh * 720 hours/year
= $137/kW-year

For an 80% efficient energy storage system the cost to charge the storage plant (for 720 hours of discharge) using low-priced, off-peak energy priced at 9¢/kWh is:

9¢/kWh * (720 hours/year ÷ 80% efficiency)
= $.09/kWh * 900 hours/year
= $81/kW-year

The energy cost reduction realized is:

$137/kW-year - $81/kW-year
= $56/kW-year

To express that annual benefit in units of $/kW the annual cost is multiplied by 7.17. The lifecycle energy-related cost reduction is:

$56/kW-year * 7.17
= $401/kW

When adding the benefits associated with demand charge reduction and with incidental energy cost the total lifecycle cost is:

$465/kW + $401/kW
= $866/kW

Note: those benefits do not account for variable maintenance costs incurred as the storage plant is used (including overhauls and subsystem replacement, as applicable). Those are included in the estimate of the total lifecycle cost.

Benefit #10 Reduced Reliability-related Financial Losses

Description

In simplest terms, benefits associated with improved electric service reliability accrue if storage reduces financial losses associated with power outages. This benefit is very end-user-specific and applies to commercial and industrial (C&I) customers, primarily those for which power outages cause moderate to significant losses.

The two possible approaches described below yield benefits that are generic. If a credible rationale can be provided for more specific reliability benefits (e.g., for a specific type of end-user) then the approaches below may not apply.

Estimating End-user Reliability Benefit – Value-of-Service Approach

For the value-of-service approach, the benefit associated with increased electric service reliability is estimated using two criteria: 1) annual outage hours – the number of hours per year during which outages occur, and 2) the value of “unserved energy” or value-of-service (VOS); units are $/kWh.

The standard assumption value for annual outage hours is 2.5 hours per year. A value-of-service of $20/kWh is recommended as a placeholder.[16]

To calculate the annual reliability benefit, the standard assumption value for annual outage hours is multiplied by the VOS:

$20/kWh * 2.5 hours per year
= $50/kW-year.

To calculate lifecycle benefits over ten years, the annual reliability benefit of $50/kW-year is multiplied by the PV Factor of 7.17. Lifecycle benefits are:

$50/kW-year * 7.17
= $359/kW

Estimating End-user Reliability Benefit – The "Per Event" Approach

Reliability benefits may be estimated by ascribing a monetary cost to losses associated with power system "events" lasting one minute or more and that cause electric loads to go off-line.[8] Reliability events considered are those whose effects can be avoided if storage is used.

Based on a survey of existing research and known data related to electric service reliability, a generic value of $10 per event for each kW of end-user peak load has been chosen. [8] [9]

The standard assumption value for the annual number of events is five. [8] The result is that storage used in such a way that the end-user can avoid five electric reliability events, each worth $10 for each kW of end-user peak load yields an annual value of $50/kW-year. [8]

Finally, multiplying by the PV Factor of 7.17 yields a lifecycle benefit of $359/kW.

For additional information about financial considerations related to utility service reliability please refer to a report produced by Lawrence Berkeley National Laboratory entitled: *Evaluating the Cost of Power Interruptions and Power Quality to U.S. Electricity Consumers*.[29]

Benefit #11 Reduced Power Quality-related Financial Losses

Description

This benefit is very end-user-specific and is difficult to generalize. It applies primarily to C&I customers, primarily those for whom power outages cause moderate to significant losses.

Specific types of poor power quality are well documented. Technical details are not covered in depth here, although they are summarized in Section 2 in the subsection describing the power quality (PQ) application. [25]

In the most general terms, PQ-related financial benefits accrue if energy storage reduces financial losses associated with power quality anomalies. Power quality anomalies of interest are those that cause loads to go off-line and/or that damage electricity-using equipment and whose negative effects can be avoided if storage is used.

As an upper bound, the PQ benefit cannot exceed the cost to add the "conventional" solution. For example: if the annual PQ benefit (avoided financial loss) associated with an energy storage system is $100/kW-year and basic power conditioning equipment costing $30/kW-year would solve the same problem if installed, then the maximum benefit that could be ascribed to the energy storage plant for improved PQ is $30/kW-year.

Estimating Reduced PQ-related Financial Losses

PQ-related benefits may be estimated by assigning a monetary cost to losses associated with PQ "events" lasting less than one minute and that cause electric loads to go off-line. [8] PQ events considered are those whose effects can be avoided if storage is used.

Based on a survey of existing research and known data related to PQ, a generic value of $5/event for each kW of end-user peak load is the standard assumption value for this document. Based on that same information, the standard assumption value for the annual number of events is 20. [8] [9]

The result is that storage used in such a way that the commercial or industrial electricity end-user can avoid 20 power quality events per year, each worth $5 per kW of end-user peak load, providing an annual benefit of $100/kW-year.

After multiplying by the PV Factor of 7.17, the lifecycle benefit is $717/kW. Implicit in that approach is the assumption that the PQ benefit is the same (in real dollar terms) for each of ten years.

For additional coverage of this topic please refer to a report developed by Lawrence Berkeley National Laboratory entitled: *Evaluating the Cost of Power Interruptions and Power Quality to U.S. Electricity Consumers*.[29]

Benefit #12 Increased Revenue from Renewables Capacity Firming

Description

Intermittent generation sources – including renewables – can produce electric energy reliably and in the case of wind, at a cost that competes with conventional generation. However, because intermittent renewables cannot be counted on to serve load when needed, often there is a need to provide for "firm" generation (generation that is "dispatchable") to augment the renewables.

Storage could be used to time-shift electric energy generated by renewables. Energy is stored when demand and price for power are low, so the energy can be used when a) demand and price for power is high, and b) output from the intermittent renewable generation is low.

If that is done, then the renewables-storage system would be able to provide firm power when needed, using renewable energy. Note that, in many cases "peaking" generation need only provide power for 50 to 200 hours per year or less; during times when demand for power is highest.

Estimating Revenue from Grid-connected Renewables' Capacity Firming

The additional (incremental) revenues that accrue (or cost that can be avoided) because storage is used (in conjunction with wind generation) is the financial benefit associated with renewables capacity firming.

Readers should note that the calculation below assumes that the storage plant used to firm up the wind generation plant's output has the same nameplate rating as the wind generator.

The upper bound benefit for dispatchable generation capacity would be the annual carrying cost for a new combined cycle power plant on the margin. The standard assumption value for the annual benefit is $65/kW-year. If additional capacity will come from older or refurbished power plants, especially peaking power plants, then the benefit for generation capacity may be as low as $30/kW-year. (Of course, if a region has more generation capacity than needed then adding storage to wind generation may be worth little or nothing.)

However, renewables normally generate electricity at some level during peak demand periods when utilities need peaking capacity. As a rule, solar energy tends to provide a "full load equivalent" output of 80% of its nameplate rating during peak demand periods.

The implication is that capacity firming for solar energy plants provides only 20% of the total capacity value. If a combined cycle plant is on the margin (is the next plant planned) for the electric supply system, then firming solar generation capacity provides 20% * $65/kW-year = $19.5/kW-year. If the lower cost peaking resource described above is on the margin then the benefit is 20% * $30/kW-year = $6/kW-year.

Wind generation's correlation with peak demand tends to be much lower than that for solar generation: the standard assumption value is 0.3 (30%).

[Note: This value is used primarily for illustration and it may be generous in many circumstances. Though it may apply in windier regions such as the Midwest, Independent System Operators (ISOs) are just beginning to establish such a value. For example, PJM Interconnection LLC recently set this value at 20%. [18] (PJM is the grid system operator for a region that includes parts of seven states and the District of Columbia in the Central Atlantic Coast region of the U.S.) The PJM website address is http://www.pjm.com.

Therefore, capacity firming can provide benefits equal to 100% minus 30%, or 70% of the full cost of the capacity source that is on the margin. If capacity on the margin is a combined cycle plant, then the capacity firming benefit is 70% * $65/kW-year = $45.5/kW-year. For the lower cost peaker power plant on the margin, the benefit is 70% * $30/kW-year = $21/kW-year.

As with other single year benefits, values expressed in units of $/kW-year are converted to lifecycle costs by multiplying by 7.17. Readers should note that capacity needs – megawatts (MW) – vary from year to year; the type of capacity that is on the margin and the prevailing market price, if any, likewise vary.

Benefit #13 Increased Revenue from Renewable Energy Time-shift

Description

Intermittent generation sources – including renewables – produce much of their electric energy when that electricity has low value (i.e., when energy use is low and/or when there is already enough generation on-line.)

Energy storage could be used to time-shift energy production from times when the value of the energy is low, such that the energy can be used when
a) demand for power is high, and b) storage owners can sell the energy for a large premium.

This benefit is distinct from that for renewables capacity firming: capacity firming is done to avoid the need for generation equipment (MW) whereas the benefit associated with the renewables energy time-shift is related to reduced fuel use during peak demand periods for central generation plants.

Estimating Renewable Energy Time-shift Benefits

The following estimation approach is for a storage plant whose nameplate output is equal to the wind generation plant's output. The storage plant operation is like load-following in reverse: the storage plant "fills in" during peak demand periods such that a constant level of power is provided. At some times the storage is providing most of the energy, and at other times the storage provides a small portion of the energy.

Standard assumption values for energy prices for this benefit are based on the time-specific prices paid under terms of some existing Standard Offers in California. The period of performance for these standard offers is about 10 remaining years, in most cases.

Time-specific prices of interest are those that apply during weekdays for four summer months (June through September), for a total 87 weekdays per year.

They are:

Period	**Time-of-day**	**Price**
Mid-peak	8:00 am to 12:00 noon	8.6¢/kWh
On-peak	12:00 pm to 6:00 pm	33.3¢/kWh
Mid-peak	6:00 pm to 11:00 pm	8.6¢/kWh
Off-peak	11:00 pm to 8:00 am	4.6¢/kWh

The actual benefit (associated with adding storage) is the difference between what the energy would be worth if not time-shifted versus benefits accruing if storage is used.

Two factors are worth noting:

- 30% of wind generation (energy output) occurs during the on-peak price period – wind generation's on-peak energy price correlation.
- The average prevailing price during "non-peak" price periods (i.e., during off-peak and mid-peak price periods) is an average of 6.6¢/kWh (the average of 8.6¢/kWh and 4.6¢/kWh for nine hours each). That is the benefit for the wind generation produced during non-peak times if that energy is sold as it is generated.

The generalized benefit calculation methodology for this benefit begins with an estimate of the marginal revenues associated with adding storage to wind generation.

First, the number of hours per day (during peak price periods) that the storage must discharge is calculated, as follows. Assuming that the storage plus wind generation system will provide power for six hours per day (during which the high price prevails) and using the on-peak energy price correlation of 30%, the number of hours of "time-shift" is:

6 hours per day * (1- 30%)
= 4.2 hours per day

From above, there are 87 weekdays per year during which this occurs. The annual hours are:

87 days per year * 4.2 hours per day
= 365 hours per year

The gross revenue is:

33.3¢/kWh * 365 hours per year
= $121.5/kW-year

Applying the PV Factor of 7.17 the lifecycle revenues are:

$121.5/kW-year * 7.17
=$871/kW

Finally, the benefit that would have accrued if the energy used to charge the energy storage was sold real-time to the grid. From above, the average price for that energy is 6.6¢/kWh. For an 80% efficient storage plant to discharge for 365 hours per year, it must charge for 365÷0.8 = 456 hours per year.

If that energy is sold real-time (rather than using it to charge storage), it would provide revenues of:

6.6¢/kWh * 456 hours per year
= $30.1/kW-year

Lifecycle revenues would be:

$30.1/kW-year * 7.17
=$216/kW

The lifecycle benefit associated with adding storage is:

$871/kW - 216/kW
=$655/kW

Note that the foregoing discussion of benefits does not account for related variable costs for storing electricity. Those must be addressed in estimates of storage lifecycle cost.

Benefit #14 Incidental Energy Benefits

This section describes calculations used to estimate the benefit for energy discharged from storage, for capacity-related applications (e.g., T&D deferral, demand charge reduction, transmission support, etc.).

For this document, when energy storage is used for capacity-related applications, any financial benefit associated with the energy discharged is referred to as being "incidental" to the overall benefit.

The amount of incidental energy discharged and the associated benefit are very application and situation-specific.

Perhaps the most extreme example is energy storage used for T&D support. Assuming total discharge duration of five seconds, the storage plant may discharge for less than an hour, total, in a year; though it may provide significant capacity benefit. (The plant would discharge less than 1 kWh of energy, per year, per kW of storage plant rated output.)

In that case it is not worth calculating the benefit. However, if storage is used in such a way that it discharges during the times when energy price is high then it may be worth estimating the incidental energy benefit.

Grid-price-based

Figure 18. plots the relationship between the running average of the prevailing price for wholesale electric energy (shown on the Y axis) for the 1,000 highest load hours during the year, in California. [3]

Consider an example. A storage plant with two hours of discharge duration, used for T&D deferral, discharges for 20 hours per year (two hours, ten times per year).

If the storage happens to discharge during the 20 hours when forecasted energy prices are highest then the average price (benefit) is $180/MWh, or 18¢/kWh.

At 18¢/kWh for 20 hours per year the annual benefit is:

$0.18/kWh * 20 hours per year
= $3.6/kW-year

The lifecycle benefit is:

$3.6/kW-year * 7.17
= $26/kW

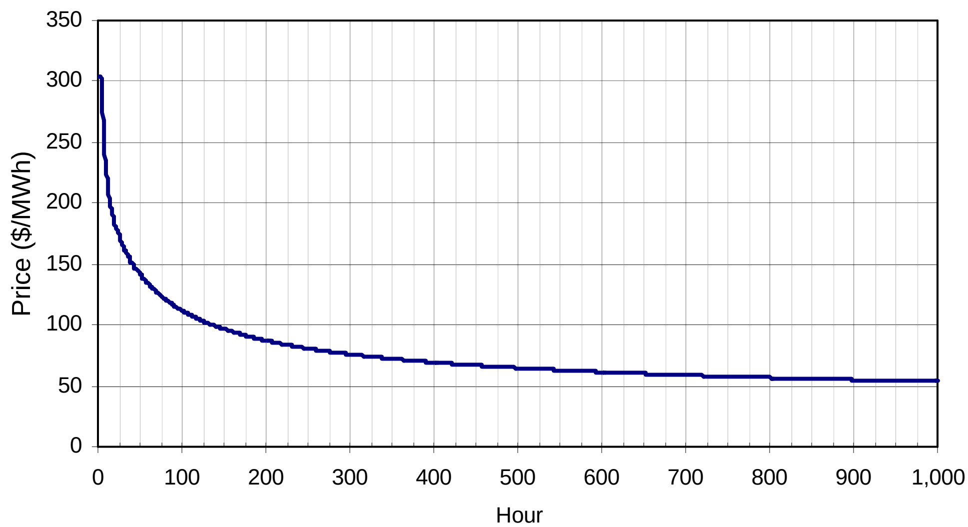

Figure 18. Running Average Energy Price ($2003), 1,000 Hours

Tariff-based

If incidental energy is provided by a storage system used for an end-user application, especially for demand reduction, then the benefit is based on the variable charge/price for electric energy specified in the applicable utility tariff.

Regarding incidental energy value for demand charge reduction: the tariff that provides for the demand charge (units are $/kW-month) also specifies the energy-related charges. For example, the PG&E E-19 tariff (used to illustrate calculation of the demand charge benefit) specifies an on-peak summer energy price of 19¢/kWh.

From the report subsection titled Benefit #9 Reduced Demand Charges above, the incidental energy provides benefits of $56/kW-year and $401/kW lifecycle.

5. Combining Benefits

5.a. Introduction

In many cases more than one benefit is required from storage for benefits to exceed cost. However, careful consideration of operational, technical, and market details is required before benefits may be added.

Operational Conflicts

Operational conflicts involve competing needs for a storage plant's power output and stored energy. For example, storage providing power in lieu of a distribution upgrade deferral cannot be called upon to provide transmission congestion relief as well. Storage providing T&D support may not be capable of providing either enough power or power that is stable enough to serve the central generation capacity application.

Consequently, when estimating combined benefits it is important that the reader not add benefits from applications with conflicting operational needs.

Technical Conflicts

In some cases storage systems are physically unable to serve more than one need. One example is storage that cannot tolerate numerous deep discharges and/or significant cycling. These storage systems might be well suited to the T&D deferral application though they are not suitable for energy price arbitrage.

Another example is storage that cannot respond very rapidly to changing line conditions. Such systems may be suitable for energy arbitrage or to reduce demand charges but may not be able to provide transmission support or end-user PQ benefits.

Consider also storage system reliability. Less reliable (though lower cost) storage systems may be suitable for pursuit of energy arbitrage or time-of-use energy cost reduction benefits; however, such systems could not be used for demand reduction, T&D support, or T&D deferral benefits.

Market Intersections

As described in Section 4 and as illustrated in Figure 19., it is important to consider how combining benefits may affect (reduce) the maximum market estimates.

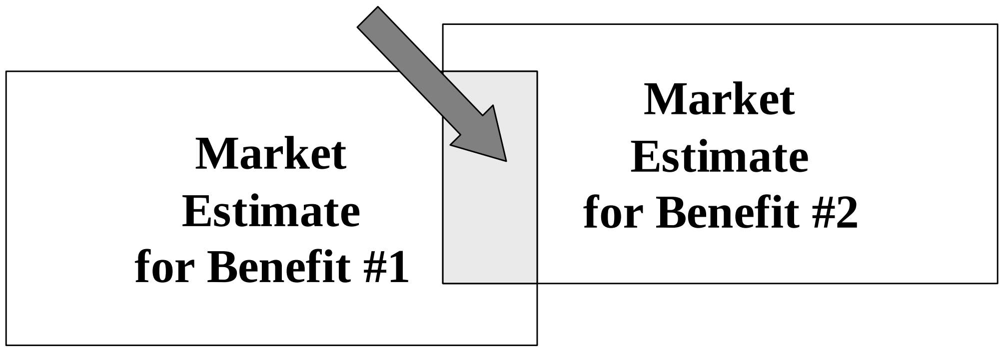

Figure 19. Market Estimation for Combined Applications/Benefits: Market Intersection

Consider an example: end-users will use energy storage for demand charge reduction, reliability enhancement, and improved power quality. Market estimates would account for the following:

- Technical market potential encompasses all commercial and industrial electricity end-users.
- However, only a portion of those end-users pay demand charges.
- For most commercial and industrial electricity end-users that pay demand charges, increased electric reliability is not a compelling issue.
- Only a portion of customers that pay demand charges and that are concerned with electric reliability will derive a financial benefit from improved power quality.

5.b. Energy Arbitrage Plus T&D Deferral

Perhaps the most compatible combination of applications is T&D deferral and energy arbitrage. In many, and perhaps most cases, localized T&D peak demand is coincident with “system” (supply and transmission) peak demand periods. The implication is that energy discharged for T&D deferral also provides incidental energy benefits. Furthermore, T&D deferral rarely requires more than a few tens of hours of discharge. As a result there are very few hours per year when power is needed for T&D deferral and which arbitrage transactions (“sell high”) might be attractive (i.e., the most likely worst case is that discharge for T&D deferral may conflict with discharge needed for arbitrage transactions during only a few hours per year.)

The implication is that storage used to provide T&D deferral benefits can also provide arbitrage related benefits. Even if storage does not provide T&D deferral benefits in any given year, it can still operate to do arbitrage.

5.c. Time-of-use Energy Cost Savings Plus Demand Reduction

Figure 20. shows load and energy price implications for operation of a storage plant for the combined benefits of demand charge reduction and time-of-use energy cost reduction.

For details about how to calculate the total benefits associated with storage operation for these two complimentary benefits, please see the discussion of demand charge reduction benefits in Section 4 of this document. In that section, calculations for both the demand charge reduction and the related energy benefits are shown.

5.d. Renewables Time Shifting Plus Arbitrage

It is often suggested that energy storage could be used to significantly increase the value of renewables' intermittent output. In many cases, though, the incremental benefit may not be commensurate with the incremental cost of the storage plant.

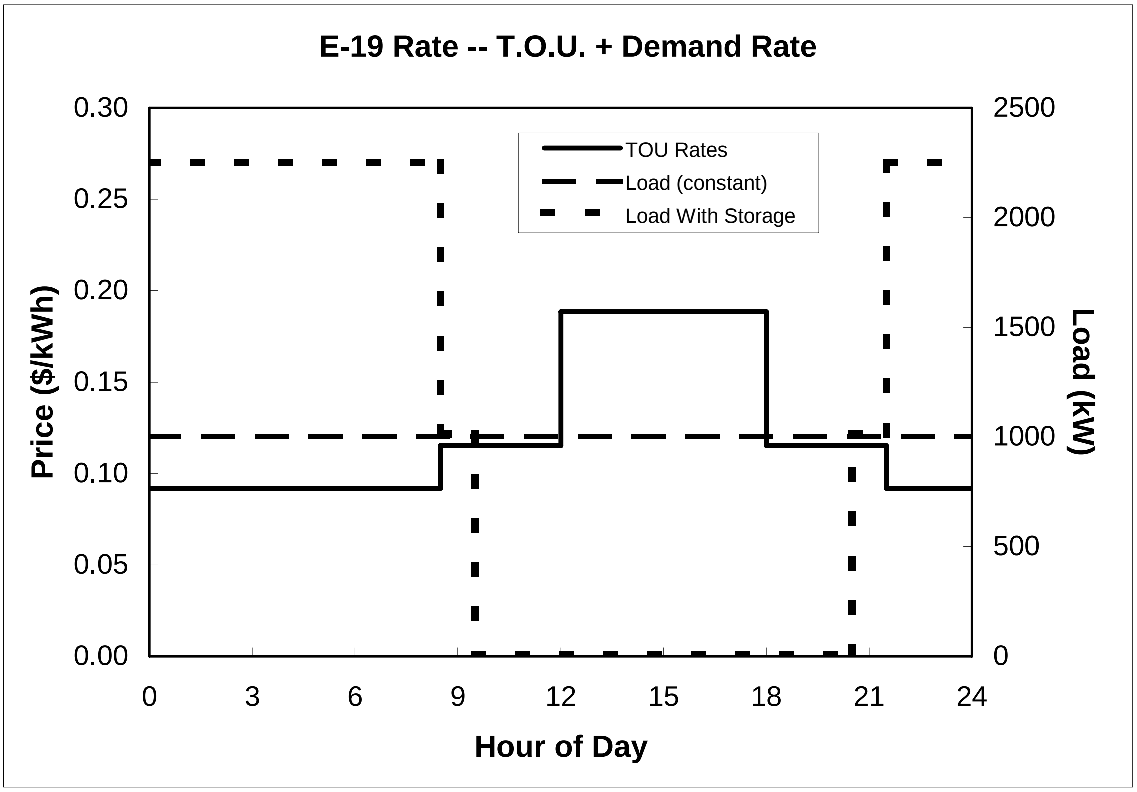

Figure 20. Demand Charge Reduction Based on PG&E's E-19 Rate

Another possibility is a project involving use of storage to time-shift electricity from intermittent renewables and for energy price arbitrage. That would allow storage to provide more services and presumably additional benefit, such that the incremental benefit of storage is increased, hopefully to the point where it is cost-effective.

It may even be that storage could be "decoupled" from the storage plant physically such that other benefits may accrue as well. For example, storage used in conjunction with wind generation could provide transmission support or even, conceivably, T&D deferral benefits; depending on the storage system's location.

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Appendix A – Data Needs for Benefits Estimation

Introduction

This appendix provides a brief overview of the types of data needed to do the evaluations covered in the handbook, and key considerations about alternatives to energy storage. It is designed to be a key indication of next steps for readers who need to estimate benefits or to make market estimates, but whose situation may differ from those described in this document.

Bulk Energy Arbitrage

<u>Data and Evaluation Needs</u>

The key data needed to estimate arbitrage benefits are chronological electric energy prices (hourly or even more frequent). These may be historical (if these are likely to be indicative of the future) or they may be based on forecasts or projections.

A growing number of organizations are posting historical chronological price data on the internet, including independent systems operators (ISOs) and regional transmission operators (RTOs).

Another possible source of chronological price data is public information about electricity price and supply developed using "production cost modeling" by utility planners or state energy regulators.

In special cases it may be worthwhile for an entity considering an arbitrage project to commission an organization to perform custom production cost modeling, especially for multiple scenario evaluations.

Note also that, estimating arbitrage-related benefits using energy storage requires use of a "dispatch algorithm" which performs an hour-by-hour evaluation of whether to charge, discharge, or do nothing. The "decision" is made based on a comparison between: 1) the prevailing price for electricity, and 2) the incremental cost to store and to discharge electricity using the storage device (which is itself a function of the price of electric energy for charging, storage efficiency, and storage variable maintenance cost).

<u>Key Considerations about Alternatives to Energy Storage</u>

Based on the definition of electricity price arbitrage used herein – buy low, sell high – then some type of energy storage is required. Currently only larger, conventional types of electricity storage (e.g., batteries, pumped hydroelectric and compressed air energy storage) are mature enough. Energy storage using hydrogen may compete at a later time.

Central Generation Capacity

Data and Evaluation Needs

State-specific central generation capacity benefits can be determined in two ways: 1) the market clearing price for intermediate capacity as posted on ISO websites or state energy offices, or 2) by examining the cost of recent intermediate capacity factor central power plants installed in the state or nearby, once again usually this information should be publicly available at state energy offices. The market clearing price data may be presented in $/kWh for 24 hour days; these must be summed over the part of the year during which the storage device would be dispatched to obtain $/kW-yr information.

A less convenient source of such data would be from utility generation resource planners, who traditionally use proprietary and sophisticated models and data sets to guide the selection and timing of the next generation resource to be purchased.

Key Considerations about Alternatives to Energy Storage

The issue of when to dispatch the storage device to maximize capacity value is not straightforward. To be dispatched the device must first be charged, which itself may require purchase of capacity rights. The perfect discharge of a storage device to maximize value must take into account the timing of the capacity value hour by hour and the efficiency and variable operating costs of such a storage device.

The primary alternatives to energy storage include central power plants operated at part load (since storage cannot by definition be dispatched more than 50% of the time), and blocks of direct load control and distributed generation (DG).

Resources

Data on the value of central generation can likely be found on ISO websites, and state energy offices. FERC may also have relevant data.

Ancillary Services

Data and Evaluation Needs

Ancillary services benefits are based on actual utility avoided cost and/or market-based pricing for ancillary services.

Increasingly, organizations responsible for oversight of ancillary services are posting historical and current ancillary services price data on the internet, especially independent system operators (ISOs) and regional transmission organizations (RTOs). Price forecasts for ancillary services are less common.

Key Considerations about Alternatives to Energy Storage

The primary alternatives to energy storage include central power plants operated at part load, and central power plants operated specifically for ancillary services. In addition, blocks of direct load control and distributed generation (DG) could provide some ancillary services (e.g., spinning reserve, voltage regulation, etc.).

Resources

FERC description of Ancillary Services; for example, that contained in Notice of Proposed Rulemaking, available at:
http://www.ferc.gov/industries/electric/indus-act/smd/nopr/08-12-03-nopr.pdf

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ISO New England, http://www.iso-ne.com/.

New York ISO, http://www.nyiso.com/markets/index.html#AncillaryServices

Transmission Support

Data and Evaluation Needs

Transmission support benefits cannot be generalized; they must be estimated on a case-by-case basis. Normally the evaluation would include consideration of the types and durations of line-loading anomalies, and evaluation of multiple contingencies as envisioned over several future years. Also needed is the projected capital cost of any planned upgrade, and/or the economic risk to the system if an upgrade is not done.

Readers should note that this evaluation can often be very complicated, involving a complex set of parameters and interactions, and the effects on the transmission system being evaluated are highly non-linear.

Specifically, to determine the need for and benefit from energy storage for transmission support some of the data required are: circuits' dynamics such as a) feedback loops, b) current flow patterns, c) instantaneous loadings on the wires, transformers and couplings involved, d) current and voltage fluctuations, e) temperature-related effects, and f) existing contingencies affecting and affected by the system being evaluated. Evaluations must be undertaken for situations when the system is most stressed. An important criterion may be outage history for the system being evaluated – to contrast it with the system with improvements.

Key Considerations about Alternatives to Energy Storage

For many possible situations there is no alternative to energy storage for this application. In many other cases various types of conventional transmission upgrades are the competition for storage. Often, the do nothing option is also a competitor.

Transmission Access and Transmission Congestion

Data and Evaluation Needs

Transmission access benefits are based on some combination of 1) utility avoided cost (for transmission capacity), 2) charges specified in transmission services contracts, or 3) market-based pricing.

Utility avoided costs are driven by annual carrying charges for the transmission "assets." In a growing number of circumstances regional ISOs or RTOs oversee the transmission marketplace and are responsible for establishing transmission-related charges (access charges and congestion charges). Data from both sources should be publicly available.

Transmission congestion charges are just emerging making related benefits difficult to estimate.

Key Considerations about Alternatives to Energy Storage

Of course, the primary alternative to storage for these transmission-related benefits is an addition to or an upgrade to the transmission system (capacity), though additions and upgrades are increasingly problematic, for a variety of reasons.

Other technically viable alternatives to energy storage for these transmission-related benefits include, blocks of geographically targeted direct load control and energy efficiency, and DG. These would be used 1) if those resources will reduce loading on the transmission system as needed and 2) when time-specific transmission charges make generation or load shedding financially attractive.

Finally, innovative tariffs reflecting locational marginal pricing may be used in lieu of storage for these applications. If ratepayers and stockholders are better off by reducing revenues – rather than increasing the amount of equipment that is owned – then innovative tariffs could compete with storage.

Deferred Transmission & Distribution Upgrade Investment

Data and Evaluation Needs

For specific projects data needed to evaluate the technical viability of storage for T&D deferral includes: 1) historic hourly load during peak demand periods, 2) load growth rate, 3) T&D equipment rating (nominal and emergency) before and after the upgrade to be deferred.

Ideally, information regarding new loads is available; including 1) large housing or commercial real estate developments or 2) new commercial or industrial loads at existing facilities.

The annual carrying charges for the upgrade must be calculated, that is the single year benefit if storage is used to defer the upgrade for one year.

If the capital cost is available for the upgrade to be deferred, that and the utility's fixed charge rate can be used to estimate the deferral benefit. (The fixed charge rate is used to convert a total cost into annualized payments.)

In some cases, typical annual carrying costs are known.   They are expressed in units of $/kW-year. When such a value is multiplied by the T&D capacity to be added (in units of kW) the result is the annual carrying charges for the project, the single year deferral benefit.

Key Considerations about Alternatives to Energy Storage

Depending on circumstances geographically targeted direct load control and energy efficiency, and DG may be technically and financially viable alternatives to storage.

Storage may have an advantage over DG if 1) the discharge duration required is short, 2) annual run hours required exceed 100 to 200, and 3) in areas with strict air regulations or other siting restrictions.

Innovative tariffs reflecting locational marginal pricing may be used in lieu of storage for this application.

Reduced Time-of-Use Energy Cost

Data and Evaluation Needs

The key source of information for estimating benefits from reducing time-of-use energy charges are the applicable tariffs. To the extent that they affect time-of-use energy prices, also needed are forecasts of 1) fuel prices, 2) wholesale electricity pricing, and 3) transmission access and congestion charges.

Time-of-use energy tariffs are usually available at utility web sites. In some cases tariffs or web links to them may be found at state Public Utility Commissions and/or Energy Offices.

Key Considerations about Alternatives to Energy Storage

The primary alternatives to storage are: 1) load reduction when high energy prices prevail, 2) energy efficiency, and 3) DG dispatched when grid energy price exceeds marginal cost of energy from the DG.

However, readers should note that operating DG for several hundred hours per year (needed to reduce energy use when high prices apply) may be quite challenging when considering fuel, siting, noise and air emission implications.

Reduced Demand Charges

Data and Evaluation Needs

The key information used to estimate the financial benefit for reducing demand charges is the applicable tariff. To the extent that they affect demand charges, also needed are forecasts of transmission access and congestion charges.

Tariffs reflecting demand charges are often available from utility web sites. In some cases tariffs or web links to them may be found at state Public Utility Commissions and/or Energy Offices.

Key Considerations about Alternatives to Energy Storage

The primary alternatives to storage for demand charge management are: 1) load reduction when demand charges apply, 2) energy efficiency to reduce “base” load, and 3) DG dispatched when the demand charge reduction benefit exceeds marginal cost of energy from the DG.

Energy efficiency can only reduce total load by so much. If additional demand reduction is needed then load reduction (turning off non-vital equipment) or DG may be required.

Using DG for 600 to 700 hours per year (needed to reduce demand charges in many cases) can be quite problematic when considering air emissions, noise, siting, and fuel handling and storage.

Reduced Reliability-related Financial Losses

Data and Evaluation Needs

Benefits from storage for this application are very circumstance-specific. As such, the only way to get an accurate accounting of the financial benefit for specific end users is to perform an audit, to determine financial losses that can be avoided.

For a more general perspective (e.g. policy or marketing); there are data available which provide some indication of the magnitude of financial losses that can be avoided if reliability is improved, though none are definitive. Some references that may prove helpful regarding historical incidences of outages and the economic impacts on end-users are:

Ron Allan and Roy Billinton, *Probabilistic Assessment of Power Systems*, Proceedings of the IEEE, Vol. 88, No. 2, February 2000.

Gary Wacker and Roy Billinton, *Customer Cost of Electric Service Interruptions*, Proceedings of the IEEE, Vol. 77, No. 6, June 1989.

Roy Billinton, Gary Wacker and E. Wojezynski, *Comprehensive Bibliography on Electrical Service Interruption Costs: 1980-1990*, IEEE Transactions on Power Apparatus and Systems, Vol. 102, No. 6, June 1993.

A. P. Sanghvi, *Economic Costs of Electricity Supply Interruptions: US and Foreign Experience*, Energy Economics, Vol. 4, No. 3, July 1982.

See also references [7], [8], [9a] and [9b] in the End Notes section.

Key Considerations about Alternatives to Energy Storage

The primary alternatives to energy storage include: 1) DG, and, depending on the primary cause of outages, either 2) a more robust distribution system or 3) additional distribution feeds into the same facility.

It is important to note that load-specific storage (i.e., conventional uninterruptible power supplies, UPSs) may be less expensive than larger facility wide systems or even systems located within the distribution grid. Costs of many current models of UPSs range from $150/kW to $250/kW.

Reduced PQ-related Financial Losses

Data Needs

Benefits for improved power quality are very situation-specific. To estimate them a situation-specific evaluation is needed. It includes consideration of the types of and durations of power quality problems and the resulting financial losses.

For a more generalized evaluation (e.g., policy or marketing) related data and evaluations are available in the public domain from a variety of sources, public and private. See, for example, [7] [8] [9] [16] and [22].

Key Considerations about Alternatives to Energy Storage

Depending on specifics about the types and durations of power quality problems, there are alternative solutions to energy storage. In some cases conventional alternatives may be viable (e.g. static VAR compensators and capacitors, or even more significant distribution system upgrades). In other cases line filters may be sufficient or load-specific UPSs may be the best solution.

Increased Revenue from Renewables Capacity Firming

Data Needs

Key data needed to estimate benefits for this application are:

1. Wind or insolation patterns and resulting time-specific output from renewables. In the U. S., that information is available from various sources

including many state energy offices, the U. S. Department of Energy and its National Laboratories, and in some cases advocacy groups such as the American Wind Energy Association.

2. Information about what capacity is worth (based on the cost of generation capacity "on the margin," market projections, or contract terms). Also needed are energy-related payments that may apply (in addition to capacity related payments.) For example, see the PJM renewable capacity credit for wind [18].

Key Considerations about Alternatives to Energy Storage

The primary alternatives to energy storage are 1) central generation operating at part load, 2) direct load control, and 3) "dedicated" generation which is either co-located with the renewables generation or located at or near loads.

Increased Revenue from Renewable Energy Time-shift

Data Needs

Key information needed is typically specified in the terms and conditions in the contract between the renewable system owner and the party agreeing to purchase the energy.

Important data needed to estimate benefits for this application are wind or insolation patterns and resulting time-specific output from renewables. In the U. S., that information is available from various sources including many state energy offices, the U. S. Department of Energy and its National Laboratories, and in some cases advocacy groups such as the American Wind Energy Association.

Key Considerations about Alternatives to Energy Storage

A weak alternative to energy storage for this application could be hybridization of the renewable generation plant using a dispatchable power plant fueled with renewable fuels: geothermal heat, biomass, biogas, or hydrogen.

General Resources

American Wind Energy Association (AWEA), http://www.awea.org

National Renewable Energy Laboratory, http://www.nrel.gov

Electricity Storage Association (ESA), http://www.electricitystorage.org

Electrical Energy Storage – Applications and Technology (EESAT), http://www.sandia.gov/eesat/

Midwest ISO, http://www.midwestiso.org

California ISO, http://www.caiso.com

ISO New England, http://www.iso-ne.com/

PJM RTO, http://www.pjm.com

New York ISO, http://www.nyiso.com

Sandia http://www.sandia.gov

ORNL http://www.ornl.gov

EPRI Power Applications Research Center (PEAC), http://www.epri-peac.com

Federal Energy Regulatory Commission, http://www.ferc.gov

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