RFP Attachment 14

Electric Energy Storage
Benefits and Market Analysis

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Definitions

Alternate Assumption – A value used to calculate benefits or market potential that is different than the respective Standard Assumption Value.

Alternate Calculation – A method used to calculate benefits or market potential that is different than the respective Standard Calculation.

Arbitrage – See Bulk Electricity Price Arbitrage.

Benefit – See Financial Benefit.

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

Bulk Electricity Price Arbitrage (Arbitrage) – Purchase of inexpensive electricity during off-peak periods when demand for electricity is low to charge the EES 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 (energy end-users).

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

Combined Applications – EES used for two or more compatible applications.

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

Demonstration Benefit – The net present value of financial benefits that would accrue if the demonstration plant were to operate for ten years.

Demonstration Benefit/Cost Ratio (Demonstration B/C) – Ratio of Demonstration Benefit to Demonstration Cost.

Demonstration Project Cost – The financial resources ($) needed to design, purchase install, and operate the system over the study period.

Demonstration Lifecycle Cost – The net present value of financial benefits that would accrue if the demonstration plant were to operate for ten years.

Demonstration Lifecycle Cost includes 1) Demonstration Project Cost plus 2) costs incurred in “out years.”

Discharge Duration – Total amount of time that the EES 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; also called the capitalization rate. For the RFP the standard assumption value is 10%.

Economic Benefit – Gross financial benefits that accrue to all beneficiaries using EES as demonstrated.

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

EPRI – Electric Power Research Institute

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

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 and 0.2 for non-utility owners.

Price Inflation Rate (Inflation) – The average annual rate at which the price of goods and services increases during a specific time period. For this RFP the standard assumption value for inflation is 2.5%/year.

Lifecycle – See Financial Life.

Lifecycle Benefits – Net present value of financial benefits that are expected to accrue over ten years for an EES plant.

Mature Benefit – The ten year net present value of financial benefits that would accrue from operation of EES plants like the one being demonstrated, under typical circumstances.

Mature Benefit/Cost Ratio (Mature B/C) – Ratio of Mature Benefit to Mature Cost.

Mature Cost – the mature cost for a system similar to the one proposed for a specific demonstration.

Market Estimate – The estimated amount of EES capacity (MW) that the Bidder expects to be installed over ten years in California. Estimates are for EES plants like those to be demonstrated. 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 EES in California, estimated based on reasonable assumptions about technology and market readiness and trends, and about the persistence of existing institutional challenges. It can also be thought of as the plausible market potential, in California, for a given program application. (For context, the Maximum Market Potential is a portion of the Market Technical Potential.)

Market Technical Potential – The estimated maximum possible amount of EES (MW and MWh) that could be installed over ten years in California, given purely technical constraints. For the RFP this is either 1) all load growth for most utility-owned EES systems, 2) system peak load for end-user applications, 3) the maximum amount of renewables generation for renewables-related applications.

Net Present Value Factor (NPV Factor) – A number used to convert an annual financial payment into the net present value for a series of such equal payments. A NPV 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 NPV factor is 7.17.

Plant Rating (Rating) – EES 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.

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 EES plant/system per unit of electric energy input.

Screen (Screen out) – Eliminate from consideration projects that do not satisfy legal and other administrative criteria or that do not meet minimum requirements for project benefit/cost, cost-sharing, or that exceed co-funding targets.

Standard Assumption Values (Standard Values) – Values provided by the Commission for use by Bidders when making the required standard calculations for benefits and for market potential. For example, financial benefits are calculated based on the following standard assumptions: a ten year lifecycle, 10% discount rate, and 2.5% annual inflation. See also Standard Calculations.

Standard Calculations – Calculation methodologies – used in conjunction with Standard Assumption Values – to calculate benefits and market potential. For example, the program team has established a Standard Calculation methodology for estimating Arbitrage benefits. See also Standard Assumption Values.

Storage Discharge Duration – See Discharge Duration.

Storage System Life (System Life) – the period during which the EES system is expected to be operated.

1. Introduction

1.a. About This Document

This document describes 1) electric energy storage (EES) applications that might be demonstrated, 2) the types of benefits that EES provides when used for the application and how to estimate their financial value, and 3) criteria for estimating market potential for the application.

Bidders should note that RFP Attachment 12 is an important companion document to this one. RFP Attachment 12 includes forms to be used by Bidders to document cost, benefit, and market values described below.

1.b. EES Program Mission

Demonstrate electric EES as a technically viable, cost-effective and broadly applicable option for reliable electricity system capacity and for electric energy management in California.

1.c. Philosophy

In general, it is the intention of this RFP to be consistent with the EES Program Mission. This attachment is to assist Bidders in preparing the information requested in this RFP that addresses market and benefit analysis.

The Commission has attempted to tailor a system that balances prudence with the cost to perform rigorous benefits assessments and market projections. The process was designed to be transparent and to require a reasonable level of rigor while emphasizing credibility of market and benefit estimates.

This document provides the standard assumptions for calculating the potential market size and benefits associated with EES plants.

The reason for providing that framework is twofold:

1. provide respondents to the RFP with helpful guidance about how to estimate benefits and market potential, and
2. to the extent possible, for fairness and to be practical, the EES demonstration selection process and framework have to be standardized, to allow for consideration of a variety of demonstrations using consistent bases.

As noted above, the Commission intends to be inclusive and to encourage innovation both with respect to technology and also to value propositions for EES, consistent with the Program Mission.

Given the need for use of consistent bases, standard assumption values are provided for most of the important criteria used for benefit calculations and market estimates. However, Bidders may also provide results based on alternate assumptions and/or alternate calculation methods.

Whatever a Bidder chooses to do in this regard, to be responsive to the RFP they must provide all of the required data and information in the form requested.

Results based on alternate assumptions and/or alternate calculation methods must be documented by the Bidders, along with the rationale and the actual alternate assumptions and alternate calculations made.

1.d. Process Overview

Demonstration Benefit, Cost, and B/C Ratio

Figure 1 illustrates the process followed to estimate the benefit, cost, and benefit/cost ratio for the EES demonstration (Demonstration B/C ratio).

Once the application and site are selected, and the projected ten-year benefit is estimated. The demonstration costs established and the demonstration financial benefits are estimated.

- The demonstration project cost must be developed entirely by the Bidder, based on factors such as project site, application, EES discharge duration, all plant maintenance requirements, plant tear-down requirements, etc. It is the Bidders responsibility to ensure that all costs are clearly identified.

- The demonstration benefit is the net present value of all benefits that *would* accrue if the demonstration plant were to be operated for ten years. Note that even if the plant will not actually operate for ten years the demonstration benefit is estimated as-if the plant *will* operate for ten years.

One of the criteria used to screen proposals is the demonstration B/C ratio. It is calculated as the demonstration benefit divided by the demonstration lifecycle cost. The demonstration lifecycle cost is the sum of the demonstration project cost and the net-present-value of all costs that will or that would be incurred if the demonstration plant were to be operated in a manner needed to yield the demonstration benefit.

Consider an example. A demonstration will be installed, operated for two years, and dismantled for $1 Million. The ten year estimated benefit is $600,000 (net present value).   The cost to operate EES for eight years beyond the period of performance for the Program is $250,000.
Benefit = $600,000
Cost = $1 Million + $250,000 = $1.25 Million
B/C ratio = $600,000 / $1.25 Million = .48

Important Note: a minimum demonstration B/C ratio of .3 is required if proposals are to satisfy the minimum demonstration B/C ratio screening criterion.

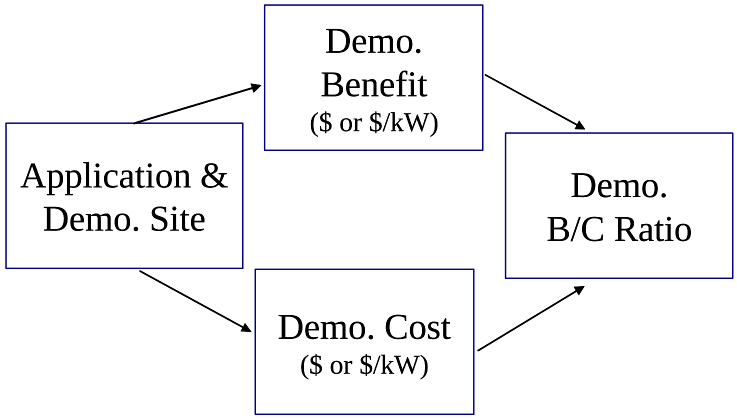

Figure 1. Process for Estimating Demonstration B/C Ratio

Mature Benefit, Cost, B/C Ratio

Figure 2 shows, conceptually, the process to estimate the mature B/C ratio, the market estimate, and the economic benefit to California.

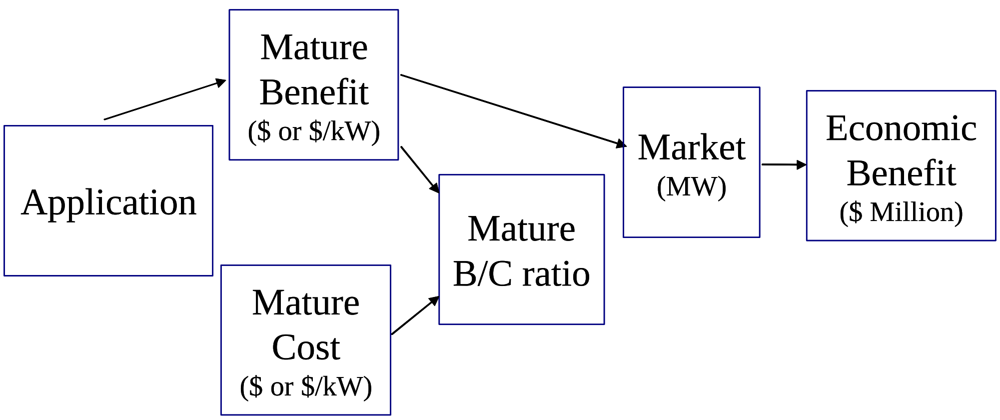

Figure 2. Process for Estimating Market Size and Mature B/C Ratio

First, after selecting an application, each of the presumed financial benefit or benefits associated with EES are summed to calculate the mature benefit. If more than one benefit is claimed then benefits must be reconciled with regard to time, technical, and institutional "conflicts."

Demonstration benefits (benefits specific to the demonstration plant) and mature benefits (those accruing to more typical situations in the future) may or may not be the same. If the demonstration plant's circumstances are typical then demonstration benefits would indeed be the same as mature benefits. If the demonstration circumstances are not typical or if a benefit claimed does not exist at present then the demonstration benefits and the mature benefits will differ.

Second, the mature cost of the EES technology (being demonstrated) is estimated. The mature cost is net present value of the entire cost to own and to operate the plant for ten years. It must be developed entirely by the Bidder based on factors such as the application being served, EES discharge duration, plant maintenance requirements (including overhauls), etc. It is the Bidders responsibility to ensure that all costs are clearly identified.

Finally, based on the mature (plant) benefit and mature cost, the mature benefit-to-cost ratio is calculated by dividing the mature benefit by the mature cost.

Important Note: a minimum mature B/C ratio of 1.0 is required if proposals are to satisfy the minimum mature B/C ratio screening criterion.

Market Estimate and Economic Benefit to California

A market estimate in megawatts (MW) is provided by Bidders for EES plants (like that being demonstrated). The estimate reflects the amount of EES that the Bidder will deploy, in California, over the next decade.

Finally, the total economic benefits that will accrue in California are estimated. That estimate is based on the mature benefits ($/kW of EES) times the market estimate (MW). As an example, for EES whose benefit is $600/kW and for which the market estimate is 200 MW, the total economic benefit is $120 Million.

1.e. Technical Notes

Compliance with All Applicable Safety and Electrical Rules and Standards

It is up to Bidders to verify that the demonstration plant design meets all applicable and relevant electrical, safety, and fire rules, regulations, and requirements. That includes all relevant power quality standards and utility interconnection rules and regulations.

Real, Apparent, and Reactive Power

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

Nominal versus “Emergency” Power Rating

Some types of EES systems can discharge at a relatively high rate for relatively short periods of time (often referred to as “emergency” rating). For this RFP the discharge rate is the design rate or nominal rate.

For example, an EES device can operate at a nominal rate of 1 MW, for 3 hours at 80% efficiency. The same plant can provide 1.5 MW for up to ten minutes, at 65% efficiency. For this example, within this document, the plant power (rating) would be specified as 1 MW.

However, if a Bidder can show that there is a specific benefit associated with the ability to discharge at a higher rate for short periods, then the benefit may be included in the total benefits for the plant. As an example: EES used to reduce peak demand in one building with 1 MW of load could carry 500 kW of load from a second building during an outage, to allow enough time for an orderly shutdown of sensitive processes.

1.f. Summary of Key Standard Assumption Values

Table 1 below provides a summary of key standard assumption values for use in this RFP.

Table 1. Summary of Key Standard Assumptions

Applications	Discharge Duration* Minimum	Discharge Duration* Highest	Lifecycle Financial Benefits ($/kW)	Maximum Market Potential (MW)	Ten-year Economic Benefits ($Million)**
Bulk Electricity Price Arbitrage	1	10	200 to 300	735	147 to 220
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
T&D Support	2 Seconds	5 Seconds	82	1,000	82
Customer Time-of-Use Energy Cost Management	2	see tariff	1,004	4,005	4,021
Customer Demand Charge Management	6	11	465#	4,005	1,862
End-user Electric Service Reliability	.25	5	359	4,005	1,438
Renewables Capacity firming	6	10	172##	1,800	310
Renewables Contractual Time-of-Production Payments	6	11	655##	500	326
T.O.U. Energy Rates Plus Demand Charge Reduction	6	11	866	4,005	3,468
Benefits					
Avoided Central Generation Capacity Cost	4	6	215	3,200	688
Ancillary Services	1	5	72***	800	58
Avoided Transmission Access Charges	1	6	72***	3200	230
Reduced PQ-related Financial Losses	10 seconds	1 Minute	717	4,005	2,872

*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 acutal benefit was not estimated.
#Does not include incidental energy-related benefit.
##Wind generation.

2. Electric EES Applications

2.a. Applications Overview

This section describes the eight application types targeted by the program for demonstration.

For convenience, applications are grouped into three categories:
- Grid System
- End-user/Utility Customer
- Renewables

The eight applications (grouped by category) are

<u>Grid System</u>

1. Bulk Electricity Price Arbitrage
2. Transmission and Distribution Upgrade Deferral
3. Transmission and Distribution Support

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

4. Time-of-Use Energy Cost Management
5. Demand Charge Management
6. Electric Service Reliability

<u>Renewables</u>

7. Renewables Capacity Firming
8. Renewables Contractual Time-of-production Payments

It is very important for Bidders to note the distinction made in this document between applications and benefits. Applications (listed above) are specific purposes for which EES is used. Benefits are the financial returns that accrue because EES is used. (In this document, a benefit may be a revenue stream or may be a cost that can be avoided if EES is used: an “avoided cost.”)

EES deployed to serve a specific application may provide multiple benefits. Specifically, a Bidder may be able to show that an EES system used for one of the nine applications targeted by the program for demonstration provides several types of financial benefits.

As an example: an energy end-user stores energy off-peak for discharge on-peak (the time-of-use electricity cost reduction application). As application name implies, the primary benefit is electric energy cost reduction. Depending on circumstances, the EES 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

EES System Power Output Rating

EES output rating is circumstance-specific. The Bidder is responsible for designing a demonstration that provides enough power to serve the designated load, as needed, for applications being served.

EES System Discharge Duration

The EES plant discharge duration is, of course, an important criterion both with respect to technical viability for a given application and plant cost. It is the Bidder's responsibility to establish the appropriate discharge duration for their demonstration

EES System Minimum Reliability

Like power rating and discharge duration, EES system reliability requirements are circumstance-specific. The Bidder is responsible for designing a demonstration 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 purchase of inexpensive electricity available during periods when demand for electricity is low, to charge the EES 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 EES 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 EES (discharge duration).

Section 4 of this attachment 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 minimum discharge duration for this application is one hour.

Though 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

T&D Deferral Application and/or could provide transmission congestion relief, plus benefits for reliability and/or improved PQ and/or ancillary services.

Application #2. 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 EES.

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 EES 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 "engineering rating" (often engineering rating is often 20% to 30% below nameplate rating, units are MW or MVA). 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 will consider installing enough EES to meet the expected load growth for next year, plus an engineering contingency.

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

The key concept is that a small amount of EES 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 EES 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 and/or may provide benefits for reliability and/or PQ and/or ancillary services.

Application #3. Transmission and Distribution Support

Application Overview

EES 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 and distribution support (T&D support). The benefits from T&D support are very situation- and site-specific.

Table 2 lists and briefly describes ways that EES can provide such T&D support.

Table 2. 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	1. Transient Voltage Dip Improvement Increase load carrying capacity by reducing the transient voltage dip following a system disturbance. 2. Dynamic Voltage Stability Improve transfer capability by improving voltage stability margins.
Under-frequency Load Shedding Reduction	Reduce under-frequency load shedding during large system disturbances through injection of real power.

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

Technical Considerations

To be used for T&D support, EES must be capable of 1) sub-second response, 2) operation at partial states of charge, and 3) many charge-discharge cycles.

EES used for this application must also be very reliable. Typical discharge durations for this application are between one and twenty seconds. For EES to be most beneficial as a T&D support resource it would provide real and reactive power. [6]

2.d. Customer/End-use Applications

<u>Application #4. Time-of-Use Energy Cost Management</u>

Application Overview

The time-of-use electricity cost management application (time-of-use application) involves EES used by energy end-users (utility customers) to reduce their overall costs for electricity. Customers charge the EES 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.

It is similar to arbitrage, though the prices paid for energy by the customer are based on the customer's tariff, rather than the prevailing wholesale price for electric energy.

For the example, 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 power requirements are less than or equal to 500 kW are eligible for the A6 tariff.

As shown in Figure 3, 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.

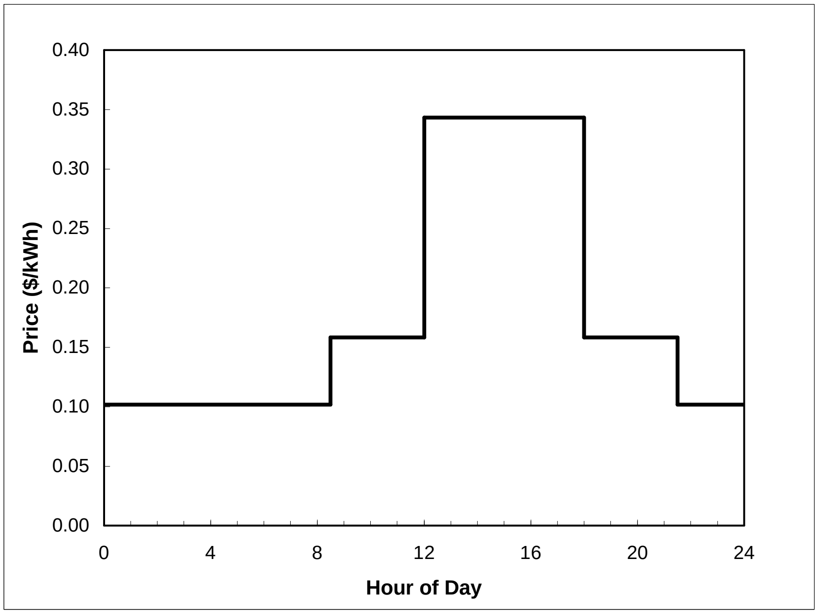

Figure 3. Summer Energy Prices for PG&E's Small Commercial A-6 Time-of-use Rate

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 P.M. 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 reliability.

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

Application #5. Demand Charge Management

Application Overview

EES could be used by energy end-users (utility customers) to reduce overall cost 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 fifteen minute period, during times and months when peak demand charges apply, the monthly demand charge is not avoided.

As shown in Figure 4, energy end-users charge the EES during off-peak time periods when the electric energy price is low. The energy stored serves demand during times when demand charges apply. Typically, EES must discharge for five to six hours for this application, depending on provisions of the applicable tariff.

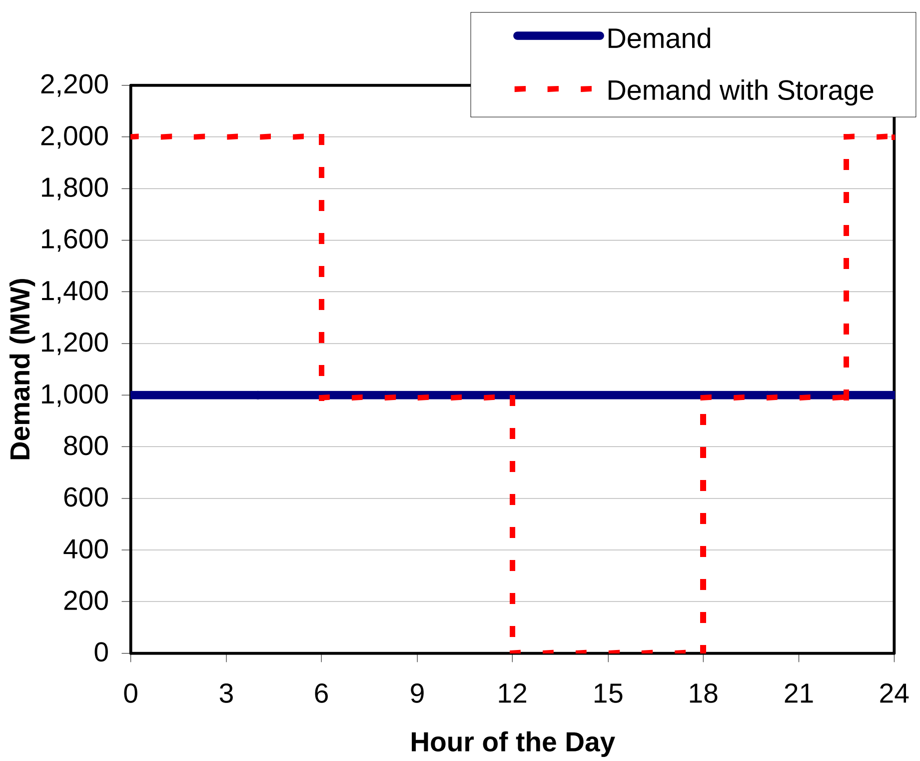

Figure 4. Demand Charge Reduction Using EES

The example shown in Figure 4 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 EES 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 EES plant discharge duration is driven by the applicable tariff. For example, for PG&E's E-19 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 demonstration of 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 T&D 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 EES is discharging during the entire daily duration of the period when demand charges apply. The plant could also provide benefits associated with improved end-user PQ and reliability.

Application #6. Electric Service Reliability

The electric service reliability application is defined in broad terms: it entails the use of EES to provide high quality and highly reliable electric service for one or more adjacent facilities. The EES system provides enough energy for some combination of the following: an orderly shutdown of processes and/or transfer to on-site generation resources, high quality power needed for on-site, highly reliable service.

Application Overview

EES enables effective system integration of thermal, renewables, and even load control for power parks or small isolated grids.

- Power quality & high-value load reliability
- Voltage stability
- Startup/bridging a generator

Technical Considerations

The discharge duration required is based on complex set of criteria that are very situation-specific.

2.e. Renewables Applications

Application #7. Renewables Capacity Firming

Application Overview

For this application, EES 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 location EES 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.

Typically 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). Project teams must explain the rationale used if storage power output differs from the nameplate rating of the generator.

Application #8. 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.

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

Technical Considerations

Depending on where the EES 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 3 lists application-specific standard assumption values for each program application.

Table 3. Application and Benefit-specific Standard Assumption Values for Discharge Duration

	Discharge Duration		
Applications	Minimum	Maximum	Note
Bulk Electricity Price Arbitrage	1 hour	10 hours	Primarly a function of: 1) incremental cost of adding storage versus incremental benefit (benefit from additional transactions) and to a lesser extent, 2) storage efficiency.
Distribution Upgrade Deferral 50th Percentile of Benefits	2 hours	6 hours	Situation-specific.
Distribution Upgrade Deferral 90th Percentile of Benefits	2 hours	6 hours	Situation-specific.
Transmission Upgrade Deferral	4 hours	6 hours	Situation-specific.
T&D Support	2 Seconds	5 Seconds	Location- and support-type-specific.
Customer Time-of-Use Energy Cost Management	2 hours	see tariff	Maximum discharge duration is based on the applicable tarrif.
Customer Demand Charge Management	6 hours	11 hours	Peak demand period (daily) is based on tarrif. Standard Assumption: Must operate from 12:00 P.M. to 6:00 P.M. on Summer weekdays.
End-user Electric Service Reliability	.25 hour	5 hours	Situation-specific.
Renewables Capacity firming	6 hours	10 hours	Situation-specific. Standard Assumption: need to operate storage from 12:00 P.M. 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	11 hours	Standard Assumption: Could operate storage from 12:00 P.M. to 6:00 P.M. on Summer weekdays.
Benefits			
Avoided Central Generation Capacity Cost	4 hours	6 hours	Needed during peak load hours during peak load days.
Ancillary Services	1 hour	5 hours	Very circumstance, location, and ancillary service-type specific.
Avoided Transmission Access Charges	1 hour	6 hours	Very circumstance specific.
Reduced PQ-related Financial Losses	10 seconds	1 Minute	Very circumstance, location, and customer-type specific.

* Over ten years, in California.

3. Estimating Market Potential

A key facet to the Program is to demonstrate EES for applications with a significant market potential. (Significant is defined as at least 100 MW deployed over ten years in California.)

Given that criterion, there is a need to estimate market potential for EES plants to be used for the application being demonstrated. Included in proposals must be an estimate of the market size for EES systems similar to that being demonstrated (market estimate).

This section describes the philosophy used to estimate market potential and provides related guidance for Bidders to use when making the market estimate for the type of EES system to be demonstrated.

3.a. Market Estimation Approach and Philosophy

Market estimates should be as rigorous as needed to be credible, as judged by the evaluation team. Bases for estimates could include, for example, sales trends and projections, surveys, utility plans, or related market research.

As indicated by the outer square in Figure 5, 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. In California the technical potential is the state's total peak electric demand.

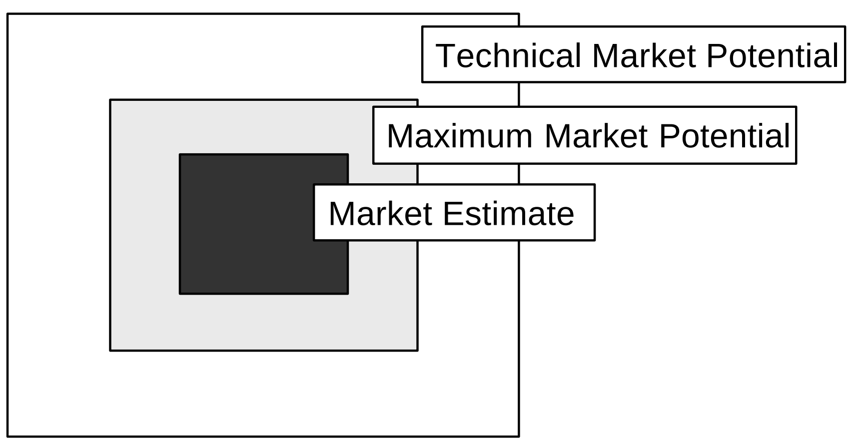

Figure 5. Market Potential and Estimate

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 established without regard to EES cost.

Finally, Bidders must make a market estimate. The market estimate reflects the amount of EES that the Bidder expects to be deployed, over ten years, for the type of EES system being demonstrated.   As shown in Figure 5, the market estimate is some portion of the maximum market potential.

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 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 4 below are from that document.

Table 4. California Peak Load and Load Growth

California Load, Beginning 2004	57,416 MW
Average Peak Load Growth Rate	2.5%/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 EES cost.

Consider an example: given the premise that it is unlikely that EES will displace any existing utility equipment, a simplifying assumption (for utility applications) is that the market for new EES 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.

A standard assumption value is provided for the maximum market potential for each of the nine applications targeted for demonstration by the program. Please see Table 5.

Table 5. Application and Benefit-specific Standard Assumption Values for Maximum Market Potential

	Maximum Market Potential*	
Applications	MW*	Note
Bulk Electricity Price Arbitrage	735	Maximum Market Potential is 1% of Load in 2013.
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
T&D Support	1,000	Estimated based on research by the Electric Power Research Institute.
Customer 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."
Customer Demand Charge Management	4,005	Same as above.
End-user Electric Service Reliability	4,005	Same as above.
Renewables Capacity firming	1,800	Existing wind generation capacity in California.[5]
Renewables Contractual Time-of-Production Payments	500	Qualifying SO4 contracts, wind generation.
Benefits		
Avoided Central Generation Capacity Cost	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	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.[15]
Avoided Transmission Access Charges	3,200	Assume 20% of load growth. 16,000 MW * .2 = 3,200 MW.
Reduced PQ-related 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."

* 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, however, some Bidders may have better information, insights, or understanding of the applications targeted for demonstration. If so, Bidders may develop their own estimates for maximum market potential. However, the onus is on Bidders to provide a credible rationale for those alternate assumption values.

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 ten year lifecycle period for the program – the market estimate. Market estimates must be provided for each demonstration.

Bases for market estimates could include, for example, sales trends and projections, surveys, utility plans, or related market research. Criteria that affect market estimates for EES include systems include, among others: system cost (capital, installation, O&M, etc.), efficiency, marketing costs, and market adoption rates.

Whatever criteria are used, market estimates should developed using a methodology that is as rigorous as needed to be credible, as judged by the evaluation team. The project evaluation team will base their determination – about the credibility of the estimate – on the rationale, assumptions, data, and calculations used to make the estimate.

Market Estimates: EES must be Cost-effective

For this RFP, the mature 10-year lifecycle benefit determined by the Bidder must be equal to or greater than the mature 10-year lifecycle cost to be considered cost effective.

Market Estimates: EES must be Cost-competitive

As described in Section 4 of this attachment, benefits associated with use of EES 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 cost is not competitive are not attractive candidates for demonstration by the program. Specifically, EES systems whose mature cost exceeds the cost of another technically viable option (i.e., can provide the same “utility”) then the EES system to be demonstrated is not a viable solution.

Market Estimates for Combined Applications and Benefits

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

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 EES system benefit ($/kW) but may reduce the overall market potential.

Consider an example: an EES plant is used for the distribution upgrade deferral application. If demonstration teams also include benefits 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 6.

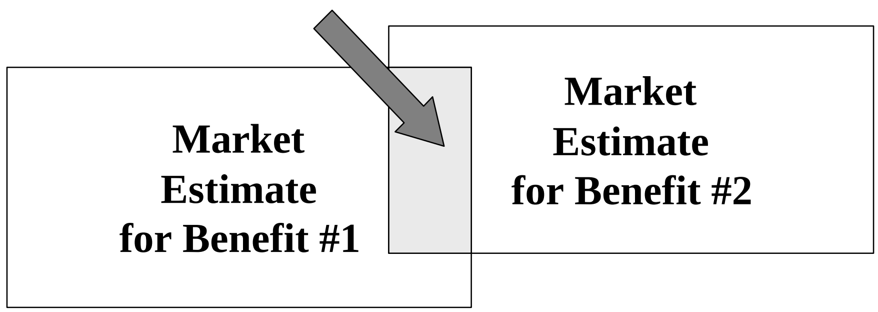

Figure 6. Market Estimation for Combined Benefits: Market Intersection

Proposals must show how Bidders took these considerations into account. Technical scores will reflect how well Bidders addressed this issue.

4. EES Benefits, Financial Viability, and Economic Value

A market and value based evaluation will be used as a partial means to select demonstrations. Such an approach involves an evaluation of the financial viability and economic contribution of EES used for the respective application.

This section discusses the calculation of: 1) financial benefits, in $/kW of EES, 2) mature benefit/cost ratio, and 3) total economic benefits (over ten years). Note that the mature benefit/cost ratio is based on estimated benefits (described below) and EES cost which must be estimated by Bidders. Cost estimates are made based on EES requirements needed for specific applications and benefits.

4.a. Overview

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

Specific types of benefits considered include:

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

Benefit types one through eight in the list above correspond directly to a specific application type. For example, revenue from energy arbitrage is associated with the arbitrage application.

Benefits nine through thirteen in the list are not associated with a specific application though they may apply in specific cases. One example is the power quality (PQ) benefit. Power quality is not an application for the RFP. It is, however, a benefit that may be incidental to use of EES for the demand charge reduction application. Another example is the financial benefit associated with the incidental energy discharged by EES while it serves another application, primarily capacity applications.

Mature Financial Benefit

The mature financial benefit (mature benefit) is the total lifecycle financial benefit associated with use of a commercially mature version of the EES plant being demonstrated.

For this document the standard assumption value for EES system life is ten years. Mature financial benefit is expressed as the net present value of annual benefits, for the ten year life of the plant, in units of $/kW of EES.

If benefit streams vary from year-to year then year-by-year cashflows may be used. If so, it is important to use the same financial bases as those used when estimating benefits. Such non-standard assumptions and calculations must be documented.

If more than one benefit accrues then mature benefits are the sum of individual benefits. Bidders must specify how they qualify and account for multiple benefits.

Mature EES Cost

This document does not address calculation of the cost to own and to operate EES. It is the responsibility of Bidders to develop cost estimates for a mature plant like the one being demonstrated.

It is important for Bidders to include all costs commensurate with the benefits claimed. For example, lifecycle costs must include the net present value of overhauls required (such as cell or electrolyte replacement) for a mature plant like the one being demonstrated, for the assumed plant life.

Of course, mature EES costs must be calculated using financial bases that are consistent with those used to calculate benefits. Specifically they must reflect the cost to own and to operate the EES plant using the same financials (price escalation and discount rate), plant life, and the same plant operational mode as that assumed when estimating mature benefits.

Financial Viability -- Mature Benefit-to-Cost Ratio

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

Total Economic Benefit

Total economic benefit in California is the market estimate (described in Section 3 of this attachment) multiplied by the mature financial benefits.

Consider an example: a market estimate of 200 MW over ten years and mature benefits of $700/kW of EES. The total economic benefit is:

200 MW * $700/kW = 200,000 kW * $700/kW
= $140 Million.

4.b. Financials

For scoring and selection of demonstration proposals it is important that the team have means to evaluate proposed demonstrations using common financial bases. The following sub-sections briefly describe specific financial criteria to use for financial evaluations (i.e., to calculate benefits), including relevant standard assumption values.

Demonstration Lifecycle Benefits

These values are used to estimate the typical amount of total benefits associated with the type of system/application being demonstrated.

Financial Life

For this RFP, a plant life of 10 years is assumed for lifecycle financial evaluations. However, Bidders with compelling reasons to use another plant life may do so as long as it does not exceed 10 years.

Price Escalation

For this RFP, a general price escalation of 2.5% is assumed. Electric energy and capacity costs and prices are assumed to escalate at that same rate during the EES plant's financial life.

Discount Rate for NPV Calculations (Discount Rate)

For this RFP, the discount rate is 10%. It is used for making net present value calculations to estimate lifecycle benefits.

Calculating NPV

The net 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 "net present value factor" (NPV factor) is calculated. That value is used to convert a single/first year value into a net present value. Given the standard assumption values of 2.5% standard cost/price escalation rate, 10% for discount rate, and ten years for EES life the standard assumption value for the NPV 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.

Implicit in the example above is the assumption that annual benefits for all ten 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 the Bidder may submit an actual cashflow evaluation to estimate the lifecycle benefits using a 2.5% escalation, 10% discount, and a 10 year life.

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 equipment's financial life. That annuity equivalent is used to represent the annual carrying charges associated with ownership of capital equipment, in this case EES 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 Revenue from Bulk Energy Arbitrage

Introduction

Arbitrage involves purchase of inexpensive electricity available during periods when demand for electricity is low, to charge the EES 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.)

To estimate the arbitrage benefit, a dispatch algorithm is used. It has the logic needed to determine when to charge and when to discharge EES, 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. EES round trip efficiency
3. EES system discharge duration

Algorithm for Estimating Annual Benefits 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.

A discussion of how to convert that annual arbitrage benefit to a lifecycle/net present value is described 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 7 below shows prices for the entire year of 2003. Note that there are about fifty hours when the price is above $100/MWh (10¢/kWh). During off peak periods (when EES plants are charged) the price is frequently at about $30/MWh (3¢/kWh).

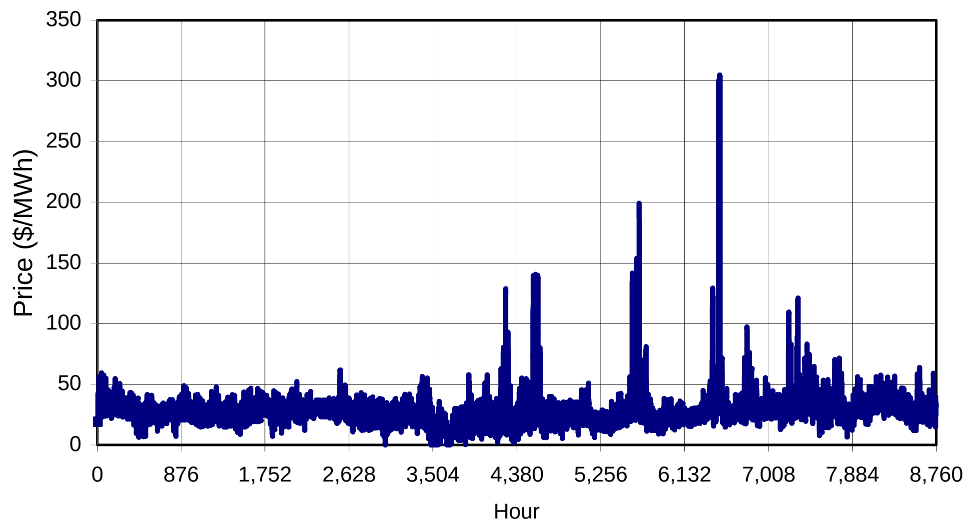

Figure 7. Chronological Electricity Price Data, for California, 2003 (projected)

Arbitrage Annual Benefit

As described above, the EES dispatch algorithm is used to estimate the arbitrage benefit for a given year. Estimates are made for EES plants whose discharge duration ranges from 1 hour to ten hours. Figure 8 below shows estimates for EES plants whose efficiency is 90%.

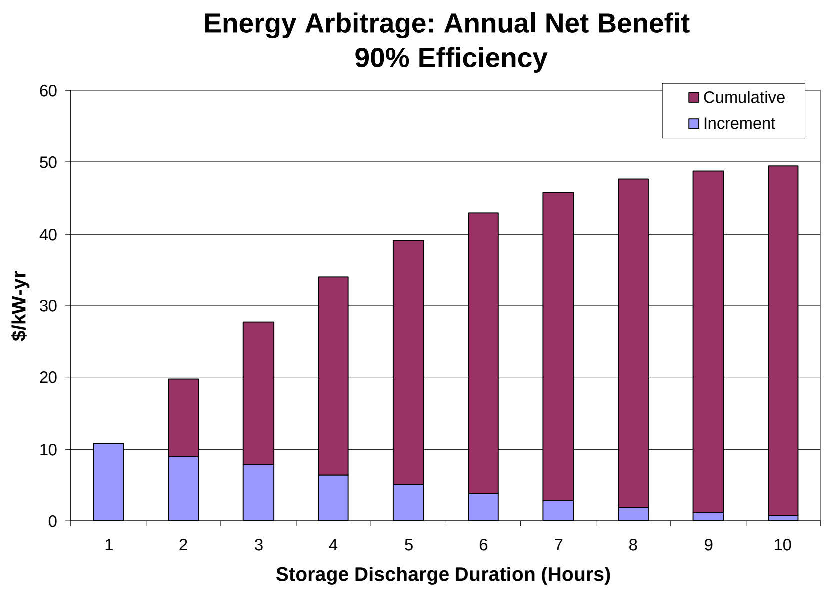

Figure 8. Annual Arbitrage Benefit in California, in 2003, for 90% Efficient Storage, for Discharge Durations Ranging from One Hour to Ten Hours

As shown in Figure 8, as hours of storage discharge duration are added to a EES 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 the RFP the EES plant is assumed to have a useful life of ten years. To convert the one-year value to net present value (NPV) the first year benefit is multiplied by the net present value factor of 7.17.

Consider an example. From Figure above, for a 90% efficient EES 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 NPV factor (7.17) yields a lifecycle NPV benefit of $34 * 7.17 = $245/kW.

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

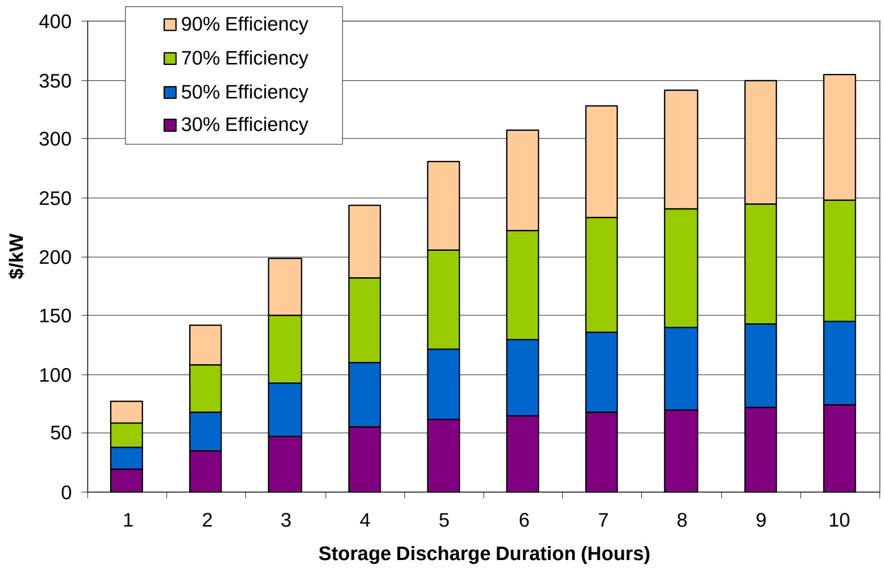

Figure 9. Lifecycle Arbitrage Benefit in California, in 2004, for 30%, 50%, 70% and 90% Efficient Storage, With No Variable Maintenance Cost for Discharge Durations Ranging from One Hour to Ten Hours

To illustrate the concept of converting a one-year arbitrage benefit to a lifecycle, note that the top of the bar (plot) for EES systems with four hours of discharge duration corresponds to lifecycle benefits of about $245/kW. That value is the lifecycle benefit for the EES 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 EES . 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 O&M for each EES 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 EES 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 EES 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 EES plant is 3¢/kWh. If the EES 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

The Bidder is responsible for including these effects in their estimates of arbitrage benefits for EES plants like the one being demonstrated.

Figure 10 and Figure 11 below provide lifecycle benefits for EES plants whose variable operation cost is 1¢/kWh and 2¢/kWh respectively.

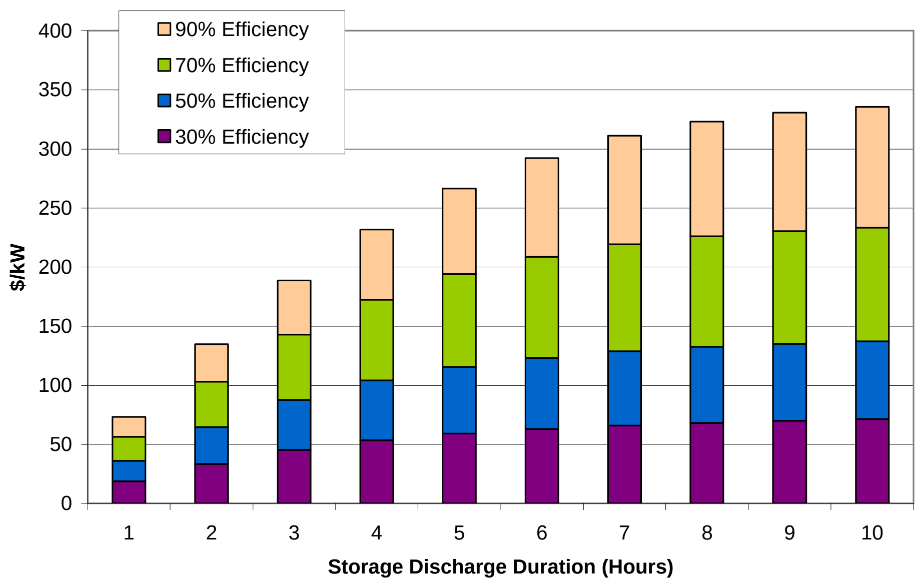

Figure 10. Lifecycle Arbitrage Benefit in California, in 2004, for 30%, 50%, 70% and 90% Efficient Storage, With Variable Maintenance Cost of 1¢/kWh for Discharge Durations Ranging from One Hour to Ten Hours

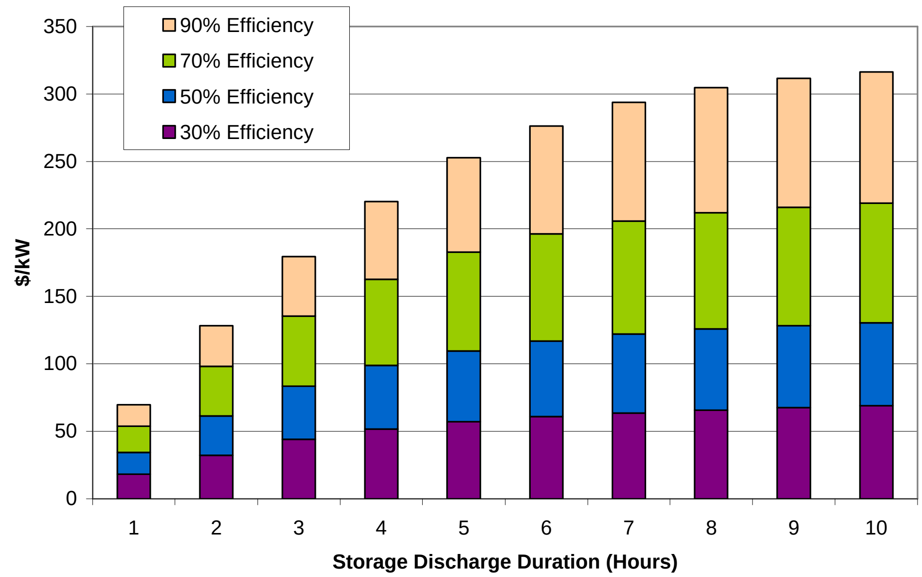

Figure 11. Lifecycle Arbitrage Benefit in California, in 2004, for 30%, 50%, 70% and 90%Efficient Storage, With Variable Maintenance Cost of 2¢/kWh for Discharge Durations Ranging from One Hour to Ten Hours

Benefit #2 Deferred Transmission and/or Distribution Upgrade Investment

T&D Upgrade Deferral Benefit Overview

A transmission and distribution (T&D) upgrade deferral benefit (deferral benefit) is the financial value associated with deferring a utility T&D upgrade for one or more years.

For each year of deferral, the deferral benefit (financial carrying charges) is calculated by multiplying the annual 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.

Locations for which distributed resources, including distributed EES, 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
- T and/or D upgrades required are "lumpy" (i.e., for one or a few years a small amount of storage can defer a relatively large investment
- high transmission access charges (that can be avoided with distributed resources)

EES Power Output Requirements

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

Consider the example illustrated in Figure 12. 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 * .025 = 225 kW.

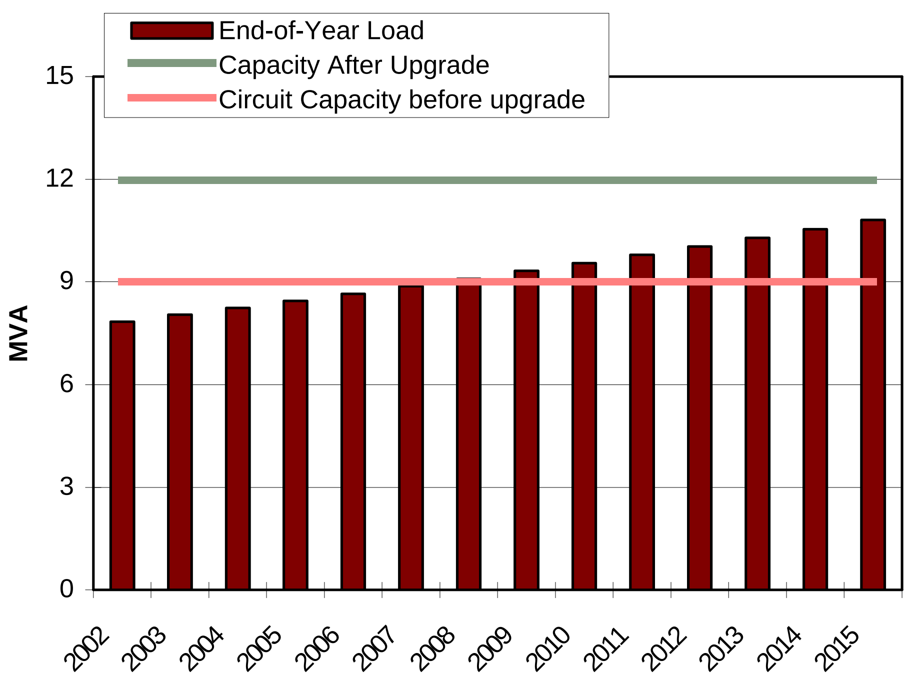

Figure 12. Distribution Peak Load, Capacity, and Upgraded Capacity

So, in theory, an EES 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, EES oversizing may be indicated.

EES Discharge Duration Requirements

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

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 13. The figure in the upper left shows load in "year 0," the year before the distribution capacity is expected to be loaded up to its rating. The lower right figure 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.

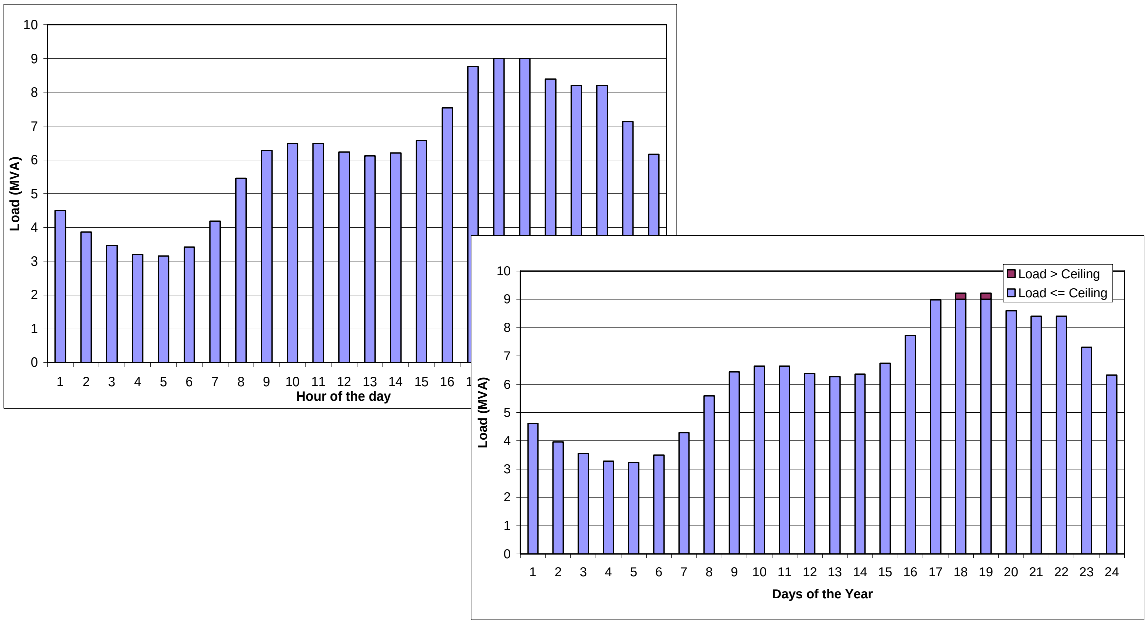

Figure 13. EES Sizing to Meet Peak Demand:
Energy Requirements for a Single Year's Load Growth

The number of hours during which load exceeds the demand ceiling is the EES 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 EES plant. This is intended to reflect conservative engineering design.

In the example in Figure 13, 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 EES duration required, for this example. When addressing engineering contingencies it may be prudent to make the discharge duration longer.

Financial Cost for Distribution Upgrades

As a way to generalize benefits associated with EES for T&D deferral the annual utility benefit is expressed in units of $/kW per year. This represents the utility cost to own and to operate one kW of T&D capacity for one year.

Annual cost per 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.)

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

Additionally, for 10% of locations requiring upgrades, cost exceeds about $608/kW.[4] The resulting single year carrying charges are 0.13 * $608/kW = approximately $80/kW-year.

Financial Benefit from Distribution Upgrade Deferral

Before actually describing the financials associated with T&D deferral, Bidders should note that the description of the process for estimating benefits (below) is made without regard to the type of EES used or to EES equipment and operation cost. It is up to Bidders to estimate costs associated with EES plants needed to make the deferral possible.

Furthermore, calculations shown below are made as if the EES plant being considered has the necessary power output and discharge duration. Though it may be obvious, system designers/integrators must design a EES plant with the necessary power output and discharge duration needed to serve the projected load growth. (The “sizing” process is summarized above).

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

Assuming that the EES plant has enough power output and 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 only 225 kW of EES 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 EES is:
$150,000 / 225 $kW_{storage}$ = $666 / $kW_{storage}$.

If the EES 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 EES 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 / $kW_{storage}$.

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 is assumed to be deferrable. It is a high voltage line to extend from Southern to Northern California. It is referred to as Path 15. The existing load carrying capacity is about 3,900 MW and the upgrade has an estimated cost of ~$500 Million.[13]

Assuming a load growth rate of 2.5%/year, the 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 EES 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 EES to defer the transmission project is \$65 Million/100 $MW_{storage}$ = \$650/$kW_{storage}$.

Bidders may want to learn more about PIER's perspective on T&D R&D needs in California. That information is available at http://www.energy.ca.gov/pier/strat/strat_research_trans6.html.[14]

Multi-Year Deferrals

If EES is used to defer an upgrade for more than one year the same evaluation described above (estimating EES capacity requirements, single year EES deferral benefit, and EES discharge duration) is undertaken to determine whether the next year of deferral is cost-effective.

If EES *is* used to defer a specific upgrade for more than one year, EES that was added in previous years must remain in place. That is, EES capacity used for deferral in subsequent years is added to the existing EES capacity, 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 EES can remain in place (for arbitrage) or it could be moved to another location for additional capacity benefits, as described in the next section.

EES Redeployment and Portability

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

Even if this is done just once in the ten year life of the EES plant, the effect on EES' cost effectiveness can be dramatic. In the example above, EES provides a one year deferral benefit of $666/kW of EES. So EES 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, EES could also be used to address different winter and summer T&D deferral sites, in the same year.

Note that the cost to redeploy the EES system must be included in the mature cost for the system.

Benefit #3 T&D Support Benefits

Description

It is possible that use of EES could improve the performance of the T&D system. For any given location, to the extent that EES 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 Avoided Cost due to T&D Support

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

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

Table 6. T&D Support financial Benefits—Standard Assumption Values

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

*Benefits 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 3 occurrences over the life of the unit. This value does not account for time-value-of money.

[#] Based on an NPV factor of 7.17.

Based on these values the standard assumption value for lifecycle benefit from T&D support benefit is $169/kW.[1] [2] [6]

Benefit #4 Reduced Time-of-Use Energy Cost

Description

To reduce electricity end-users' time-of-use (TOU) energy cost, EES 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 EES. This benefit applies to commercial and industrial electricity end-users that qualify for TOU energy prices; TOU prices 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. The general intent of 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, EES 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.

The prevailing energy price is shown relative to the hour of the day, for the A-6 tariff, in Figure 14 below, for the summer billing period of May to October. During winter months (November to April) there is no on-peak price period (i.e.; the mid-peak price applies during the entire day).

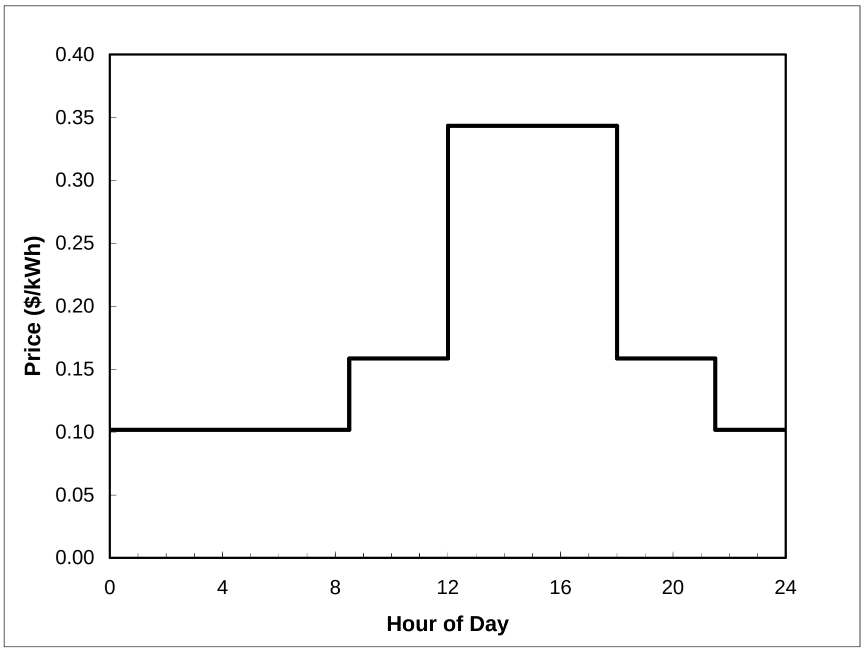

Figure14. Time-specific Price for Electricity – A6 Tariff, Summer

Time-of-use electricity prices are:

Period	Time-of-day	Price
Partial-peak	8:30 A.M. to 12:00 P.M.	15¢/kWh
On-peak	12:00 P.M. to 6:00 P.M.	32¢/kWh
Partial-peak	6:00 P.M. to 9:30 P.M.	15¢/kWh
Off-peak	9:30 P.M. to 8:30 A.M.	10¢/kWh

Estimating Reduced Time-of-Use Energy Cost

There are 720 hours per year during which the on-peak energy price applies. A EES 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 EES system, the cost to charge the EES 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 EES could have a discharge duration that is less than the duration of the on-peak price period. If, for example, a two hour EES plant is used then the annual benefit is:
2 hours/6 hours * $140/kW-year
= .33 * $140/kW-year
= $46.2/kW-year

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

Note also that the benefit estimation illustrated above does not account for variable maintenance cost incurred as the EES plant is used (including overhauls and subsystem replacement, as applicable). Those costs are part of the Bidder's estimate of the total cost for mature EES plants like those being demonstrated.

Benefit #5 Reduced Demand Charges

Description

Reduced demand charges are possible when EES 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, EES 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 EES.

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 Time-of-Use Energy and Demand Charges tariff. It applies to commercial and industrial end-users with peak load that exceeds 500 kW.

Figure 15 below shows diurnal demand (on the grid) with and without EES used to reduce demand charges, for an industrial facility with a constant electric load of 1 MW. The dashed line indicates that the EES plant serves all load for the six hours during which demand charges apply and that the EES plant charges for 7.5 hours at night when demand charges do not apply.

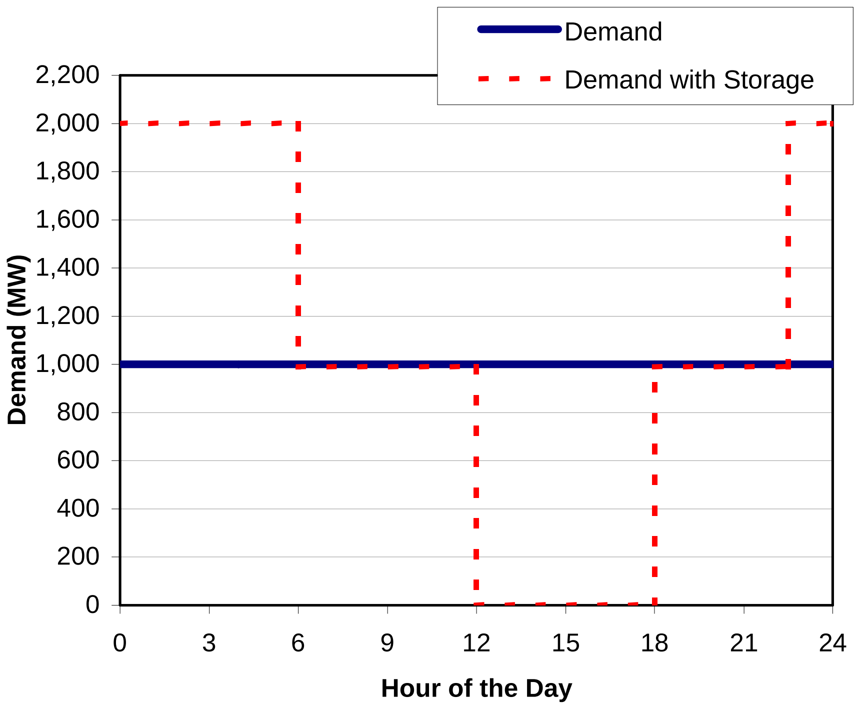

Figure 15. Constant Demand and Demand with Storage used to Reduce Demand Charges

It is very important to note that demand charges are applied rigorously, on a monthly basis. The implications are that if the EES 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. Bidders should take that into account when considering related effects associated with EES system 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 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.)

Assuming a EES 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 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/kW-month
= $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 NPV factor of 7.17 so the annual value translates to a lifecycle benefit of $465/kW-year.

The total partial peak demand charge reduction (benefit) is:
($3.70/kW-month – $2.55/kW-month) * 6 months/year
= $1.15/kW-month * 6 months/year
= $6.9/kW-year

For a ten year life, the net present value is:
7.17 * $6.9/kW-year
= $49.5/kW

Of course, there are also energy implications of this operation. Most tariffs 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 EES.

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 A.M. to 12:00 P.M.	11¢/kWh
On-peak	12:00 P.M. to 6:00 P.M.	19¢/kWh
Partial-peak	6:00 P.M. to 9:30 P.M.	11¢/kWh
Off-peak	9:30 P.M. to 8:30 A.M.	9¢/kWh

There are 720 hours per year during which the on-peak energy price applies. A EES 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 EES system the cost to charge the EES plant (for 720 hours of discharge) using low-priced, off-peak energy priced at 9¢/kWh is:
10¢/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-year + $401/kW
= $866/kW.

Benefit #6 Reduced Reliability-related Financial Losses

Description

Benefits associated with improved electric service reliability accrue if EES reduces financial losses associated with power outages. This benefit is 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 approaches suggested below yield benefits that are somewhat generic. Bidders may suggest and document an approach that provides specific reliability benefits (e.g., for a specific type of end-user).

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. For the RFP, a value-of-service of $20/kWh is recommended.[16]

To calculate annual reliability benefit, the standard assumption total 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 NPV 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 EES is used.

Based on a survey of existing research and known data related to electric service reliability, a generic value of $10/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 EES 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 NPV factor of 7.17 leads to a lifecycle benefit of $359/kW.

Benefit #7 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.

EES 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-EES system would be able to provide firm power when needed, using renewable energy. Note that, in many cases generation need only provide power for 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 EES is used (in conjunction with wind generation) is the financial benefit associated with renewables capacity firming.

The calculation below assumes that the EES 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 EES 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 = $13/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 .3 (30%). So capacity firming can provide benefits equal to 70% (1 - .3) 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

If the lower cost peaker is 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.

Benefit #8 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.)

EES 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) EES owners can sell the energy for a large premium.

This benefit is distinct from that for renewables capacity firming: in the most fundamental terms capacity firming is done to avoid the need for generation equipment 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 an EES plant whose nameplate output is equal to the wind generation plant's output. The EES plant operation is like load-following in reverse: the EES plant "fills in" during peak demand periods such that a constant level of power is provided. At some times the EES is providing most of the energy, and at other times the EES 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 ten 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 A.M. to 12:00 P.M.	8.6¢/kWh
On-peak	12:00 P.M. to 6:00 P.M.	33.3¢/kWh
Mid-peak	6:00 P.M. to 11:00 P.M.	8.6¢/kWh
Off-peak	11:00 P.M. to 8:00 A.M.	4.6¢/kWh

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

Two factors are worth noting:

- 30% of wind generation (energy output) occurs during the on-peak price period without EES – 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 hour 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 EES to wind generation.

First the number of hours per day (during peak price periods) that the EES must discharge is calculated as follows. Assuming that the EES 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 NPV 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 EES was sold real-time to the grid. From above, the average price for that energy is 6.6¢/kWh. For an 80% efficient EES plant to discharge for 365 hours per year it must charge for 365/.8 = 456 hours per year.

If that energy is sold real-time (rather than using it to charge EES) 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 EES is:
$871/kW - $216/kW
=$655/kW

Note that the foregoing discussion of benefits does not account for related variable costs. Those must be addressed in cost estimates for mature plants used like the system to be demonstrated.

Benefit #9 Avoided Central Generation Capacity Cost

Description

For areas where the supply of electric generation capacity is tight, EES 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 EES used for this application.

Estimating Avoided Central Generation Capacity Cost

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.

If a credible case can be made for a generation capacity benefit from EES that is separate from energy related benefits then the Bidder will need a rationale for estimating the financial benefit.

For California 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. Applying a fixed charge rate of 0.13 yields an annual cost of $65/kW-year. Applying the NPV factor of 7.17 the lifecycle benefits (for a EES plant used for ten years) are:
$65/kW-year * 7.17
= $466/kW

Arguably this is the maximum possible value. For EES plants to provide that much benefit they must operate in such a way that they actually offset 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 not meet air emission requirements if they must operate for more than a very small portion of the year.)

Applying the NPV factor of 7.17 the lifecycle benefits (for a EES 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, probably at the wholesale level. If applicable, electric supply capacity prices could be used to estimate this benefit.

However this benefit is estimated, Bidders should provide a credible rationale for the assumptions and approach used.

Benefit #10 Ancillary Services

Description

It is well known that EES 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 familiar services are spinning reserve and load following.

Estimating Benefits of Ancillary Services

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 determine 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 EES, the amount of ancillary benefits that may be realized is affected by discharge duration.

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

Applying the 7.17 NPV factor, the lifecycle benefits are an estimated $71.7/kW.

Benefit #11 Avoided Transmission Access Charges

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.

Also, in many areas transmission capacity additions are not keeping pace with electric peak demand growth. Results include: 1) transmission systems that are becoming congested during periods of peak demand, and 2) increasing transmission access and congestion costs and charges.

Storage could be used to avoid those 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.

Estimating Avoided Transmission Access Charges

Benefits associated with avoided transmission access charges cannot be generalized. They depend on, among other factors, EES discharge duration, location, time-of-year and time-of-day. Furthermore, in California the marketplace for transmission capacity is just taking shape.

A standard assumption value of $10/kW-year is used.[11] Applying the 7.17 NPV factor, the lifecycle benefits are an estimated $71.7/kW.

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

Benefit #12 Reduced PQ-related Financial Losses

Description

This benefit is 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 (PQ) are well documented. Technical details are not covered herein.

In the most general terms PQ-related financial benefits accrue if EES 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 EES 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 EES 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 EES plant for improved PQ is $30/kW-year.

For this RFP, total lifecycle benefits from PQ may not exceed 30% of total benefits associated with a specific demonstration. Likewise, total lifecycle benefits from PQ for a mature/commercial plant may not exceed 30% of total mature benefits.

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 EES 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 RFP. Also based on the same information, the standard assumption value for the annual number of events is 20.[8] [9]

The result is that EES 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, provides an annual benefit of $100/kW-year.

After multiplying by the NPV 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.

Benefit #13 Incidental Energy Benefits

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

For this RFP, when EES 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 application and situation-specific.

Perhaps the most extreme example is EES used for T&D support. Assuming total discharge duration of five seconds, the EES 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 EES plant rated output.)

In that case it is not worth calculating the incidental energy benefit. However, if EES 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 16 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. An EES 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 EES 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:
$.18/kWh * 20 hours per year
= $3.6/kW-year

The lifecycle benefit is:
$3.6/kW-year * 7.17
= $26/kW

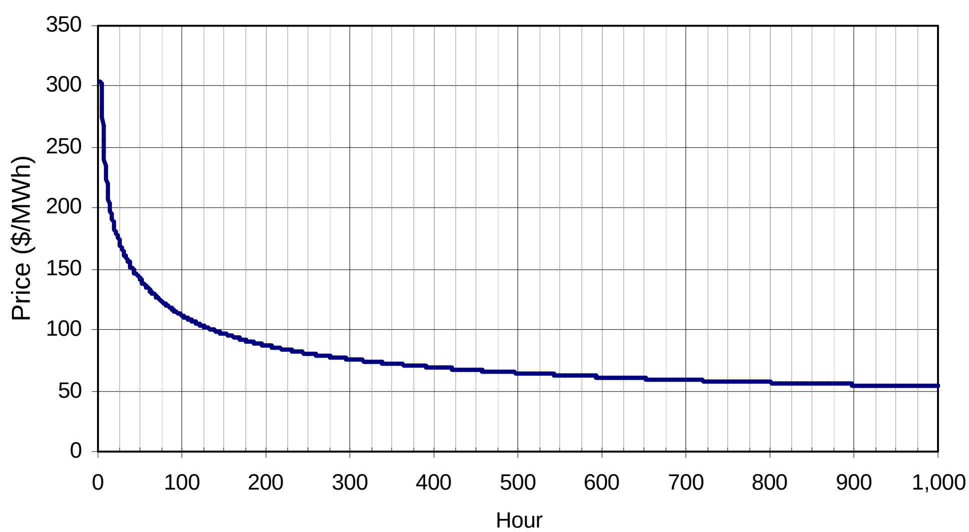

Figure 16. Running Average Energy Price ($2003), 1,000 Hours

However, if energy production does not correspond with times when electric energy price is high, then the Bidder must establish the benefit using a credible rationale such as using the average price during the times when incidental energy is discharged.

Tariff-based

If incidental energy is provided by an EES 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.

That is, the tariff that specifies the demand charge (units are $/kW-month) also specifies the corresponding energy prices. For example, the PG&E E19 tariff specifies an on-peak summer energy price of 19¢/kWh.

From the report subsection above entitled Benefit #5 Reduced Demand Charges, 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 EES for benefits to exceed cost. Bidders must provide a rational for combining benefits.

Operational Conflicts

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

So, when estimating combined benefits it is important that Bidders not add benefits from applications with conflicting operational needs.

Technical Conflicts

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

Another example is EES 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 T&D support or end-user PQ benefits.

Consider also EES system reliability. Less reliable (though lower cost) EES 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.

<u>Market Intersections</u>

As described in Section 4 of this attachment and as illustrated in Figure 17, Bidders must consider how combining benefits may affect (reduce) the maximum market estimates.

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

- Technical market potential is 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.

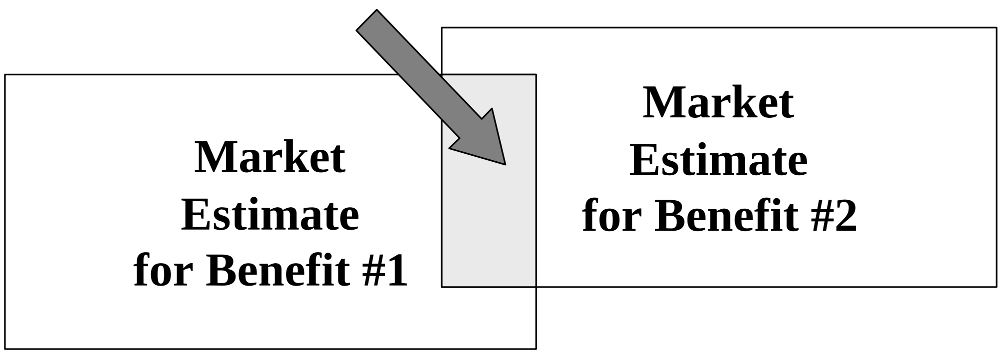

Figure 17. Market Estimation for Combined Applications/Benefits: Market Intersection

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 EES used to provide T&D deferral benefits can also provide arbitrage related benefits. Even if EES 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 18 shows load and energy price implications for operation of an EES plant for the combined benefits of demand charge reduction and time-of-use energy cost reduction.

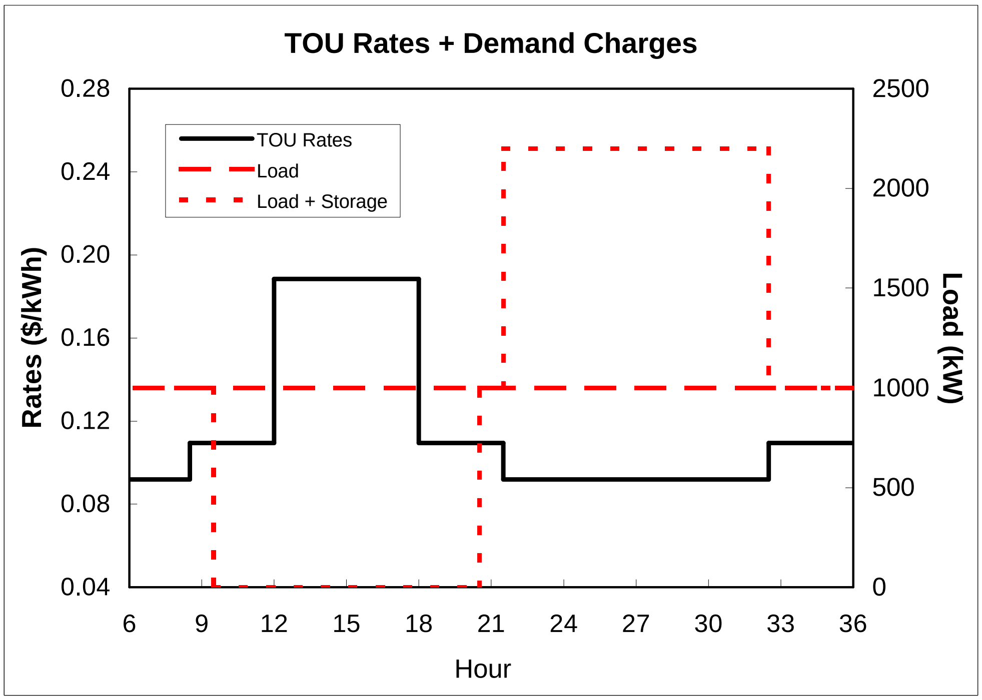

Figure 18. Demand Charge Reduction Based on PG&E's E19 Rate

For details about how to calculate the total benefits associated with EES operation for these two complimentary benefits, please see the discussion of demand charge reduction benefits in Section 4 of this attachment. 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 EES 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 EES plant.

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

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

End Notes

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[2] Torre, William V., DeSteese, J.G., Dagle, J.E., Evaluation of Superconducting Magnetic Energy Storage for San Diego Gas and Electric. Electric Power Research Institute. EPRI Report # 106286 2572-14, August 1997.

[3] California Energy Commission. January 28, 2003. *2003 California Electricity Supply – Peak Demand Balance (MW) On First of The Month*.

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[5] Randy Abernathy, Vice President, Market Services, California Independent System Operator. Presentation. 2002. *Wind Energy in the California Market.*

[6] Eckroad, Steven. Electric Power Research Institute. Personal communication with Joe Iannucci. June 2003.

[7] Pupp, Roger. March 24, 2003. *Distribution Cost Percentiles.* Communication by e-mail message with Jim Eyer, Distributed Utility Associates.

[8] Eto, Joseph, et. al. Lawrence Berkeley National Laboratory. Prepared for the Electric Power Research Institute and the U.S. Department of Energy. Coordinated by the Consortium for Electric Reliability Technology Solutions. June 2001. *Scoping Study on Trends in the Economic Value of Electricity Reliability to the U.S. Economy*. LBNL Report #47911; and private communications between Joseph Eto and Joseph Iannucci, March and April 2003.

[9] [a]Sullivan, Michael J., Vardell, Terry, Johnson, Mark. November/December 1997. *Power Interruption Costs to Industrial and Commercial Consumers of Electricity.* IEEE Transactions on Industry Applications. [b] Sullivan, Michael J., Vardell, Terry, Suddeth, Noland B., and Vojdani, Ali. IEEE Transactions on Power Systems. Vol. 11, No. 2. May, 1996. *Interruption Costs, Customer Satisfaction and Expectations for Service Reliability*.

[10] Electric Power Research Institute. Evaluation of SMES for San Diego Gas and Electric. August 1997. EPRI Report TR106286.

[11] Standard assumption values for the Avoided Transmission Congestion Charges and T&D support applications and standard assumption values for benefits that are not listed as applications (Avoided Cost for Central Generation

Capacity, Ancillary Services, and Avoided Transmission Access Charges) are "placeholder" values.

Bidders may provide alternate estimates for these standard assumption values though the rationale and assumptions used must have credible bases. Examples include letters from the California ISO or a utility, contracts to provide ancillary services with the California ISO or a utility, engineering calculations from a knowledgeable P.E., applicable information for systems outside of California, or credible simulation results.

One possible resource is the Federal Energy Regulatory Commission (FERC) http://www.ferc.gov/

Additional information may be available at the website for the California Independent System Operator (ISO) at http://www.caiso.com/

[12] California Energy Commission. November 2002. Forecast of Marginal Energy Prices, for each hour of the year, for 2004. Developed based on the hourly profile from 1999 PX Day-Ahead prices and on projected prices for "typical days" in each season using the Prosym model. Contact: Joel Klein

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[14] California Energy Commission R&D Committee Workshop to Develop a Five-Year Transmission R&D Plan. Sponsored by the Commission's Public Interest Energy Research (PIER) Program. Wednesday, March 12, 2003. Transcript of proceedings, reports and presentations are available at: http://www.energy.ca.gov/pier/strat/strat_research_trans6.html

[15] Iannucci, Joseph. Private communication with Lloyd Cibulka, P.E. April 17th, 2003.

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