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Methodology to Determine the Technical Performance and Value Proposition for Grid-Scale Energy Storage Systems

A Study for the DOE Energy Storage Systems Program

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Abstract

As the amount of renewable generation increases, the inherent variability of wind and photovoltaic systems must be addressed in order to ensure the continued safe and reliable operation of the nation's electricity grid. Grid-scale energy storage systems are uniquely suited to address the variability of renewable generation and to provide other valuable grid services. The goal of this report is to quantify the technical performance required to provide different grid benefits and to specify the proper techniques for estimating the value of grid-scale energy storage systems.

Acknowledgments

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Matt Donnelly and Dan Trudnowski developed the materials for the technical performance chapter. Verne Loose developed the material for the economic analysis chapter. Dhruv Bhatnagar developed Table 3.2. Anthony Menicucci created many of the block diagrams in the technical performance chapter and researched the information in Table 1.1. Ray Byrne served as the Sandia project lead.

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Acronyms, abbreviations, and definitions

Adequacy The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Area Control Error (ACE) The North American bulk power grid is divided into many regional control areas, or balancing authorities. These balancing authorities are charged with maintaining a predetermined schedule of power imports and exports, as well as responding in a coordinated fashion to grid frequency deviations. ACE is a measure of the balancing authority's effectiveness in achieving these goals. ACE is used to implement AGC for the generators within the control area. See [7].

Automatic Generation Control (AGC) Some generators within a region of an interconnected power grid are charged with reacting to imbalances between supply and demand on a continuing basis. AGC is a control system used to deliver commands to generators under AGC control to either increase or decrease real power output. See [7].

Available Transmission Capacity (ATC) Generators wishing to connect to an operating bulk power grid must first find a path for the power they wish to generate from the point of generation to the ultimate buyer of the energy. ATC is a measure of the amount of capacity available on a given section of the transmission grid. It is used by various parties to help broker transmission contracts. ATC is often found on the OASIS site hosted by the relevant grid operator. See [7].

Data Acquisition (DAQ) DAQ is a general term used to refer to any kind of instrumentation used to collect data. The term "DAQ" often refers to the front-end of a continuous data collection system. The back-end of the data collection system would then perform analysis and archiving of the data. In this report, DAQ is contrasted to "Data Logging" by way of typical sample rates. It is implied that a DAQ system has a faster sample rate than a logger. This definition is by no means an industry standard.

Data Logger Data logger is a general term used to refer to any kind of instrumentation that contains an on-board memory system. A data logger stores the data it collects for future download by the user. In this report, "Data Logger" is contrasted to DAQ by way of typical sample rates. It is implied that a DAQ system has a faster sample rate than a logger. This definition is by no means an industry standard.

Financial Transmission Right (FTR) A financial transmission right is a financial instrument that entitles the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path in a particular market (e.g. the day ahead market).

Governor or Speed Governor A governor is a control device used to regulate the power delivered by a source of energy such as a generator. The governor acts on the speed of the generator (the feedback signal) to regulate, or throttle, the input energy to the generator. In the context of this report, a discussion of governors is useful when assessing the benefit that storage technologies may provide for bulk power grid frequency regulation.

Independent System Operator (ISO) An ISO is charged with operating the bulk power grid for reliability. The ISO is "independent" because it does not own any transmission or generation assets. Not every region of the North American grid is overseen by an ISO, however every region is operated by a central oversight authority. A discussion of the ISO is prudent in this report because the regional ISOs are data providers, through the respective OASIS systems, for much of North America. Where an ISO is not present, it is usually possible to retrieve OASIS data from the relevant grid operating entity.

Open-Access Same-Time Information System (OASIS) In response to the Energy Policy Act of 1992, grid operators established an information system intended for use by entities wishing to use parts of the bulk transmission system. OASIS systems contain information on system loading, transmission capacity, and other data intended to level the playing field for all parties interested in access to the bulk transmission system. OASIS systems are normally web-based and are operated by ISOs or other regional operating entities. In the context of this report, OASIS systems are expected to be rich sources of data that can be used for benefit analysis.

Phasor Measurement Unit (PMU) PMU has become a generic term for a DAQ system capable of measuring time synchronized positive sequence voltages and currents. Time synchronization refers to the use of GPS (global positioning system) timing to accurately time-tag samples from a DAQ. For some of the transmission-related benefit analyses, it is important to obtain time synchronized data samples.

$\boldsymbol{P}$, $\boldsymbol{Q}$, $\boldsymbol{V}$, $\boldsymbol{I}$, $\boldsymbol{f}$ The physical quantities associated with producing, delivering and consuming electricity (alternating current). V refers to the voltage at a point in the system. I refers to the current passing through a point in the system. Voltage and current have two components: magnitude and angle. When measuring V and I it is assumed that only magnitude is of interest at sample rates of 1 *sps* (sample per second) or slower. (This is a generalization for purposes of simplifying monitoring requirements. It is not a generally accepted industry norm.) When measuring faster than 1 *sps* both magnitude and angle are of interest. Some data acquisition systems, such as a PMU, may provide "positive sequence" voltage and/or current. For simplicity within this report, the positive sequence can be assumed to be equal to any single phase of a 3-phase system. P is the real power passing through a point in the system, and Q is the reactive power passing through a point in the system. Frequency, f, is the frequency of the positive sequence voltage or, for simplicity, the frequency of the voltage in any phase of a 3-phase system.

Power Factor (PF) A measure of the amount of real power in proportion to apparent power. A PF of 1.0 indicates that all of the current passing through this point in the system is "in phase" with the voltage at this point in the system. It is beneficial to operate the bulk power system at a PF near unity, and power factor correction is the act of increasing the power factor at a selected point in the system.

Power Quality (PQ) Monitor A PQ monitor, in the context of this report, is a data acquisition system that samples "point-on-wave" data at a relatively high sample rate. In the context of this report, a PQ monitor is the only data acquisition system that samples point-on-wave data as opposed to root mean square (*rms*) values of voltage and current acquired by other monitoring technologies. Acquiring point-on-wave data demands very large storage capabilities, and therefore PQ monitors do not normally offer continuous recording. Rather, a PQ monitor samples continuously but only records data when there is a disturbance or abnormality detected.

Root Mean Square (RMS) The square root of the mean of the squares of the signal. For a discrete signal, $\boldsymbol{x} = \{x_1,\ x_2,\ x_3,\ \ldots, x_n\}$, the *rms* value is given by:

$$x_{rms} = \sqrt{\frac{1}{n}\left(x_1^2 + x_2^2 + x_3^2 + \ldots + x_n^2\right)}$$

For a continuous time signal, $f(t)$, defined over the interval $T_1 \leq t \leq T_2$, the *rms* value is given by:

$$f_{rms} = \sqrt{\frac{1}{T_2 - T_1}\int_{T_1}^{T_2} [f(t)]^2 dt}$$

For a sinusoidal signal with amplitude A, the *rms* value is $A/\sqrt{2}$.

Sample Rate (SPS) The sample rate of a data acquisition system is expressed herein as the number of samples collected per second (samples per second = *sps*). For some of the slower benefits assessed, sample rate is expressed as a fraction of a sps. For example, 1/60 *sps* specifies a data acquisition system that samples once per minute. We chose to present everything in *sps* to avoid confusion.

Supervisory Control and Data Acquisition (SCADA) A computer control system that monitors and controls an industrial process. Power generation is an example of an industrial process.

State of Charge (*SoC*) The state of charge (*SoC*) of the energy storage device, usually expressed as a percent of the full capacity (for example, 50%) or as a quantity of energy (for example, 1 MWh) that is available to discharge.

Western Electricity Coordinating Council (WECC) The Western Electricity Coordinating Council (WECC) is the Regional Entity responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection.

Chapter 1

Introduction

1.1 Introduction

The American Recovery and Reinvestment Act of 2009 (Recovery Act) provided the U.S. Department of Energy (DOE) with about $4.5 billion to modernize the electric power grid. The two largest initiatives resulting from this funding are the Smart Grid Investment Grant (SGIG) program and the Smart Grid Demonstration program (SGDP). These programs were originally authorized by Title XIII of the Energy Independence and Security Act of 2007 (EISA), and later modified by the Recovery Act. DOE's Office of Electricity Delivery and Energy Reliability (OE) is responsible for implementing and managing these 5-year programs.

The SGDP is authorized by the EISA Section 1304 as amended by the Recovery Act to demonstrate how a suite of existing and emerging smart grid technologies can be innovatively applied and integrated to prove technical, operational, and business-model feasibility. The aim is to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve on the ones commonly used today. SGDP projects were selected through a merit-based solicitation in which DOE provides financial assistance of up to one-half of the project's cost. SGDP projects are cooperative agreements while SGIG projects are grants.

The SGDP effort consists of 32 projects. Of these, 16 projects are focused on regional smart grid demonstrations and 16 are focused on energy storage demonstrations (see Table 1.1). The total value of SGDP projects is about $1.6 billion. The federal portion is about $600 million. The Smart Grid Energy Storage Demonstration Projects are being managed by the National Energy Technology Laboratory (NETL) for the DOE Office of Electricity Delivery and Energy Reliability. A list of the energy storage demonstration projects appears in Table 1.1.

The goal of this document is to identify methodologies for evaluating the technical and financial performance of the Smart Grid Energy Storage Demonstration Projects. In cases where there might be several approaches, for example an in-depth analysis versus a quick-approximation, we try to present both methods along with a discussion of the relative benefits of each approach. This document has two main sections: technical performance validation and economic performance analysis. The technical performance section includes analysis of operability, storage system parameters (for example, maximum/minimum charge and discharge rate, round-trip efficiency, storage capacity, and controllability), as well as tests for identifying system parameters. The economic analysis section looks at as-built costs and recoverable revenue to calculate investment criteria as well as non-recoverable broad-based societal benefits (for example, lower electricity rates in a region, reduced emissions, etc). As a supplement to this document, the Navigant Energy Storage Computational Tool implements some of the methods presented in this report. In addition, MATLAB® tools

Table 1.1: Summary of ARRA storage demonstration project goals.

	44 Tech Inc. (Aquion Energy)*	Amber Kinetics*	Beacon Power	City of Painesville	Duke Energy Business Services, LLC	East Penn Manufacturing Co.	Ktech Corporation	New York State Electric & Gas Corporation	Pacific Gas & Electric Company	Premium Power Corporation	Primus Power Corporation	Public Service Company of New Mexico	Seeo, Inc.*	Southern California Edison Company	SustainX, Inc.*	The Detroit Edison Company
TECHNOLOGY	Na-ion (New)	Flywheel (New)	Flywheel (Beacon)	Flow (New)	Advanced Lead Acid (Xtreme)	Advanced Lead Acid (East Penn)	Flow (New)	CAES	CAES	Flow (Premium)	Flow (Primus)	Advanced Lead Acid (East Penn)	Li-ion (New)	Li-ion (A123)	CAES	Li-ion (A123)
Electric Energy Time Shift	NO	YES	NO	YES	YES	NO	YES	YES	YES	YES	YES	YES	NO	YES	NO	YES
Electric Supply Capacity	NO	NO	NO	YES	NO	NO	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO
Load Following	NO	YES	YES	YES	NO	YES	NO	YES	YES	NO	NO	NO	NO	NO	NO	YES
Area Regulation	NO	YES	YES	NO	YES	YES	NO	YES	YES	NO	NO	NO	NO	NO	NO	YES
Electric Supply Reserve Capacity	NO	NO	NO	YES	NO	NO	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO
Voltage Support	NO	NO	YES	NO	NO	NO	NO	YES	YES	NO	NO	YES	NO	NO	NO	YES
Transmission Support	NO	NO	NO	NO	NO	NO	NO	YES	YES	YES	NO	NO	NO	YES	NO	NO
Transmission Congestion Relief	NO	NO	NO	YES	NO	NO	NO	YES	YES	YES	NO	NO	NO	YES	NO	NO
T&D Upgrade Deferral	NO	YES	NO	NO	NO	NO	NO	YES	YES	NO	NO	YES	NO	YES	NO	NO
Substation Onsite Power	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Time-of-Use Energy Cost Management	NO	NO	NO	NO	NO	NO	YES	NO	NO	YES	NO	NO	NO	NO	NO	NO
Demand Charge Management	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO	NO
Electric Service Reliability	NO	NO	NO	YES	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO	YES
Electric Service Power Quality	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES
Renewables Energy Time Shift	NO	NO	NO	NO	YES	NO	YES	YES	YES	YES	YES	YES	NO	YES	NO	YES
Renewables Capacity Firming	NO	NO	YES	NO	YES	NO	NO	YES	YES	NO	YES	YES	NO	YES	NO	YES
Wind Generation, Grid Integration, Short Duration (= 15 min)	NO	NO	YES	NO	YES	NO	NO	YES	YES	NO	YES	NO	NO	YES	NO	NO
Wind Generation, Grid Integration, Long Duration (> 15 min)	NO	NO	NO	NO	YES	NO	NO	YES	YES	NO	YES	NO	NO	YES	NO	NO

* No Grid connected demo

developed by Sandia National Laboratories are available for the more data-intensive algorithms. These tools may be found at www.sandia.gov/ess/tools.

The following sections contain some mathematical preliminaries for the technical performance and economic performance chapters.

1.2 Mathematical Preliminaries

1.2.1 Technical Performance Requirements

The data acquisition sampling rate requirements in Chapter 2 are largely driven by the ability to reconstruct the sampled signal. The Nyquist-Shannon sampling theorem states that if a signal $f(t)$ contains no frequencies higher than B Hz, it can be perfectly reconstructed using data points sampled at an interval of $1/2B$ (twice the highest bandwidth). One assumption of the theorem is that an infinite series of samples is available. This is not realistic for real-world applications. A practical rule of thumb is to sample between 4 and 10 times the highest bandwidth signal. Examples of different sampling rates relative to the signal bandwidth are shown in Figure 1.1. While sampling at a higher rate makes signal reconstruction easier, the penalty is the increased amount of data that must be stored. Therefore, for experimental or proof-of-concept systems a much higher sampling rate is often employed to fully characterize the system performance. On the other hand, operational systems often have much lower sampling rates to reduce the data storage requirements.

The step response tests are motivated by linear systems theory. A complete discussion of linear systems theory is beyond the scope of this document. Good introductory references include [8, 9, 10, 11]. Usually one assumes that the system is causal, linear, and time-invariant. A system is causal if the output at time t is a function of the inputs up to time t. For a non-causal system, the output at time t would be a function of future inputs. A linear system is defined by the principle of superposition. Superposition includes two properties: additivity and scaling. Equation (1.1) illustrates the additivity property while Equation (1.2) shows the scaling property. The linear system is represented by the function $T\{\cdot\}$.

$$T\{x_1(t) + x_2(t)\} = T\{x_1(t)\} + T\{x_2(t)\} \tag{1.1}$$

$$T\{ax(t)\} = aT\{x(t)\} \tag{1.2}$$

The output of time-invariant systems do not depend explicitly on time. This is also equivalent to shift invariance. Given a system input, the output for a shifted input is the original output shifted.

$$\begin{array}{l}\text{given an input signal } x(t), \text{ that produces an output } y(t), \\ \text{the delayed signal } x(t+\delta), \text{ produces an output } y(t+\delta)\end{array} \tag{1.3}$$

A primary interest in evaluating the technical performance of electricity storage systems is characterization of the input-output behavior. A first-order approximation is often employed to approximate the input-output behavior of systems. The differential equation governing a first-order system is given by

$$\frac{dy}{dt} + ay - ku = 0 \tag{1.4}$$

where $y(t)$ is the system output and $u(t)$ is the system input. By taking the Laplace transform, the transfer function of the first order system becomes

$$y(s) = \frac{k}{s+a}u(s) \tag{1.5}$$

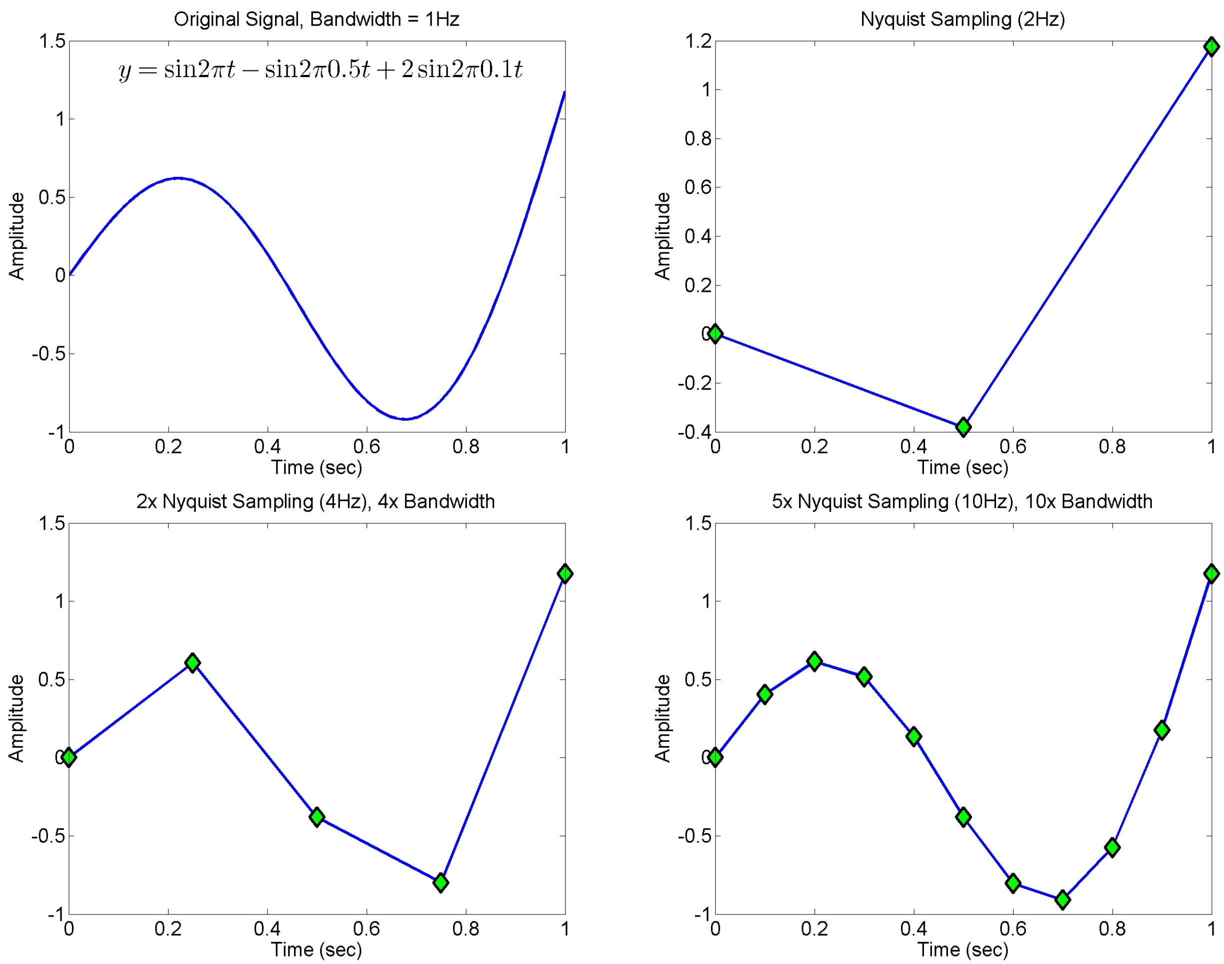


Figure 1.1: Data sampling rate requirements.

The step response of a first order system in the Laplace domain is

$$y(s) = \frac{k}{s(s+a)} \tag{1.6}$$

Taking the inverse Laplace transform yields the following time response

$$y(t) = \frac{k}{a}\left(1 - e^{-at}\right) \tag{1.7}$$

By taking step response data, one can apply various methods (e.g. least squares, etc.) to estimate the first order approximation of system parameters from test data. Higher order models can be applied if a first order model is insufficient to capture the dominant system dynamics. It is often common to fit a second order model given by

$$y(s) = \frac{\omega_n^2}{s^2 + 2\zeta\omega s + \omega_n^2} u(s) \tag{1.8}$$

Applying a step response input and taking the inverse Laplace transform yields the following time response.

$$y(t) = 1 - \frac{1}{\beta} e^{-\zeta\omega_n t} \sin(\omega_n \beta t + \theta), \text{ where } \beta = \sqrt{1-\zeta^2},\ \theta = \tan^{-1}\left(\frac{\beta}{\zeta}\right) \tag{1.9}$$

The transient response of a second order system is characterized by the damping ratio, ζ, which provides insight into the step response. For large values of ζ, the step response will be relatively slow with no overshoot. As ζ is decreased, the response becomes quicker. For $\zeta = 0.7$, the system will have a small overshoot. As ζ is decreased further, the response becomes quicker but more oscillatory. If ζ becomes zero, the response will be purely oscillatory. Negative values will result in an unstable system with growing oscillations. This behavior is illustrated in Figure 1.2.

Key step response parameters include:

- Rise time, T_r
- Peak time, T_p
- Settling time, T_s
- Percent overshoot, $P.O.$

Referring to Figure 1.3, the percent overshoot is defined as

$$\text{P.O.} = 100(M-1) \tag{1.10}$$

Note that in this figure, the output value has been scaled so that the steady state value is 1.0. The settling time, T_s, is the time required to settle within $+/-\delta$ of the final value. The peak time, T_p is the time required to reach the peak overshoot value. This parameter is not defined for well damped systems that do not have any overshoot. There are several common definitions of rise time, T_r. In this report, we recommend the time to reach 90% of the final value. Another common practice is to measure the time from 10% to 90% of the final value.

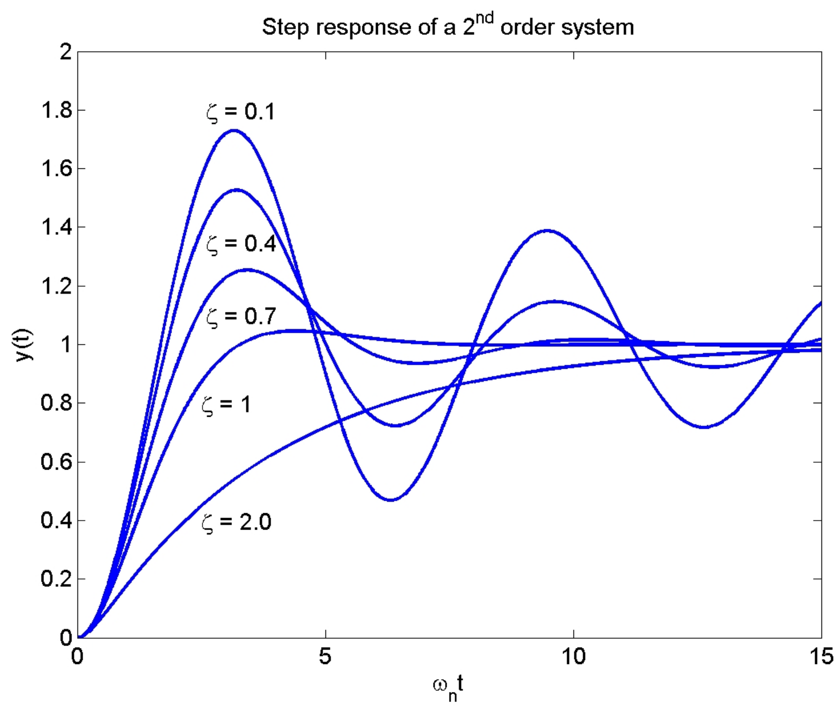


Figure 1.2: Step response of a 2^{nd} order system.

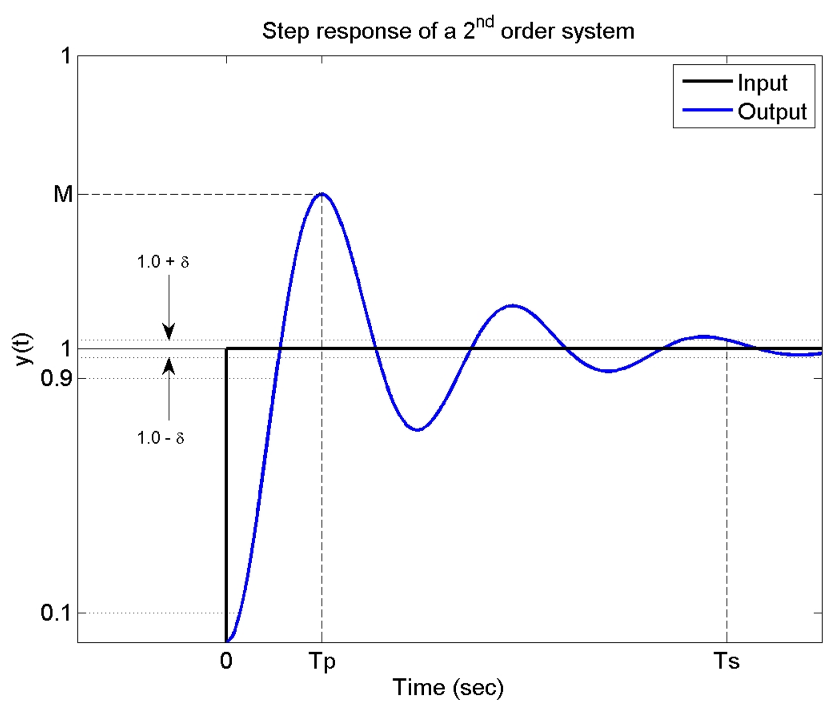


Figure 1.3: Step response parameters.

1.2.2 Financial Calculations

In this section, we present the mathematical preliminaries for the financial calculations employed in this report. Many of these calculations are typical engineering economic analysis [3].

Project evaluation is the process by which information is organized to consistently and objectively evaluate the economic merit of investments (the process of delaying current for future consumption) and is often referred to in the public sphere as *benefit-cost analysis* (B-C) and in the private sphere as *discounted cash flow* (DCF) analysis. The approaches are very similar though their main distinguishing feature is that the latter focuses on cash flows from the perspective of a private entity while the former likely also includes estimated benefits and costs that may not be reflected in explicit cash flows. The bottom line metric employed to determine whether the project should be undertaken is usually referred to as the investment criterion. A variety of such criteria are available but most typically are *net present value* (NPV) (alternatively present value of net benefits) or *benefit-cost ratio* (B/C) [1]. For a more detailed exposition of benefit-cost analysis and its relationship to discounted cash flow analysis see [1]. The following sections review the calculations for the time value of money, cost benefit analysis, and return on investment.

Time Value of Money

The so-called time value of money derives from a concept economists refer to as *time preference*. Human beings are somewhat myopic as evidenced by their preference for current consumption over future consumption; the rate at which this preference is expressed is referred to as the *rate of time preference* and probably has its basis in uncertainty of the future as perceived by humans.

Money is the equivalent of consumption since it provides the holder with command over consumption goods. If an individual expresses indifference between receiving \$1.00 now or \$1.05 one year from now, this individual's rate of time preference is 5% per annum. Individuals may each have different rates of time preference and, in a societal context, one can speak of the *social rate of time preference* as the collective preference of a society for present over future consumption. The social rate of time preference would be the rate at which society would judge long-lived projects that require the sacrifice of current consumption to provide greater consumption in the future.

Applying these concepts, the time value of money is the value of money at some date referenced to another date given the amount of interest earned over the time period. The choice of interest rate is dependent on the application. The Fisher equation estimates the relationship between nominal and real interest rates under inflation [12]. The nominal interest rate, i, is a function of the real interest rate, r, and the inflation rate, π.

$$1 + i = (1 + r)(1 + \pi) \tag{1.11}$$

$$i \approx r + \pi \tag{1.12}$$

The nominal interest rate is the market rate for a financial instrument. The interest rate employed is often the risk-free interest rate, which is the rate of return from an investment with no risk of financial loss. The interest rate on short-term government bonds is often used as a proxy for the risk-free rate. The real interest rate measures the purchasing power of interest receipts adjusted for inflation. When calculating the time value of money, a key question is what interest rate should be used. If the analysis is attempting to take into account the effects of inflation, one should use the nominal interest rate. This implies that one should make some effort to model inflation in the

[1] Others include internal rate of return, rate of return on investment, rate of return on assets, rate of return on equity. These are most often used in the private sector.

future. An alternative approach is to employ the real interest rate and to perform the analysis net of any price changes over time. A resource for identifying nominal and real interest rates is found in [13]. All of the analysis in this report will employ real interest rates for evaluating the time value of money.

If the real interest rate is 5% per year, \$100 invested today will be worth \$105 in 12 months. Likewise, if someone promises you a deposit of \$105 12 months from now, the value of that today is only \$100. There are two ways to define the interest rate: simple interest or compound interest [3]. Simple interest is computed on the original sum, as shown below:

$$\text{total interest earned} = P \times r \times n \tag{1.13}$$

where P is the original principal, r is the interest per period, and n is the number of periods. For a loan, the amount due at the end (the future payment F) is given by

$$F = P + Prn, \quad \text{or } F = P(1 + rn) \tag{1.14}$$

Compound interest is more prevalent than simple interest. Compound interest accrues on the current balance at the end of each period. The future value F of a present sum P is given by

$$F = P(1 + r)^n \tag{1.15}$$

where n is the number of periods. Likewise, the present sum P in terms of the future value F is

$$P = \frac{F}{(1 + r)^n} = F(1 + r)^{-n} \tag{1.16}$$

If the interest rate is defined with continuous compounding, the future value F at time T of a present sum P is given by

$$F = Pe^{rT} \tag{1.17}$$

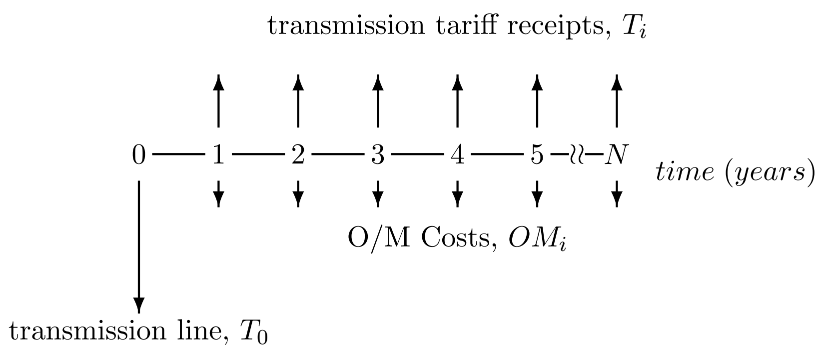
Likewise, the present value in terms of the future value is given by

$$P = Fe^{-rT} \tag{1.18}$$

When evaluating a potential stream of expenses and receipts over some period of time, the value of the payments and receipts must be referenced to some time in order to make a meaningful assessment. It is typical to bring every cash flow back to present value, or to the value at the end of the project, in which case it is a future value. An example of calculating the present value of a stream of receipts and expenses is shown in Figure 1.4. This approach is known as net present worth (PW) analysis or net present value (NPV) analysis.

Present Worth Analysis

Present worth analysis, often referred to as net present value (NPV) analysis, calculates the present value of all cash flows associated with a project. A negative cash flow is referred to as a disbursement or cost. A positive cash flow is referred to as a receipt or benefit. Cash flows are usually expressed in either table form or a cash flow diagram. An example of each appears in Figure 1.5. Net present value is often applied as a criterion to select between mutually exclusive alternatives, where the project with the highest NPV is selected. In cases where the benefits are the same for each project, it is sufficient to minimize the present worth of the costs. The present worth of the costs are often referred to as the total life cycle costs (TLCC). Similarly, for cases where the input costs are the same for each project, it is sufficient to maximize the present worth of the benefits.



$$NPV = -T_0 - \sum_{i=1}^{N} OM_i e^{-rt_i} + \sum_{i=1}^{N} T_i e^{-rt_i}$$

Figure 1.4: Time value of money example, valuation of a series of cash flows. Continuous compounding.

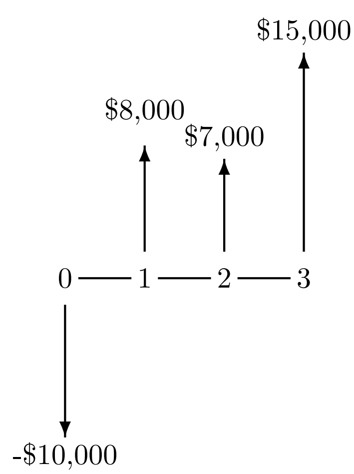
Benefit-Cost Analysis

When a regulated, investor-owned utility (IOU) wishes to invest in an energy storage device, public utility commissioners and their staffs should expect to receive an analysis of the investment in grid assets in the form of a private benefit-cost analysis of the investment. This analysis could take a variety of forms, depending upon the preferred analysis approach of the particular utility presenting the analysis. Nevertheless some key elements should be incorporated. Foremost, the important issue of the perspective of the analysis should be addressed. The commission should expect the regulated IOU to present an analysis from the perspective of their shareholders, with the analysis demonstrating that the investment adds to shareholder value. This would be a private benefit-cost analysis. As such, it would contain evaluations of only benefits and costs as viewed from the utility's perspective. Additional sales of electricity would be evaluated at the regulated rates for the utility, and costs would be accounted from the point of view of the utility. Because rates are regulated, the successful investment would be viewed as a reduction of costs compared to some alternative. This would involve an analysis of at least two alternatives: the "undertake the project" alternative and the "do not undertake the project" alternative.

With specific grid needs identified, and the EES technologies that can supply those needs also identified as described, a benefit-cost evaluation process can be applied. While it is not the purpose of this report to develop a complete description of all of the issues relevant to the development of a benefit-cost analysis of a private project, a high-level description of the important methodological issues is appropriate and thus provided.

Benefit-cost analysis applied in a private sector context is often referred to as discounted cash flow (DCF) analysis [1]. The methodological principles and techniques of the two approaches are virtually the same. The main difference is that the private analysis focuses exclusively on the revenue and cost (cash) flows that are estimated to result over the lifetime of the project

End of Year	Cash Flow
0	-$10,000
1	$8,000
2	$7,000
3	$15,000



$$NPV = -\$10,000 + \frac{\$8,000}{(1+r)} + \frac{\$7,000}{(1+r)^2} + \frac{\$15,000}{(1+r)^3}$$

Figure 1.5: Example cash flow table, cash flow diagram, and NPV calculation. Discrete compounding.

upon its implementation, and does not include public benefits and costs. Again, this is adopting the perspective of the investor in the EES system[2]. Additional analyses might accompany the investment proposal; for example, if the investor is the utility itself, it will also likely perform a revenue requirements analysis to demonstrate the likely impact of the investment on the need for or lack of need for retail electric rate adjustment. It is likely that a suite of analyses would support the proposal to the commission. A DCF/benefit-cost analysis to demonstrate positive net benefits over the long term, helping to support the capacity adequacy aspect; a revenue requirements analysis to demonstrate retail rate impact, if any; and a production cost modeling exercise to demonstrate operating cost-effectiveness. These are all likely components of the analysis suite.

It is possible that the commission or its staff will wish to extend this private benefit-cost analysis into a consideration of the public benefits and costs of the project. In that case, much of the relevant information about the project will already be available from the private analysis.

A schematic representing the process of reaching a decision using the application of benefit-cost analysis is contained in Figure 1.6. This figure represents the allocation of resources to one or the other of two projects where the right hand branch represents alternatives (including doing nothing). The do nothing alternative should always be present in project comparisons. Independence between the benefits and costs of the projects is normally assumed. In a particular application, if independence is not the case, then additional alternatives must be devised that are comprised of a combination of the interdependent projects. Incremental benefits and costs must then be calculated for the combined alternative. The effect of the process described in Figure 1.6 is to apply the economic concept of opportunity cost. If resources are assumed scarce, the cost of action A is the net revenue that could have been earned from applying the resources to action B instead. Other references on benefit-cost analysis include [14] and [3].

Benefit-cost analysis is a common method for evaluating competing projects using engineering economic analysis. The results are often stated as a benefit-cost ratio, as shown in equation (1.19). This approach is commonly used in public sector or quasi-public sector project evaluation. These cases may have a prevalence of externalities. Benefit-cost analysis is not prevalent in the private sector.

$$\text{Benefit-cost ratio} = \frac{B}{C} = \frac{\text{Present worth of benefit}}{\text{Present worth of costs}} \tag{1.19}$$

If the present worth (PW) of the benefits is larger than the present worth of the costs, then the B/C ratio is a positive quantity greater than 1.0. While it may seem intuitive to attempt to select the option with the maximum B/C ratio, this approach is only valid for two specific cases [3]. The appropriate B/C criteria for different situations are summarized in Table 1.2. It is important to note that an incremental benefit-cost analysis, which is required for mutually exclusive alternatives, is equivalent to maximizing the net present value (see Appendix B for a detailed explanation). An example of a benefit-cost analysis appears in Figure 1.7.

The perspective of the B/C analysis dictates the types of benefits included in the numerator. For private sector projects, the numerator usually includes only benefits that may be monetized by the entity undertaking the project. For example, an investor-funded power plant might not count reduced carbon emissions as a benefit unless it was monetizable via some sort of carbon credit, regardless of the benefit to the surrounding community. On the other hand, public sector projects often include all benefits and disbenefits that accrue to the public or the users of the facility in the numerator.

[2]The investor in an EES system proposed by a vertically integrated, regulated utility, (IOU) could be the utility itself, an independent power producer (IPP) proposing an EES investment the output of which is sold to the IOU, or a merchant plant.

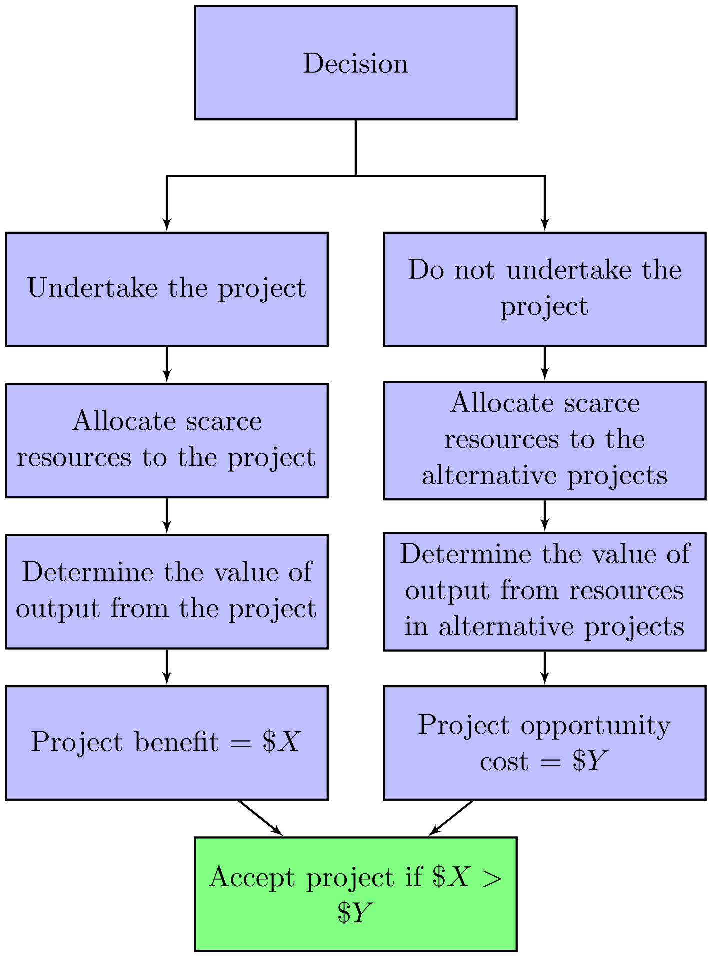
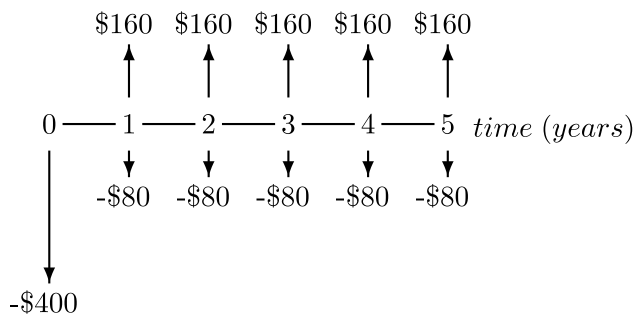


Figure 1.6: Benefit-cost analysis using the concept of opportunity cost [1].



Given the cash flow above for a hypothetical project and a 7% cost of capital, the present worth of the benefits is calculated as

$$\text{PW(B)} = \$160e^{-1(0.07)} + \$160e^{-2(0.07)} + \$160e^{-3(0.07)} + \$160e^{-4(0.07)} + \$160e^{-5(0.07)} = \$651.65$$

Similarly, the present worth of the costs is calculated as

$$\text{PW(C)} = \$400 + \$80e^{-1(0.07)} + \$80e^{-2(0.07)} + \$80e^{-3(0.07)} + \$80e^{-4(0.07)} + \$80e^{-5(0.07)} = \$725.82$$

The benefit-cost ratio is then calculated as

$$\text{Benefit-cost ratio} = \frac{\text{PW(B)}}{\text{PW(C)}} = \frac{\$651.65}{\$725.82} = 0.8978$$

Since the benefit-cost ratio is less than 1.0, the costs outweigh the benefits and it would not be worthwhile to undertake the project.

Figure 1.7: Benefit-cost analysis example.

Situation	Description	Criterion
Variable inputs and variable outputs	Inputs (e.g. money, etc.) and outputs (e.g. benefits) are variable.	*Two alternatives:* Compute the incremental benefit-cost ratio on the increment of investment between the alternatives. If $\Delta B/\Delta C \geq 1$, select the higher cost alternative; otherwise select the lower cost alternative.
Variable inputs and variable outputs	Inputs (e.g. money, etc.) and outputs (e.g. benefits) are variable.	*Three or more alternatives:* Solve by incremental benefit-cost ratio analysis.
Fixed input	Inputs (e.g. money, etc.) are fixed.	Maximize B/C.
Fixed output	Outputs (e.g. tasks, benefits, etc.) are fixed.	Maximize B/C.

Table 1.2: Benefit-cost analysis criteria for different scenarios [3].

Internal Rate of Return

Internal rate of return (IRR) is defined as the rate of return at which the present value of all cash flows is equal to zero [3]. When assessing the viability of a potential project, the internal rate of return is compared to a minimum attractive rate of return (MARR). If the projected internal rate of return is less than the MARR, the project is not worth pursuing. Like benefit-cost analysis, rate of return analysis can also be employed to evaluate different alternatives. When there are two options, an incremental rate of return (ΔIRR) is calculated on the difference between the alternatives. If the $\Delta IIR \geq MARR$, the higher cost alternative is selected. Otherwise, the lower cost alternative is selected. Figure 1.8 goes through an example rate of return calculation.

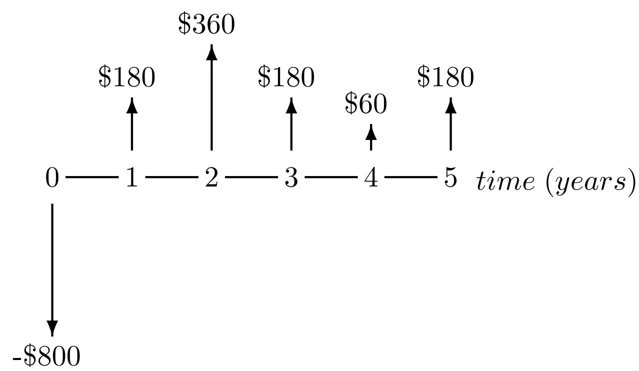
Levelized Cost of Energy

The levelized cost of energy (LCOE) is the cost assigned to every unit of energy produced (or saved) over the analysis period [6]. Thus, for each time interval corresponding to the unit of energy, the cost is equal to the LCOE times the quantity of energy. If each of these costs is discounted to present value, the total cost should equal the total life cycle cost (TLCC). This yields the equation for LCOE,

$$\sum_{i=1}^{N} \frac{Q_i \times \text{LCOE}}{(1+r)^i} = \text{TLCC} \tag{1.20}$$

where Q_i is the quantity of energy for period i, r is the interest rate for each period, and N is the number of periods. Similarly, the total life cycle cost is defined as

$$TLCC = \sum_{i=1}^{N} \frac{C_i}{(1+r)^i} \tag{1.21}$$



The internal rate of return is calculated by solving for the interest rate which makes the present worth of all cash flows equal to zero. For the cash flows shown above, the equation to solve is given by

$$0 = -\$800 + \$180e^{-r} + \$360e^{-2r} + \$180e^{-3r} + \$60e^{-4r} + \$180e^{-5r}$$

Solving for a closed-form solution is often very difficult, so internal rate of return calculations are usually solved with some sort of optimization routine, or by trial and error. Most financial software packages have tools for estimating internal rate of return. Solving the equation above, the internal rate of return is 6.95% for this example.

Figure 1.8: Internal rate of return example.

where C_i is the cost associated with period i. Combining these two equations and solving for $LCOE$ yields

$$LCOE = \frac{\displaystyle\sum_{i=1}^{N} \frac{C_i}{(1+r)^i}}{\displaystyle\sum_{i=1}^{N} \frac{Q_i}{(1+r)^i}} \tag{1.22}$$

Note that the quantity of energy Q_i is not being discounted, the discounting factor in the numerator and denominator are the result of combining equations (1.20) and (1.21).

1.3 Electricity Storage Model

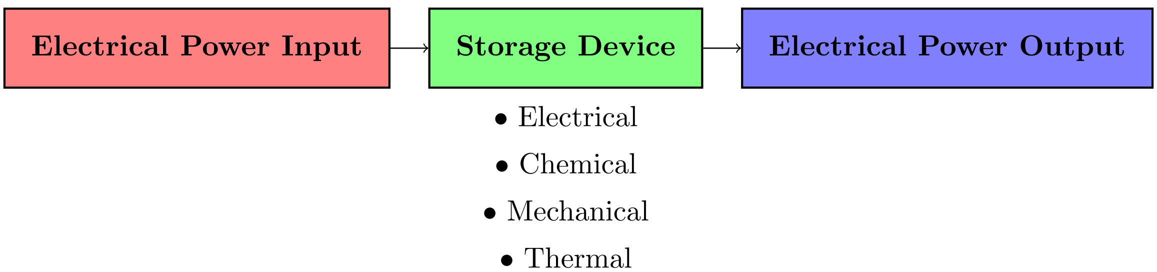


Figure 1.9: Electricity storage block diagram.

A block diagram representing an energy storage system is shown in Figure 1.9. The key parameters that characterize a storage device are:

- **Power Rating** [MW]: the maximum output power of the storage device. We assume that the maximum discharge and charge power ratings have the same amplitude.
- **Energy Capacity** [Joules or MWh]: the amount of energy that can be stored.
- **Efficiency** [percent]: the ratio of the energy discharged by the storage system divided by the energy input into the storage system. Efficiency can be broken down into two components: conversion efficiency and storage efficiency. Conversion efficiency describes the losses encountered when input power is stored in the system. Storage efficiency describes the time-based losses in a storage system.
- **Ramp Rate** [MW/min or percent nameplate power/min]: the ramp rate describes how quickly the storage device can change the state of charge or discharge.

In order to facilitate financial analysis of an energy storage system providing one or several grid services, a model of the system is required. A straightforward approach is to keep track of the energy stored at the end of each time interval. This yields the following model to track the state-of-charge:

$$S_t = S_{t-1} + \gamma_c q_t^c - q_t^d - \gamma_s S_{t-1}, \quad \text{(MWh)} \tag{1.23}$$

where

S_t	Energy stored at the end of time period t
S_{t-1}	Energy stored at the end of time period $t-1$
γ_c	Conversion efficiency (percent)
q_t^c	Quantity of energy pulled from the grid (charge) during time period t (MWh)
q_t^d	Quantity of energy provided to the grid (discharge) during time period t (MWh)
γ_s	Storage efficiency (percent)

The model is intuitive. The current energy level is a function of the charge and discharge quantities, the conversion efficiency, the energy level at the previous time step, and the energy losses over the time period. Additional parameters associated with the model are the length of the time period, the maximum charge/discharge quantities and the maximum storage capacity of the system. These quantities are defined as:

Δt	time period (for example, hours)
$\bar{q}^D$	maximum quanitity that can be sold/discharged in a single period (MWh)
$\bar{q}^R$	maximum quantity that can be bought/recharged in a single period (MWh)
$\bar{S}$	maximum storage capacity (MWh)

Armed with a model for the system state of charge, it is straightforward to quantify the financial costs/benefits associated with charging and discharging while engaging in a functional use. The revenue at each time step is given by

$$R_t = q_t^d(P_t^d - C_t^d) - q_t^c(P_t^c + C_t^c) \tag{1.24}$$

where

P_t^d	Price received for discharging at time period t (\$/MWh)
C_t^d	Cost for discharging at time period t (\$/MWh)
P_t^c	Price paid for charging at time period t (\$/MWh)
C_t^c	Cost for charging at time period t (\$/MWh)

The present value of the energy storage system can be written as

$$\text{Present Value} = \sum_{t=1}^{N} \left(q_t^d(P_t^d - C_t^d) - q_t^c(P_t^c + C_t^c) \right) e^{-rt} \tag{1.25}$$

Using this relationship, it is possible to calculate the present value of a system using either historical or estimated price data under a wide range of scenarios. The charge/discharge quantities can be derived to maximize revenue (e.g. a linear programming optimization problem) or are generated by a candidate control algorithm. In a market area one can utilize historical price data. In a vertically integrated utility the most difficult task is estimating the appropriate prices and costs to use in the model [3]. An example of estimating the maximum potential revenue from participating in arbitrage and frequency regulation is described in [15].

The next chapter discusses the technical performance requirements for various grid services that may be provided by an electrical energy storage system.

[3] This is discussed further in Chapter 3

Chapter 2

Technical Performance Requirements

2.1 Introduction

Grid-connected energy storage systems have the potential to provide a variety of benefits. This section specifies the technical requirements a given storage system must meet in order to claim the system provides a given benefit. These requirements are broken down into four categories:

1. Specify requirements a storage system must meet to claim it provides a benefit.
2. Identify the engineering tests and analyses required to quantify the extent to which a given storage system provides a benefit.
3. Identify the technical data required to assess the benefits.
4. Make recommendations on what monitoring technologies are well suited to provide the required data.

The framework for classification of the benefits of grid-connected storage was generally taken from [16, 17]. However, the goals of this report have a sharper technical focus. When viewing the benefits described in [16] with this focus, it became natural to re-group the benefits into a smaller set of categories. All benefits within a given category require similar technical assessment to measure achievement of the benefit. We form three broad categories along with sub-categories for the purpose of assessing the technical requirements of grid-connected storage devices:

- Energy supply interactions
    - Short-term energy shift
    - Long-term energy shift
- Grid Operations
    - Regulation and frequency control
    - Voltage
    - Power-factor control
    - Angle stability control
    - Sub-synchronous resonance
    - Shedding (under frequency or under voltage)

- Quality and reliability
    - ◦ UPS applications
    - ◦ Harmonics

The engineering issues and time frames associated with each of these classes play a large part in dictating the technical requirements and monitoring needs. For example, sub-synchronous resonance has a time-frame of milliseconds while long-term energy shift has a time frame of hours.

A grid-connected electric energy storage system includes the physical storage device, specific controls to operate the device, and external controls and equipment to connect and interact with the grid and address the desired applications. The impact of a storage system on a particular grid issue will involve a combination of the system's inherent ability to respond to the issue, the external control system design and settings, and the location of the interconnection to the grid. Ideally, testing, assessment, and monitoring would be conducted to separate the response of the external controls from the inherent storage device response. In reality, this may not be possible depending on the overall system design. The testing, assessment, and monitoring requirements specified in this document attempt to separate the responses of the fundamental storage device and the external control system.

In an ideal setting, testing would be conducted to quantify the impact of the interconnect location. For example, a given storage system may have the inherent ability to supply a given benefit, but its particular interconnect location prohibits providing the benefit. An example of this might be locating an energy storage device with the capability to mitigate harmonics in a "stiff" area of the bulk power grid that does not suffer from poor power quality. A device so located may still provide myriad other benefits, but it cannot deliver the benefit of harmonic mitigation due to its location on the grid. The testing, assessment, and monitoring requirements specified in this document also attempt to separate the response of the fundamental storage system from any fundamental limitations inherent from the interconnect location.

Energy storage technologies considered in this document include batteries, flywheels, pumped hydro, compressed air, and any other technology that can store energy and that can be used to provide system benefits when connected to the bulk power grid. Each of these technologies has unique operation and control requirements. When interconnected to the grid, each will require interface through a three-phase synchronous connection. In order to provide grid benefits, a storage device must be equipped with customized control systems and interfacing equipment. The real-power injected into the grid must be a controllable variable. If the device is equipped with reactive-power control equipment, a second related settable variable must be provided. Set point options for reactive power control may include one or more of the following:

- Voltage control - the terminal positive-sequence voltage magnitude;
- Power-factor control - the terminal power factor; or
- Reactive power control - the magnitude of the output reactive power.

Variables used in this report include the following.

- Possible inputs to the storage device are:
    - ◦ $P_{set}(t)$ = the set-point rms positive-sequence real power desired out of the device at time t. A negative $P_{set}(t)$ refers to a device's charging state.
    - ◦ $P_{ref}(t)$ = the reference rms positive-sequence real power at time t. In many cases $P_{set}(t)$ is not equal to $P_{ref}(t)$ due to the frequency control system.

○ $V_{ref}(t)$ = the reference *rms* positive-sequence voltage desired out of the device at time t assuming the device is equipped with reactive-power controls and operates in voltage control mode.

○ $PF_{ref}(t)$ = the reference power factor desired at the device terminals at time t assuming the device is equipped with reactive-power controls and operates in power-factor control mode.

○ $Q_{ref}(t)$ = the reference *rms* positive-sequence reactive power desired out of the device at time t assuming the device is equipped with reactive-power controls and operates in reactive-power control mode.

○ NOTE: only one of V_{ref}, PF_{ref}, and Q_{ref} is possible for a given application.

- Outputs of the device are:

○ $P(t)$ = the true *rms* positive-sequence electrical real power out of the storage unit at time t, measured at the terminals of the storage device or at the utility point of interconnection.

○ $Q(t)$ = the true *rms* positive-sequence electrical reactive power out of the storage unit at time t, measured at the terminals of the storage device, at the utility point of interconnection, or at some location remote from the storage device as required to achieve the desired effect.

2.2 Technical Categories and Benefits

As discussed above, a specific energy storage technology connected to the bulk electric power grid through a specific interface technology, for example a power electronic converter or a synchronous generator, placed at a specific location may not be capable of delivering a comprehensive range of benefits due to technical limitations. Similarly, this hypothetical storage device/grid interface combination placed at a specific location may not be capable of simultaneously delivering multiple benefits to the grid due to technical and physical constraints. Therefore, for the purpose of monetizing the benefits provided by grid-connected storage systems it is appropriate to meticulously discriminate between specific benefits so that they can be independently evaluated for the value derived. However, this is not so for the purpose of evaluating the technical capability of a particular storage technology to meet the desired benefit.

Table 2.1 describes a framework for further addressing the requirements for technical evaluation of the capability of an energy storage device to meet a given benefit. Benefits identified in [16] are categorized primarily according to the time frame required to implement a complete charge/discharge cycle while delivering the stated benefit.

It follows from the assignment of the three discussion categories shown in the table that certain monitoring, data collection, analysis and evaluation methods and tools are applicable to certain categories. The categories outlined in the table carry forward throughout the document.

2.3 Generic Data Collection Requirements

Table 2.2 is intended to describe broad categories of data acquisition and monitoring equipment suitable for use in collecting data for analysis within three monitoring classifications. Acronyms and abbreviations are further defined in the acronyms, abbreviations, and definitions section at the beginning of the report. In Table 2.2 we attempt to describe classes of monitoring/information systems. These data/information source classes are then used as a guide for each benefit class

Table 2.1: Categories of benefits for technical evaluation.

Category name and description	**Mapping of benefit described in [16]**	**Designator in [16]**
Energy supply interactions	Short-term energy shift (minute time frame)	
Definition - Use of the energy storage device to support the "adequacy" of the supply-side to meet the needs of the demand-side. "Adequacy" is a term in common use in the industry and is defined in the glossary.	• Renewable capacity firming	16
	• Wind generation grid integration	17
	Long-term energy shift (hour time frame)	
	• Electric energy time-shift	1
	• Electric supply capacity	2
	• Electric supply reserve capacity	5
	• Transmission congestion relief	8
	• T&D upgrade deferral	9
Time frame - Long. A single charge/discharge cycle may take hours to complete.	• Time-of-use energy cost management	11
	• Demand charge management	12
	• Renewable energy time shift	15
Sub-categories - Short-term (minutes); Long-term (hours).	• Increased asset utilization	18
	• Avoided transmission and distribution energy losses	19
	• Avoided transmission access charges	20
	• Reduced transmission and distribution investment risk	21
	• Dynamic operating benefits	22
	• Reduced generation fossil fuel use	24
	• Reduced air emissions from generation	25
Grid operations	Regulation and frequency control	
Definition - Use of the energy storage device to support the real-time control of the electric power grid.	• Load following	3
	• Area regulation	4
	Voltage control	
	• Voltage support	6
Time frame - moderate to short. A charge/discharge cycle may take seconds or, at the most, minutes to complete.	• Transmission voltage support - voltage stability	7
	Power factor control	
	• Power factor correction	23
	Angle stability control	
Sub-categories - Regulation and frequency control; voltage control; power factor control; angle stability control; sub-synchronous resonance; shedding.	• Transmission support - transient and small-signal stability	7
	Sub-synchronous resonance	
	• Transmission support - sub-synchronous resonance	7
	Shedding (under frequency or voltage)	
	• Transmission support - shedding	7

Table 2.1: Categories of benefits for technical evaluation (continued).

Category name and description	Mapping of benefit described in [16]	Designator in [16]
Quality and reliability **Definition** - Use of the energy storage device to support the quality and/or reliability of energy delivered to the end-use. **Time frame** - Short. A single charge/discharge cycle may be on the order of milliseconds. **Sub-categories** - UPS applications; harmonics.	UPS applications • Electric service reliability Harmonics • Electric service power quality	 13 14

to define data needs for future analysis. Some key points with respect to all data/information collection systems are shown below.

- All monitoring should be time-tagged. The accuracy of the time tag may vary with each monitoring class, but all measurements need to be capable of being correlated with one another. Some common difficulties with respect to time-tagging are time zone errors, daylight savings time conversions, inaccurate and uncalibrated[1] clocks, and other sources of error. *It is recommended that all data acquisition systems use the GMT (Greenwich Mean Time) time zone for all tagging.*

- All monitored signals should have a bandwidth commensurate with the sample rate. This includes all components of the data acquisition system, from sensor to transducer to sampler. For example, a band-limited transducer must not be used in a high sample rate application. As a rule of thumb, the chain of components comprising the entire measurement system should have a bandwidth of approximately 1/4 of the sample rate (for example, the components of a system sampling at 30 *sps* should have a bandwidth of 7.5 Hz). This is typical of most data acquisition systems.

- The sampler should have an adequate dynamic range to cover all expected operating conditions. In the simplest example, a power transducer used to measure both charging and discharging of a storage system should have the same range in both the positive and negative direction.

Table 2.3 shows examples of data acquisition systems in each of the classes listed in Table 2.2. The examples are not meant to be prescriptive, nor are they representative of the entire range of acceptable monitoring equipment. The examples are for illustrative purposes only. They do not form an endorsement or recommendation for a particular device or manufacturer. Even a cursory review of the literature will reveal that there are many available options and that there is much overlap between the technology categories described in this report.

[1]The calibration source should be commensurate with the required accuracy of the time tag.

Table 2.2: Classification of monitoring equipment.

	Abbrev.	Type	Sampling style	Possible Variables	Typical sampling rate	Time accuracy
Physical quantities	LGR	Data logger	Continuous equi-spaced samples	V, I, P, Q, P_{ref}, V_{ref}, PF_{ref}, SoC (positive sequence) breaker status, analogs/digitals	1/60 sps	±1 sec
	DAQ	DAQ	Continuous equi-spaced samples	V, I, P, Q, f, P_{ref}, V_{ref}, PF_{ref}, ue, Soc (positive sequence), V_{abc}, I_{abc} breaker status, analogs/digitals	1 sps	±1 $msec$
	PQM	PQM monitor	Burst sampling (oscillographic) recording	V_{abc}, I_{abc} (point-on-wave, 3 phases)	5000 sps	±1 sec
	PMU	PMU	Continuous equi-spaced samples	V, I, P, Q, P_{ref}, P_{set}, U, V_{ref}, PF_{ref}, ue, SoC (positive sequence), V_{abc}, I_{abc}, breaker status, analogs/ digitals	30 sps	±1 $usec$
System and market quantities	MKT	OASIS data	Publicly available information from OASIS	ATC, daily peak, pricing relevant constraints	1/900 sps	±1 min
	SYS	Reliability data	Publicly available information from ISO's, reliability councils, or other sources	Hourly demand, relevant constraints, emergency conditions, etc.	1/900 sps	±1 min
Other quantities	ENV	Data logger	Publicly available from NOAA or elsewhere. May also be surrogate for these quantities such as real power output from wind farm or PV array	Temperature, wind speed, solar illumination, or P from wind farm or solar array	1/900 sps	±1 min

Table 2.3: Examples of monitoring equipment.

Type	Examples
Logger	Shark 200S (www.electroind.com)
DAQ	NI CompactDAQ (www.ni.com) Phoenix Contact EMpro MA600 (www.phoenixcontact.com)
PMU	SEL 351 (www.selinc.com) ABB RES521 (www.abb.com)
PQ Monitor	AEMC PowerPad (www.aemc.com) Fluke 1740 (www.fluke.com) GE F60 with DDFR (www.gedigitalenergy.com/multilin)
OASIS	Western OASIS nodes (www.tsin.com/nodes/wscc.html) Market data from a participating host utility may also be a good source
Reliability	ERCOT historical (http://www.ercot.com/gridinfo) SCADA data from a participating host utility may also be a good source

2.4 Energy Supply Interactions

Energy supply interactions are broadly defined as slow exchanges of energy between the bulk electric supply sources and the energy storage device. Energy supply interactions often occur when there is a disparity between the current market price of electricity and the future expected market price. These interactions usually occur over periods of many minutes or hours.

It could be argued that every exchange of energy between the bulk power grid and the storage device meets this definition, however, as previously discussed, the primary differentiator between this definition, and that of the Grid Operations category and the Quality and Reliability category is the speed with which the storage device is required to operate.

The energy supply interactions category encompasses the majority of the specific benefits attributable to a stationary storage device. Two sub-categories can be identified, as described in Table 2.1, to provide more definition to the technical requirements placed upon a storage device providing benefits in this category.

2.4.1 Short-term energy shift (minute time frame)

Short-term energy shift primarily encompasses the benefits associated with the use of storage to balance renewable energy generation sources. It could also be argued that some of the value attributable to "Dynamic Operating Benefits", as described in [16], may also be captured in this sub-category.

Short-term energy shift is characterized by a storage device's application as a "firming" source to allow a piece of generating equipment to be scheduled as a firm resource. New schedules for the generation fleet have historically been posted hourly, but with the increasing levels of renewable energy, transmission operators are now implementing sub-hourly dispatch of generation. Therefore, for a storage device to offer an effective service in this category the device must be capable of routinely providing real power injections in a time frame of minutes and must sustain these real power injections for periods of up to one hour.

There is now considerable data available regarding the variability of wind and solar power

Table 2.4: Wind power plant variability [4, 5].

Plant Capacity (MW)	Maximum 1-minute change (MW)	97.5% of 1-minute changes are under (MW)	Maximum 10-minute change (MW)	97.5% of 10-minute changes are under (MW)
358.5	N/A	8	112	30
741	136	11	210	47
895	116	9	202	40
1445	149	12	208	56
1450	158	20	314	74
1994	222	14	259	70

plants. Two studies performed in the northern Rocky Mountains serve to illustrate the issue for wind power plants [4, 5]. Summary data from these studies is shown in Table 2.4. It must be noted that variability is not the key factor in determining the value from a short-term energy shift. Rather, the key factor is the amount of deviation from the generation forecast for the wind/solar power plant. Nevertheless, if a storage device is to perform the function of smoothing variability from an intermittent generating source to "firm" the source then the storage device must have the technical capability to track the generating source's variability.

In order to attempt to quantify the technical requirements for a device claiming a short-term energy shift benefit, one might express the results of Table 2.4 as a percent of the nameplate capacity of the renewable energy source. A rule-of-thumb requirement using this approach might state that the storage device must be capable of ramping at a rate of 12%[2] of the nameplate capacity per minute for the generation resource deriving the benefit. Similar rules-of-thumb could be derived for ramp rate requirements to meet solar photovoltaic power plants.

Unlike the requirements for Grid Operations and Quality/Reliability described below, some short-term energy shift benefit can be realized from any reasonable ramp rate provided by the storage device. For example, if a wind power plant sees a sudden decrease of 100 MW in one minute due to some peculiar weather event and a storage device responds at a rate of 10 MW per minute a certain amount of benefit is still realized. This makes it difficult to quantify absolute requirements for storage devices claiming a short-term energy shift benefit. However, it should suffice to assert that some storage technologies may be too slow to capture the full value of the benefit, but any storage device having a reasonable capacity should be able to provide some degree of benefit in this sub-category.

The task of validating that a storage device is providing short-term energy shift benefits may be easier than the task of quantifying performance requirements for the same sub-category. Figure 2.1 shows a block diagram of a generalized set point controller using remote measurements. For example, the remote measurements may be transmitted to the storage device from a wind power plant. The variables include:

- t = time.
- $P_{ref}(t)$ = the reference rms positive-sequence real power at time t (this value may, for example, be the scheduled value for the wind power plant as communicated from the area control

[2] 12% is approximately the average of the maximum 1-minute deviations from the table.

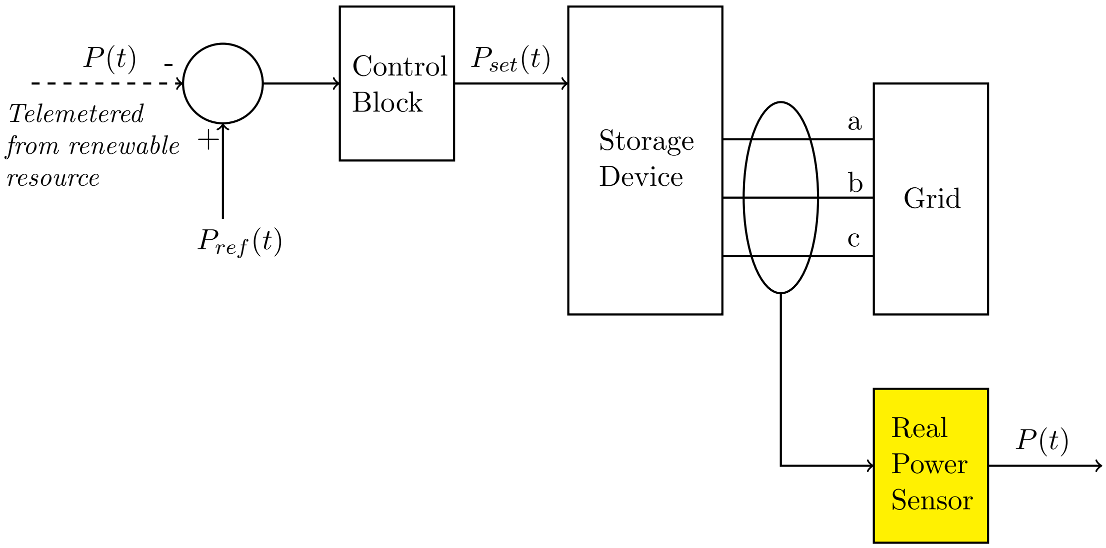


Figure 2.1: Generalized set point controller using remote measurements.

center).

- $P_{set}(t)$ = the set-point *rms* positive-sequence real power desired out of the device at time t.
- $P(t)$ = the true *rms* positive-sequence electrical real power out of the storage unit or out of the renewable resource power plant at time t.
- *abc* =three-phase electrical connection to grid.

The ramp rate of the storage device may be determined by inputting a step-change at $P_{set}(t)$ and subsequently measuring the output of the storage device at $P(t)$. As discussed previously, most storage technologies will not be rate-limited with respect to this benefit sub-category.

To determine the value delivered, the analyst must have access to the generation forecast for the renewable resource benefited, the real power output from the renewable resource benefited, the real power output from the storage device, and the locational price of energy. Each of these analysis variables must be recorded and stored as a time history. Because of the long time constants involved in this application it will be necessary to collect months, if not years, of data to obtain statistically meaningful analysis results. Data should be collected at a sampling rate of one sample per minute (1/60 sample per second) for variables over which the analyst has control (for example, $P(t)$). For variables over which the analyst does not have control, such as price of energy, data should be stored at the fastest rate offered by the controlling agency.

A simple data logger should be sufficient to record the electrical variables, though a SCADA system is preferred. Price and forecast information can be collected from the appropriate source via a network connection and recorded with a time stamp in the data repository.

2.4.2 Long-term energy shift (hour time frame)

Long-term energy shift involves storing energy when there is excess supply capacity and injecting energy when there is high demand. In most cases the signal indicating the conditions of supply and demand will be a price signal, but other indicators are also possible. Arbitrage as defined in [16], is one form of long-term energy shift.

It should be noted that excesses or shortages in electric energy supply may, in some cases, be localized. This can occur when a geographic area is constrained by the capacity of the transmission

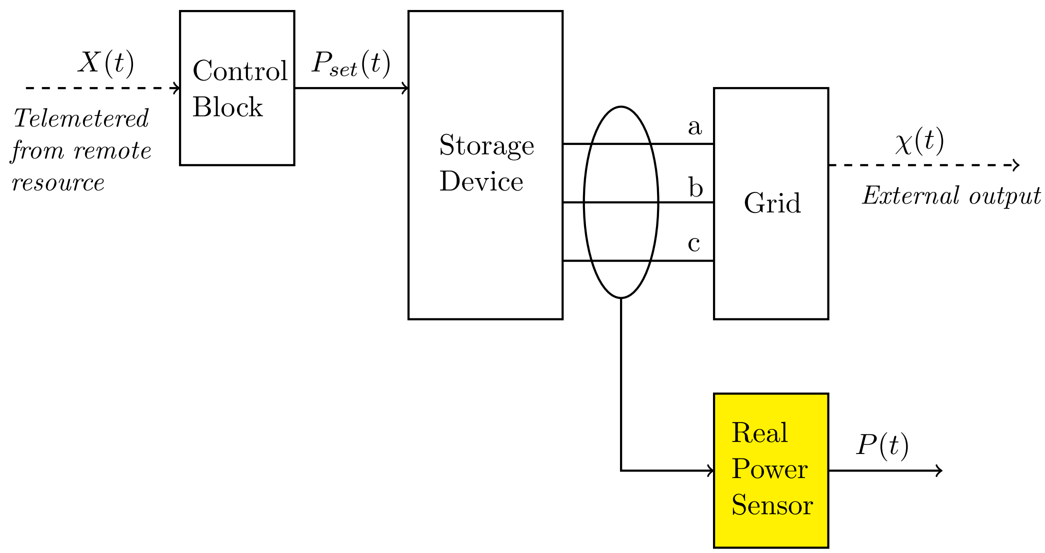


Figure 2.2: Generalized controller for long-term energy shift.

system connecting a "load pocket" to the rest of the bulk power grid. In all cases, long-term energy shift involves very slow charge/discharge cycling of the storage system.

The technical requirements, technical performance validation and monitoring requirements for long-term energy shift are identical to that of short-term energy shift with one exception. The sample rate of the monitored variables can be slower for long-term energy shift than for short-term, and the analyst may find it to be prudent to use averaging or some form of moving average (MA) filter on the measured variables before storing them to the data archive. From a signal processing perspective, an anti-aliasing filter would achieve the same goal. A common form of averaging for this kind of data collection is to record the average $P(t)$ in 15-minute blocks with no overlap. It is important to note that although the data is recorded at a relatively slow rate, the quantity of interest must be sampled at a higher rate and then filtered. Otherwise, information is lost (for example, the case where $P(t)$ is sampled once every 15 minutes).

Figure 2.2 shows a block diagram of a generalized controller for long-term energy shift. The variables include:

- t = time.
- $P_{set}(t)$ = the set-point rms positive-sequence real power desired out of the device at time t.
- $P(t)$ = the true rms positive-sequence electrical real power out of the storage unit or out of the renewable resource power plant at time t.
- $X(t)$ = an external input, often the price of energy at time t, used to affect control of the storage device.
- $\chi(t)$ = an external output from the grid at time t that is to be used to assess the value of the benefit derived. An example might be the CO_2 emissions from a power plant that was formerly operating in "load following" mode but that is now, due to the storage device, operating as a "base load" unit.
- abc = three-phase electrical connection to grid.

$P(t)$ should be sampled at least as frequently as the update rate on the price signal, or other signal, used in the decision logic for the benefit being analyzed.

2.5 Grid Operations

Grid operations may include both transmission and distribution operations practices. The most complex analyses involve real power dispatch and automatic control operations for transmission operations. Distribution operations are more closely connected to maintaining an acceptable voltage profile and dispatching reactive power.

While energy supply interactions involve relatively long time frames, some of the grid operations focus areas are quite fast, with commensurately fast monitoring requirements. For this reason, the following sections provide more depth than the previous ones.

In many cases, there are no clearly defined requirements that a generic device (including generators) must meet to claim it supports a given grid issue. The requirements specified in this document take a conservative view. That is, if a storage device meets the requirements specified below for a given issue, then assuredly the device can claim it serves that issue. But, if the device does not meet the requirements, it may still help in the given issue depending on the extent to which the requirements are not met.

2.5.1 Regulation and frequency control

As referenced in [16], the term "Regulation" refers to the control of a storage device as part of an Area Generation Control (AGC) system. Traditionally, each control area within a grid periodically sends a reference power (P_{ref}) to key swing generators. A component of P_{ref} is calculated with the goal of driving the Area Control Error (ACE) to zero. The ACE is a combination of tie-line power flow errors and frequency error for the control area of interest.

AGC is only one of two power-system components focused on frequency control and load balancing (excluding under-frequency load shedding). Power-system frequency control is usually broken into primary and secondary control [2]. Primary control relates to how the system immediately reacts to a sudden disturbance (such as a generator trip) over the first several seconds and is mainly a function of the automatic speed-governor control systems on key generators within the system. Often, speed governor controllers are operated with a dead-band, so they are only activated under severe system conditions. Secondary control relates to several minutes after primary control and is primarily a function of the AGC system's reaction to the disturbance. In reality, the dynamic division between primary and secondary frequency response is somewhat fuzzy. It depends on many factors including the bandwidth of the control systems and controlled devices (for example, generation and storage).

The Regulation definition in [16] is expanded to include both frequency control components. Regulation is typically incorporated into a generation device (and expectedly a storage device) through combination with a "speed governing" control system – a frequency-based feedback control system. Therefore, monitoring a storage device's participation in Regulation cannot be separated from the traditional speed-governing control. Figure 2.3 shows a block diagram of a generalized speed-governing/Regulation control system. The variables include:

- t = time.
- f_{ref} = desired electrical frequency at the grid connection (60 Hz).
- $f(t)$ = actual fundamental frequency measured at the grid connection at time t.
- $f_e(t)$ = frequency error at time t.
- $u(t)$ = output of Speed Governor Control Block at time t.
- $P_{ref}(t)$ = the reference *rms* positive-sequence real power at time t (for units participating in Regulation, this value is communicated from the area control center (for example, an ISO)).

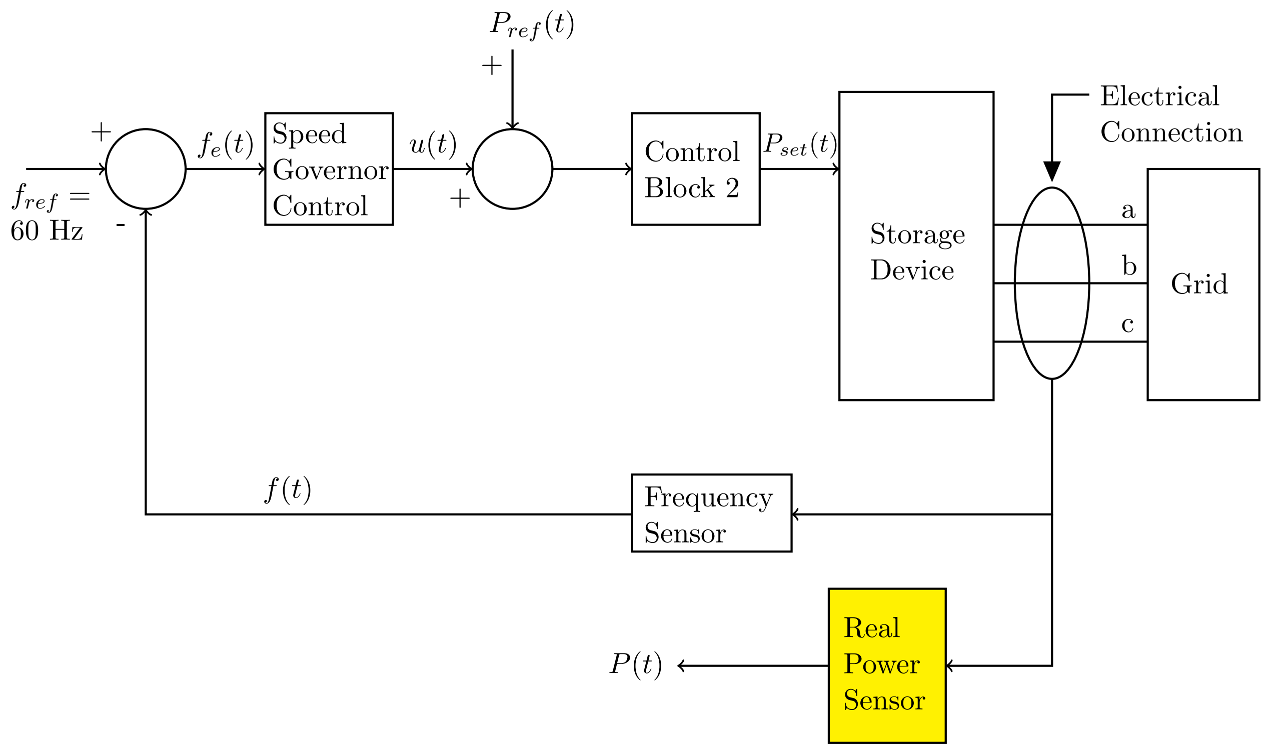


Figure 2.3: Generalized speed-governor/Regulation control system used to set $P_{set}(t)$.

- $P_{set}(t)$ =the set-point rms positive-sequence real power desired out of the device at time t.
- $P(t)$ = the true rms positive-sequence electrical real power out of the storage unit at time t.
- abc = three-phase electrical connection to grid.

Performance and design of control systems is beyond the scope of this document. But, the high-level fundamental goal is to have P track P_{set}. Normally in steady-state $P_{set} = P_{ref} + u$. The signal $u(t)$ contains the frequency bias of Speed-Governor Control Block. There are several variations of the control system; but, all follow the general format shown in Figure 2.3 . The sensor for P is shown high-lighted in yellow as it is not necessary for operation of the control system; but, it is necessary for monitoring the storages device's frequency control ability.

It is possible that a device will not be equipped with the Speed-Governor Control block and the corresponding frequency feedback. In this case, the Speed-Governor Control Block is not included and P_{ref} directly feeds into Control Block 2.

One goal in testing and assessing a storage device's participation in frequency control is to separate the response of the control system from the device. Using Figure 2.3 as an example, the goal is the study of the response from P_{set} to P. This will necessarily require disabling some components of the external control system during testing. For example, the external control system is disconnected at P_{set} and test signals are driven into the storage device. Other tests will require testing the device in conjunction with the control system.

Testing and assessing a storage device requires monitoring for both primary and secondary frequency response. In general, this requires assessing how well P tracks P_{set} both in open loop and closed loop configurations. Testing involves inputting test signals in the form of step functions and ramps into P_{set} and/or P_{ref} and measuring the corresponding response at P. These tests must be conducted with the device grid connected and operating under all possible allowed charge states.

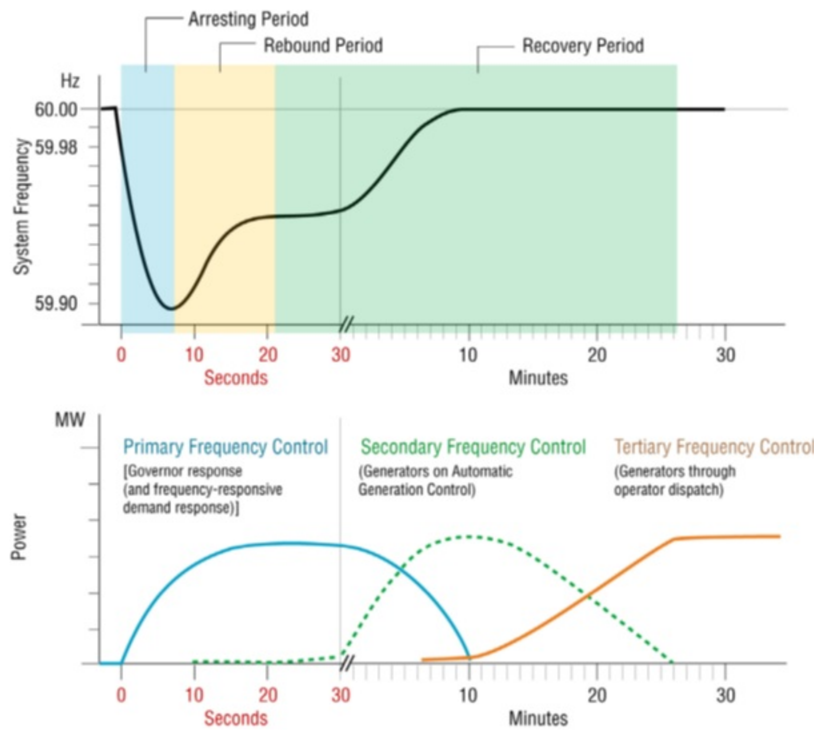


Figure 2.4: The sequential actions of primary, secondary, and tertiary frequency controls following the sudden loss of generation and their impacts on system frequency. Taken from reference [2].

In typical AGC systems, P_{ref} is updated every few seconds (for example, every 4 seconds). The response time of the storage device to these changes provides assessment of the device's ability to participate in Regulation. No standard requirements exist for the response time; but, a response time on the order of one minute is fairly standard.

Figure 2.4, which is taken from [2], is demonstrative of a typical system response to a large generator trip. Immediately after the generator trip, frequency starts to fall. Generators equipped with speed-governor controls immediately start to raise their power output. If the system is stable, frequency reaches a minimum (termed the nadir point) and then starts to recover. Due to the droop designed into the speed-governor controls, the frequency initially recovers to a level below the rated (60 Hz) and the recovery occurs within about 30 seconds. The secondary controls (AGC) then further adjust generator outputs to bring the frequency back to 60 Hz over the subsequent several minutes.

After a major frequency event, many of the power outputs of controlled generators are out of bounds. In many cases, the generator reserves (the portion held back for speed governor and AGC actions) are consumed. The"Tertiary" control refers to the centrally coordinated actions to restore generator reserves back to a level to accommodate another major event. They provide a general guideline of how long a storage device must sustain response as a secondary control device.

Frequency Control Tests, Monitoring, and Requirements

Table 2.5 and Table 2.6 summarize the tests, monitoring, and requirements for primary frequency control and secondary frequency control, respectively. Each condition (primary and secondary) specify three tests. For both conditions, the goal of Test 1 is to evaluate the storage device separately from the control system. In addition, Tests 2 and 3 evaluate the entire "storage system;" that is, the storage device operating with the control system active and the system synchronized to the grid. It is recommended that all three tests be conducted under a variety of charge and discharge states to demonstrate the limits of operation. That is, show when and how the storage system switches out of frequency control.

2.5.2 Voltage Control

The primary purpose of a voltage control application is to help maintain grid reliability. Voltage support and control can be broken into two categories: transient response and steady-state response. Transient response relates to how fast the device can provide reactive power to the grid following a fault in order to maintain transient stability. Transients can be very fast with first-swing dynamics measured in the sub-second range. Steady-state response relates to the constant voltage condition under ambient conditions. Both are critical to the reliability of a grid.

Traditionally, voltage support is broken into transmission level control and distribution level control. The transient requirements are supplied by the transmission system via generator controls, and fast-acting reactive devices including Flexible AC transmission system (FACTS) devices. Steady-state voltage support is provided at both the transmission level and the distribution level. The primary distribution level device is the tap-changing transformer.

Assuming a storage device is equipped with voltage control capability, the response and ability of the device to control voltage is highly dependent on the external control system and equipment. Many equipment and interface strategies are possible and many may not be disclosed to the end user. Therefore, we propose testing and assessing voltage support benefits using a black-box approach. The testing and assessment must also consider if the support is transient and/or steady state.

A storage device operating under voltage control will effectively vary the output reactive power to obtain the desired terminal voltage. A high-level perspective of the control system is shown in Figure 2.5. Variables include:

- t = time.
- $P_{set}(t)$ = the set-point rms positive-sequence real power desired out of the device at time t.
- $V_{ref}(t)$ = the reference rms positive-sequence voltage desired out of the device at time t.
- $u_e(t)$ = the control signal transferred to the storage device from the Voltage Control block. Often termed the excitation signal. The unit and form of this signal depends on the reactive power handling equipment employed by the storage unit.
- abc = three-phase electrical connection to grid.
- $V_a(t),\ V_b(t),\ V_c(t)$ = rms three-phase voltage magnitudes at the terminals of the storage unit (may be line-to-line or line-to-neutral) at time t.
- $V(t)$ = rms positive-sequence voltage at the terminals of the storage unit at time t.
- $P(t)$ = the true rms positive-sequence electrical real power out of the storage unit at time t.
- $Q(t)$ = the true rms positive-sequence electrical reactive power out of the storage unit at time t.

A typical Power Control block is shown and defined in Figure 2.5. Performance and design of the Voltage Control block is beyond the scope of this document. The high-level fundamental goal is to have V track V_{ref}. The sensors for P and Q are shown high-lighted in yellow as it is not necessary for operation of the control systems, but, is necessary for monitoring the storage device's voltage control ability.

Table 2.5: Primary frequency control tests, monitoring, and requirements.

Test Num	Test Name	Test Description	Monit'rd Var's	Monitoring	Requirements
1	Storage Device, Direct Response (Open Loop)	Open control loop at P_{set}. Leave all other control systems in place and device connected to grid. Apply three consecutive step inputs separated by 2 minutes each to P_{set}. The second step shall be in the opposite direction of the first. For example, if the first step is 20% full scale (FS) then the second step is -20% FS, and the third 20% FS.	P_{set}, P, I_{abc} phasors	PMU (5 sps minumum). Monitoring must include at least 5 min. of data prior to the first step input and 5 min. after the third step input.	$P(t)$ must follow $P_{set}(t)$ over the entire 16 min. For the 3 step responses, the system must meet the following specs (see Appendix A under Step Response): $T_s \leq 10$ sec. and % OS $< 10\%$ Must meet above specs under both charge and discharge conditions. $P(t)$ must have a resolution of 10% or less of rated output. A variety of step input amplitudes shall be tested and must include a step input of 10% and 100% of full scale in both charge and discharge. I_{abc} must remain balanced during transients.
2	System, Active Response (Closed Loop)	With the control system active and the device connected to the grid, set P_{ref} to zero. Apply three consecutive step inputs at f_{ref}, each separated by 2 minutes. The second step shall be in the opposite direction of the first and the third.	P, P_{ref}, f_{ref}, f, I_{abc} phasors	PMU (5 sps minumum). Monitoring must include at least 5 min. of data prior to the first step input and 5 min. after the third step input.	$P(t)$ must follow $f_e(t)$ over the entire 16 min. with appropriate droop scaling. For the 3 step responses, the system must meet the following specs (see Appendix A under Step Response): $T_s \leq 10$ sec. and % OS $\leq 10\%$ If $P(t)$ saturates, it must remain saturated until the control demands a lower value. Must meet settling time under both charge and discharge conditions. $P(t)$ must have a resolution of 10% or less of rated output. A variety of step input amplitudes shall be tested and must include a step input of 0.01 Hz and 0.1 Hz. I_{abc} must remain balanced during transients.
3	System, Passive Response (Closed Loop)	Actively monitor system during grid interconnect. Capture significant frequency events within the system as well as the device's response.	P, P_{ref}, f, I_{abc} phasors	PMU (5 sps minumum). Monitoring must include at least 5 min. of data prior to the event and 5 min. after the event.	$P(t)$ must follow $f_e(t)$ with appropriate scaling over the entire 10 min. with a maximum of 2 sec. delay measured at the frequency nadir. Events in both charge and discharge state must be captured. $P(t)$ must have a resolution of 10% or less of rated output. I_{abc} must remain balanced during transients.

Table 2.6: Secondary frequency control tests, monitoring, and requirements.

Test Num	**Test Name**	**Test Desc.**	**Monitrd Var's**	**Monitoring**	**Requirements**
1	Storage Device, Direct Response (Open Loop)	Open control loop at P_{set}. Leave all other control systems in place and device connected to grid. Apply step inputs to P_{set}.	P_{set}, P	DAQ (1 sps minumum). Monitoring must include at least 5 min. of data prior to the input and 30 min. after input.	$P(t)$ must follow $P_{set}(t)$ over the entire 35 min. and respond with a settling time of 1 min. or less to the step. Must meet settling time under both charge and discharge conditions. $P(t)$ must have a resolution of 10% or less of rated output. A variety of step inputs shall be tested and must include a step input of 10% and 50% of full scale in both charge and discharge.
2	System, Active Response (Closed Loop)	With the control system active and the device connected to the grid, apply step inputs at P_{ref}.	P, P_{ref}, f	DAQ (1 sps minumum). Monitoring must include at least 5 min. of data prior to and 30 min. after input.	$P(t)$ must follow $P_{ref}(t) - Droop * f_e(t)$ over the entire 35 min. with appropriate scaling and have a settling time of 1 min. or less. Must meet settling time under both charge and discharge conditions. $P(t)$ must have a resolution of 10% or less of rated output.
3	System, Passive Response (Closed Loop)	Actively monitor system during grid interconnect. Capture significant frequency events within the system as well as the device's response.	P, P_{ref}, f	DAQ (1 sps minumum). Monitoring must include at least 5 min. of data prior to the event and 30 min. after the event.	$P(t)$ must follow $P_{ref}(t) - Droop * f_e(t)$ with appropriate scaling over the entire 35 min. with a maximum of 10 sec. delay. Events in both charge and discharge state must be captured. $P(t)$ must have a resolution of 10% or less of rated output.

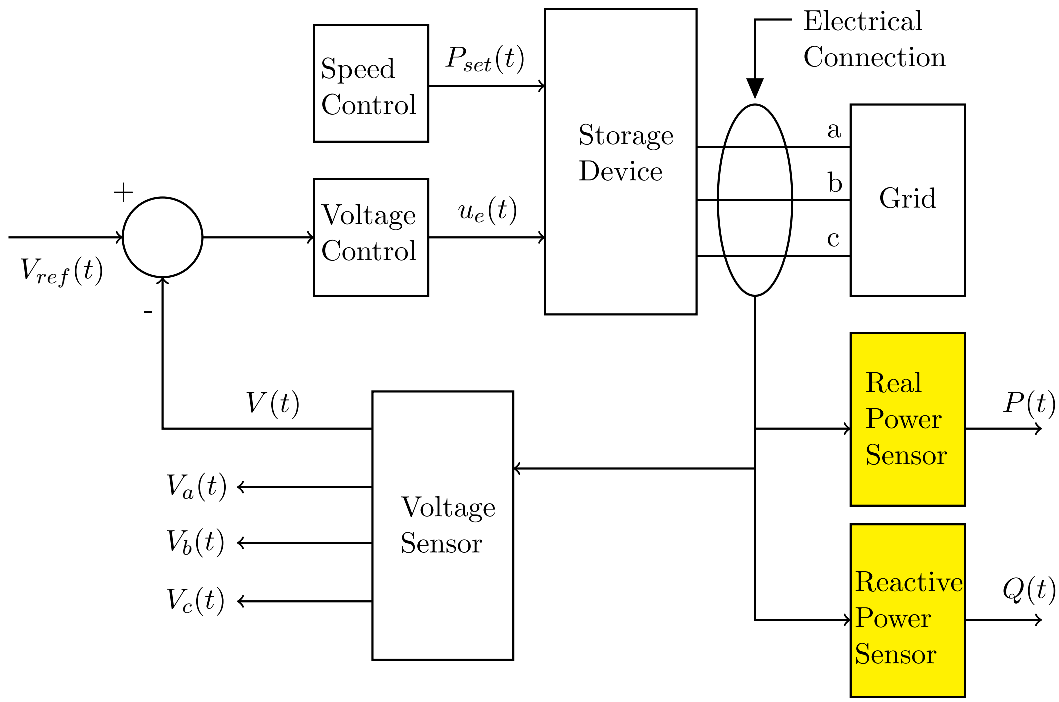


Figure 2.5: Generalized voltage control system.

Voltage Control Tests, Monitoring, and Requirements

As illustrated in Figure 2.5, testing and assessment of a storage device's voltage support and control requires time-synchronized monitoring of V_{ref}, V_{abc}, V, P_{set}, P, and Q with the system connected to the grid. Two distinct sets of experiments are required: one to assess the transient performance, and one to assess the steady-state performance.

Details for the transient test are given in Table 2.7. The test involves applying step inputs at V_{ref} and measuring the system's response with the control in operation and the system synchronized to the grid. Several step inputs need to be applied under a variety of step sizes and charge/discharge states. If the control is unable to drive the voltage to the desired level due to limitations from the grid, then the output $Q(t)$ should go to a saturation level and remain there until switching back to voltage control. At least one step input should demonstrate this condition. The sample-rate and bandwidth of the monitoring needs to be set to capture the full response time of the device. Rates on the order of 30 *sps* are common.

Steady-state voltage control tests are given in Table 2.8. For the first test, the system is operated with the control systems active and synchronized to the grid. Step inputs are applied at V_{ref} and the response of the system is monitored. The second test consists of capturing events within the grid and recording the storage system's response.

2.5.3 Power Factor Control

Unlike voltage control, the primary benefit for power factor (PF) control is to correct the PF for the customer. Often the goal is to reduce energy costs for the customer. Under such conditions, there is no desire for transient response capability as with voltage control. Monitoring would therefore be very similar to monitoring steady-state voltage control. An additional benefit is an increase in available transmission capacity. Higher real power levels can be achieved while still meeting the

Table 2.7: Transient voltage control tests, monitoring, and requirements.

Test Num	Test Name	Test Desc.	Monit'rd Var's	Monitoring	Requirements
1	System, Active Response (Closed Loop)	With the control system operating and the device connected to the grid, apply step inputs at V_{ref}.	P, P_{set}, Q, V_{ref}, V, V_{abc} phasors	PMU (30 sps minumum). Monitoring must include at least 1 min. of data prior to input and 5 min. after input.	$V(t)$ must follow $V_{ref}(t)$ over the entire 6 min. and have a settling time of 1 sec. or less. This requirement only applies for cases where $Q(t)$ does not reach a limit. For the above requirement, if $Q(t)$ reaches a limit then $Q(t)$ must remain at the limit until the demand allows for switching back to voltage control. The switching can be demonstrated by comparison of V_{ref} and $V(t)$. Must meet settling time for a variety of charge and discharge states. $Q(t)$ must have a resolution of 10% or less of rated output. A variety of step inputs shall be tested and must include a step input of 1% and 10% change in voltage. At least one step shall drive the system into $Q(t)$ saturation. $P(t)$ must remain at $P_{set}(t)$ during tests. $P_{set}(t)$ shall not vary with the step in the V_{ref} command. V_{abc} must remain balanced during transients.

Table 2.8: Steady-state voltage control tests, monitoring, and requirements.

Test Num	Test Name	Test Desc.	Monit'rd Var's	Monitoring	Requirements
1	System, Active Response (Closed Loop)	With the control system operating and the device connected to the grid, apply step inputs at V_{ref}.	P, P_{set}, Q, V_{ref}, V, V_{abc} phasors	DAQ (1 sps minumum). Monitoring must include at least 5 min. of data prior to input and 30 min. after input.	$V(t)$ must follow $V_{ref}(t)$ over the entire 35 min. and have a settling time of 1 min. or less. This requirement only applies for cases where $Q(t)$ does not reach a limit. For the above requirement, if $Q(t)$ reaches a limit then $Q(t)$ must remain at the limit until the demand allows for switching back to voltage control. The switching can be demonstrated by comparison of V_{ref} and $V(t)$. Must meet settling time for a variety of charge and discharge states. $Q(t)$ must have a resolution of 10% or less of rated output. A variety of step inputs shall be tested and must include a step input of 1% and 10% change in voltage. At least one step shall drive the system into $Q(t)$ saturation. $P(t)$ must remain at $P_{set}(t)$ during tests. $P_{set}(t)$ shall not vary with the step in the V_{ref} command. V_{abc} must remain balanced during transients.
2	System, Passive Response (Closed Loop)	Actively monitor system during grid interconnect. Capture significant voltage events within the system.	Q, V_{ref}, V, V_{abc} phasors	DAQ (1 sps minumum). Monitoring must include at least 5 min. of data prior to input and 30 min. after input.	$V(t)$ must follow $V_{ref}(t)$ over the entire event and with a minimum 1 min. delay. This requirement only applies for cases where $Q(t)$ does not reach a limit. For the above requirement, if $Q(t)$ reaches a limit then $Q(t)$ must remain at the limit until the demand allows for switching back to voltage control. The switching can be demonstrated by comparison of V_{ref} and $V(t)$. Events in both charge and discharge states must be captured. $Q(t)$ must have a resolution of 10% or less of rated output. V_{abc} must remain balanced during transients.

MVA rating of the transmission system.

A storage device operating under PF control will effectively vary the output reactive power to obtain the desired PF. A high-level perspective of the control system is shown in Figure 2.6 which is very similar to voltage control. Variables include:

- t = time.
- $P_{set}(t)$ = the set-point rms positive-sequence real power desired out of the device at time t.
- $PF_{ref}(t)$ = the reference rms positive-sequence voltage desired out of the device at time t.
- $u_e(t)$ = the control signal transferred to the storage device from the PF Control block. Often termed the excitation signal. The unit and form of this signal depends on the reactive power handling equipment employed by the storage unit.
- abc = three-phase electrical connection to grid.
- $P_e(t)$ = the true rms positive-sequence electrical real power out of the storage unit at time t.
- $Q_e(t)$ = the true rms positive-sequence electrical reactive power out of the storage unit at time t.
- $PF_e(t)$ = the PF measured somewhere in grid near the terminals of the device at time t.

A typical Power Control block is shown and discussed in Section 2.5.1. Performance and design of PF Control block is beyond the scope of this document. The high-level fundamental goal is to have $PF_e(t)$ track $PF_{ref}(t)$. The sensors for $Pe(t)$ and $Qe(t)$ are shown highlighted in yellow as it is not necessary for operation of the control systems, but, is necessary for monitoring the storage device's PF control ability.

Using Figure 2.6 as a reference, tests, monitoring, and requirements are provided in Table 2.9. Two tests are recommended. The first is an active test involving placing step inputs into the PF_{ref} command. A variety of step sizes and conditions should be tested. The second test is a passive one that involves capturing grid events. Events can include times of significant power changes such as planned ramps for the storage system.

2.5.4 Angle Stability Control

Angle stability relates to the electromechanical dynamic response of the system. It can focus on the transient stability of a given generator or sets of generators, or on the steady-state stability of the overall system. A given storage device's impact on angle stability is highly dependent on the device's location within the grid, the devices inherent capability, and the device's control system. Also, the assessment can be very complicated and time consuming. Entire multi-year studies are often employed to assess a device's impact on stability.

Monitoring and testing for angle stability applications is therefore extensive. Experiments would involve measuring and analyzing transfer functions and responses of the device to major faults for several system and device operating conditions. The variables monitored highly depend on the control system being employed. At minimum, time-synchronized sample rates near 30 sps are required. All device output variables (P, Q, f, V, V_{abc}) and all controlled variables must be monitored (for example, P_{ref}, P_{set}, V_{ref}, u, u_e).

As an alternative, we propose tests on the storage system to assess its potential to impact angle stability if it were located at a favorable location. That is, we will not test the impact on stability directly; but, will test the ability of the storage system to impact stability if it were to be placed in a location with a control system that could impact stability.

Table 2.9: Power factor control tests, monitoring, and requirements.

Test Num	Test Name	Test Desc.	Monit'rd Var's	Monitoring	Requirements
1	System, Active Response (Closed Loop)	With the control system operating and the device connected to the grid, apply step inputs at PF_{ref}.	P, P_{set}, Q, PF_{ref}, PF, V_{abc} phasors	DAQ (1 sps minumum). Monitoring must include at least 5 min. of data prior to input and 30 min. after input.	$PF(t)$ must follow $PF_{ref}(t)$ over the entire 35 min. and have a settling time of 1 min. or less. This requirement only applies for cases where $Q(t)$ does not reach a limit. For the above requirement, if $Q(t)$ reaches a limit then $Q(t)$ must remain at the limit until the demand allows for switching back to voltage control. The switching can be demonstrated by comparison of PF_{ref} and $PF(t)$. Must above 2 requirements for a variety of charge and discharge states. $Q(t)$ must have a resolution of 10% or less of rated output. A variety of step inputs shall be tested and must include a "small" change and a "large" change, and a change large enough to drive the system into $Q(t)$ saturation. $P(t)$ must remain at $P_{set}(t)$ during tests. $P_{set}(t)$ shall not vary with the step in the PF_{ref} command. V_{abc} must remain equal in magnitude, within the limits of the grid at the installation location.
2	System, Passive Response (Closed Loop)	Actively monitor system during grid interconnect. Capture significant events within the system that create significant changes in impedance at the point of interconnection.	Q, P, PF, PF_{ref}, V_{abc} phasors	DAQ (1 sps minumum). Monitoring must include at least 5 min. of data prior to event and 30 min. after event.	$PF(t)$ must follow $PF_{ref}(t)$ over the entire event and with a minimum 1 min. delay. This requirement only applies for cases where $Q(t)$ does not reach a limit. For the above requirement, if $Q(t)$ reaches a limit then $Q(t)$ must remain at the limit until the demand allows for switching back to voltage control. The switching can be demonstrated by comparison of PF_{ref} and $PF(t)$. Events in both charge and discharge states must be captured. $Q(t)$ must have a resolution of 10% or less of rated output. V_{abc} must remain equal in magnitude, within the limits of the grid at the installation location.

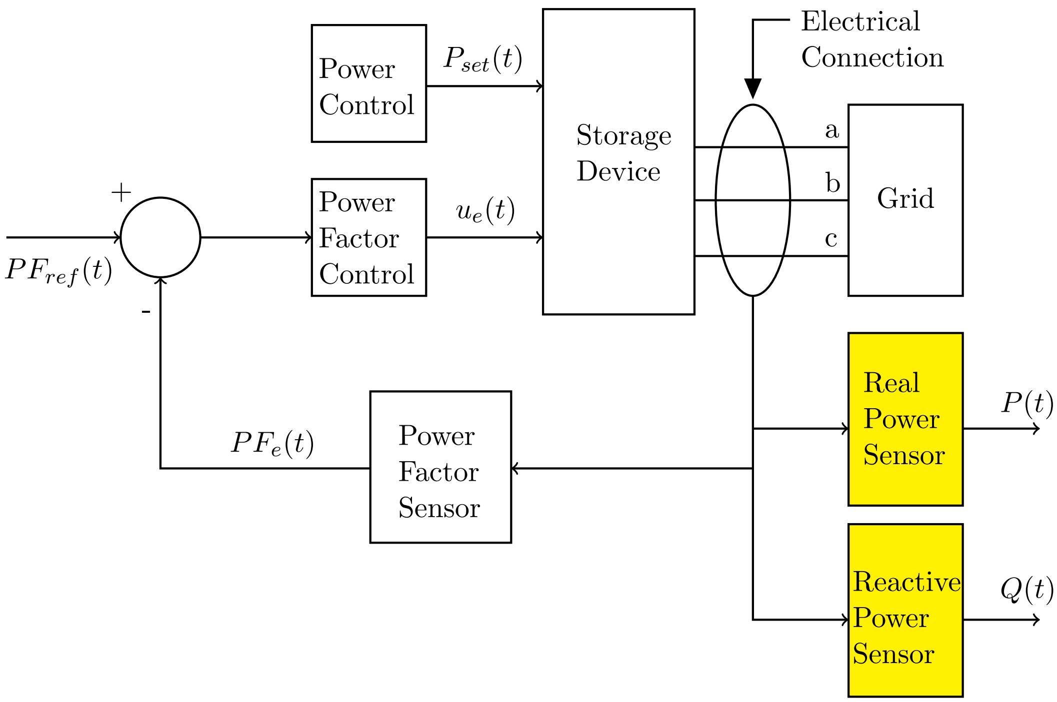


Figure 2.6: Generalized power factor control system.

To favorably impact stability, a storage system must respond to a change in P_{set} and/or Q_{set} independently. The response must be fast enough to impact the stability. Table 2.10 specifies two tests for $P(t)$. If one is to consider using $Q(t)$ as the controlled input to the grid, then these tests are conducted with inputs applied to Q_{set} with P_{set} held constant. Note that the table refers to Appendix A for a more detailed description of the inputs.

2.5.5 Sub-synchronous Resonance

Resonance occurs when two or more components of a system interact with one another at a specific and unique frequency to create undamped oscillations. When this special frequency is excited by an outside source catastrophic failure of the system may occur. Both purely electrical and purely mechanical systems can exhibit resonance behavior. When these two systems are interconnected, the resonance frequencies may sometimes coincide. Such can be the case when a steam-powered generator system (mechanical) interacts with a series compensated transmission line (electrical) resulting in a phenomenon known as sub-synchronous resonance (SSR).

As compared to hydro generators, steam-powered generator systems are normally designed to operate at high mechanical speeds. Also, when compared to combustion turbine generating systems, steam plants typically have many more, and much heavier, masses connected to a single shaft. A steam-powered generator assembly may consist of six turbine sections, a generator section, and an exciter section all on the same shaft and all spinning at 3600 rpm (angular shaft speed depends on the number of poles in the machine). This complex mechanical system exhibits dynamic properties including several natural modes of oscillation.

Similarly, electrical resonance frequencies are established when inductive reactance and capacitive reactance both exist in the same electrical circuit. In reality, both inductance and capacitance always exist in every electrical circuit. Usually the values are so small that the resultant resonance

Table 2.10: Angle stability control tests, monitoring, and requirements.

Test Num	Test Name	Test Desc.	Monit'rd Var's	Monitoring	Requirements
1	Storage Device, Direct Step Response (Open Loop)	Open any control system such that P_{set} and Q_{set} can be independently set. Apply step inputs to P_{set} while holding Q_{set} constant.	P_{set}, Q_{set}, P, Q, V_{abc} phasors, I_{abc} phasors	PMU (30 sps minumum). Monitoring must include at least 5 min. of data prior to input and 5 min. after input.	$P(t)$ must follow $P_{set}(t)$ over the entire 10 min. and must respond with the following specs (see Appendix A under Step Response): $T_r < 115$ millisec.; $T_s < 630$ millisec. and % OS $\leq 10\%$ Must meet settling time in both charge and discharge states. $P(t)$ must have a resolution of 2% or less of full scale. $P(t)$ must follow $P_{set}(t)$ with a steady-state accuracy of 2% of full scale. A variety of step inputs shall be tested and must include a step input of 10% and 100% of full scale in both charge and discharge. $Q(t)$ must remain at $Q_{set}(t)$ within 5% of full scale. V_{abc} must remain equal in magnitude, within the limits of the grid at the installation location. I_{abc} must remain equal in magnitude, within the limits of the grid at the installation location.
2	Storage Device, Direct Availability Response (Open Loop)	Open any control system such that P_{set} and Q_{set} can be independently set. Conduct two availability tests (see Appendix A), with P_{set} as the input while holding Q_{set} constant. Test parameters are: $f_p = 0.8$ Hz, 0.1 Hz; $\frac{A_{max}}{A_{min}} = \pm 100\%$ of FS, +50% of FS; +10% of FS; $A_{mid} = 0$; $T_{c1} \rightarrow T_{c4} = 1$ min.; $T_{p1} \rightarrow T_{p3} = 4$ min.	P_{set}, Q_{set}, P, Q	PMU (30 sps minumum). Monitoring must include at least 5 min. of data prior to input and 5 min. after input. Each test must be conducted three consecutive times for a total of 48 min.	$P(t)$ must follow $P_{set}(t)$ over an entire test and must respond with the following specs at each switching in the pulsing (see Appendix B): $T_r \leq 115$ millisec.; $T_s < 630$ millisec. and % OS $\leq 10\%$ Each test must be repeatable. This is tested by comparing the three identical tests. $P(t)$ must have a resolution of 2% or less of full scale. $P(t)$ must follow $P_{set}(t)$ with a steady-state accuracy of 2% of full scale. $Q(t)$ must remain at $Q_{set}(t)$ within 5% of full scale.

frequencies are very high and do not interfere with normal grid operation. However, when series capacitors are explicitly placed in a high-voltage transmission line to increase the real power capacity of the line it is possible that the resultant electrical resonance frequency established can interact with a resonance frequency of the mechanical shaft system of a steam-powered generator system.

Sub-synchronous resonance usually occurs at frequencies on the order of tens of Hertz. When SSR is present it manifests itself as a rapid fluctuation in current on the series-compensated transmission line. If it is detected at a power plant, the most common remedy for SSR is to trip the plant to protect it and then to restart with the series compensation removed. More sophisticated remedies, such as modulating or partially shorting the series compensation, are also currently employed at various locations on the bulk power grid.

It is possible for an energy storage system located near the troubled power plant to mitigate the effects of SSR. Such a storage device would need to absorb energy at the resonance frequency so that the resonance, while still present, is well damped. If a storage device were meant to damp SSR for indefinite periods it would be required to maintain this rapid charge/discharge rate for long periods of time.

The step response of a device providing an SSR damping benefit would need to have a rise time on the order of 0.01 seconds (see Appendix A), and must be capable of sustaining a charge/discharge cycle rate of 40 cycles per second for hours at a time to claim a long-term SSR mitigation benefit. A device may also claim an SSR protection benefit in which the benefit derived is to simply protect the power plant during a transient, i.e. short-term, SSR event while other mitigation action is taken. For example, an energy storage device may detect and mitigate SSR for a period of ten minutes while the bulk grid generation pattern is redispatched and the series compensation on the line in question is reduced. In this case, the redispatch and switching action on the part of the system operator is in response to the SSR detected by the storage device. For this type of SSR mitigation benefit the rise time must still be on the order of 0.01 seconds, but the sustained duration of the cycling can be as little as ten minutes.

The analysis techniques used to examine SSR requires point-on-wave data capture similar to the requirements for power quality monitoring (see Section 2.6). A high-level perspective of the control system is shown in Figure 2.7. Variables include:

- t = time.
- $P_{set}(t)$ = the set-point rms positive-sequence real power desired out of the device at time t.
- $P(t)$ = the true rms positive-sequence electrical real power out of the storage unit at time t.
- V_a, V_b, V_c = the a-phase, b-phase, and c-phase point-on-wave voltages at time t.
- I_a, I_b, I_c = the a-phase, b-phase, and c-phase point-on-wave currents at time t.
- ω = the shaft speed at time t, telemetered to the storage device over a communications channel, usually measured using a toothed-wheel attached to the generator shaft.
- $X(t)$ = a SCADA input from the control center indicating the status of the transmission line.
- abc = three-phase electrical connection to grid.

2.5.6 Shedding (under frequency or voltage)

Under-Frequency Load Shedding (UFLS) or Under-Voltage Load Shedding (UVLS) refer to a practice currently in use by most utilities to respond to last-resort emergencies on the bulk transmission grid. Reliability standards do not allow UFLS or UVLS to be used as a reliability tool for simple

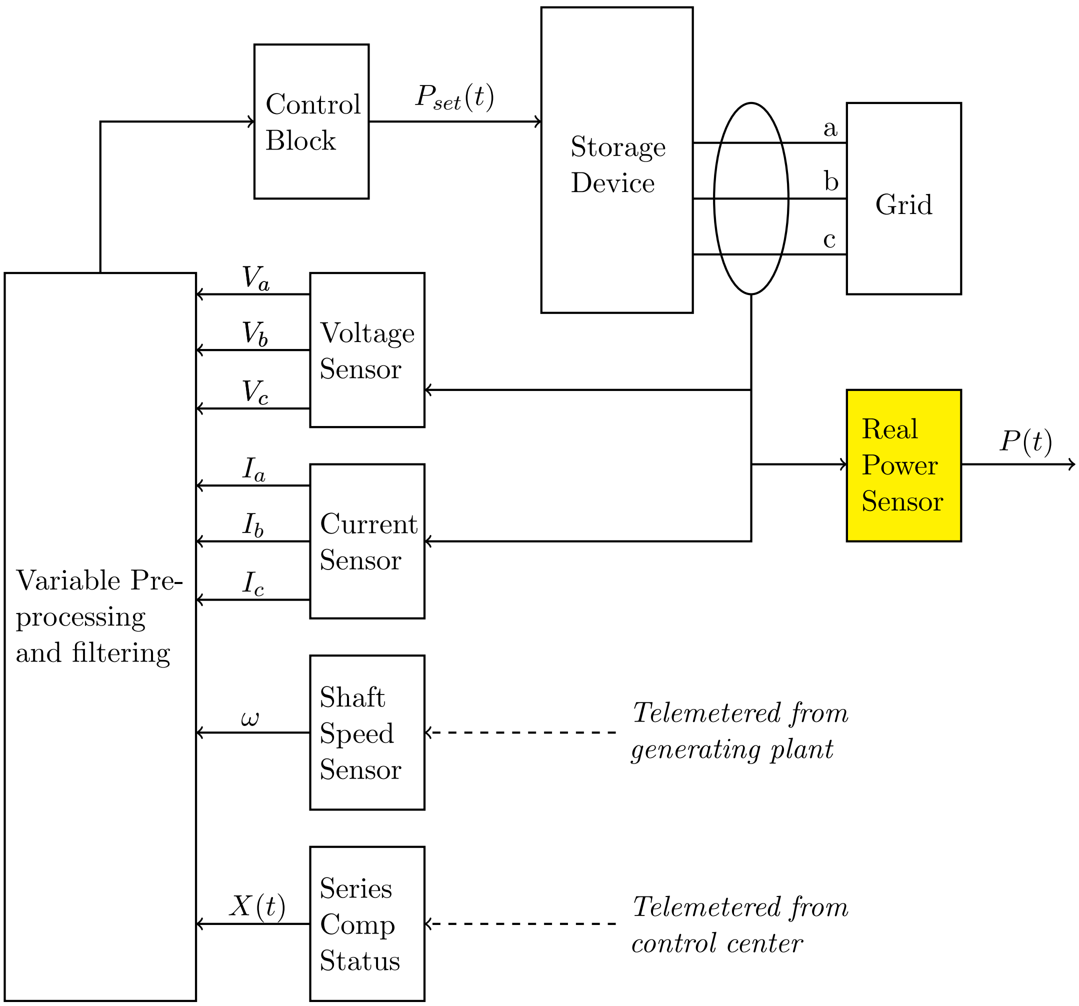


Figure 2.7: Generalized control block for SSR.

contingencies. They can only be used in circumstances where the system is in grave danger of collapse and extraordinary efforts are required to stabilize the situation.

UFLS relays normally trip an entire distribution feeder. They are most often set to actuate when system frequency drops to an unusually low value, for example 59.1 Hz in some parts of North America. A UFLS scheme is expected to drop a known amount of load measured in MW. If an energy storage device were present on the feeder, or in close proximity, it could inject the same MW of real power which would net the same result as if the feeder were tripped by UFLS. In other words, a storage device could replace the UFLS scheme.

Similarly, if the most appropriate response to an under-voltage event is to shed load then a storage device could offset the amount of load that would normally be shed with an UVLS scheme. It must be noted that a storage device can also provide reactive power (see Section 2.5.2). In cases of extreme under-voltage, it may be more appropriate to utilize the full capacity of the storage device to provide reactive power rather than using the device to inject real power to offset an UVLS scheme. In other words, the voltage control benefit and the UVLS benefit may be mutually exclusive.

The technical requirements for storage devices participating in UFLS and/or UVLS become somewhat ambiguous. Once initiated, traditional UFLS and UVLS operate extremely fast, for example 5-10 cycles or 1/6 of a second. However, the speed with which traditional UF(V)LS schemes operate is more an artifact of the speed of the circuit breaker rather than being derived from basic principles. In either UFLS or UVLS the physics of the phenomenon being manipulated is not so dependent upon speed. A rise time for the storage device on the order of 0.5 seconds should be sufficient for the intended purpose.

Testing for UF(V)LS response would involve triggering the shed command at a variety of operating and state of charge conditions. At minimum, one would need to monitor the set point real power, the actual real power being delivered (consumed) by the storage device, the actual frequency or voltage, and the trigger frequency or voltage. The storage device should get credit for the net change in real power when responding to the trigger event.

A PMU reporting at 60 samples per second, a sequence of events recorder, and/or a dynamic system monitor should be sufficient for the purpose of assessing the performance of a storage device claiming a UFLS/UVLS benefit. Data acquisition at reporting rates of 30 samples per second would provide marginally adequate information. Rates of less than 30 samples per second would be unacceptable. Data can be stored using triggered capture provided there is a buffer of pre-trigger data available in the recording device. Data need not be continuously recorded.

2.6 Quality and Reliability

Quality and reliability, for purposes of assessing monitoring needs, is a separate phenomenon from regional, or bulk grid, reliability as discussed in Section 2.5. Quality and reliability addresses any type of disturbance that may affect the ultimate end use, including poor power quality as well as feeder and branch circuit outages. High speed data acquisition is required to assess the benefits of storage with respect to end-use reliability. The data acquisition systems need not continuously collect data, but can be allowed to burst-record data sets when power quality problems are detected. The data acquisition system should be programmed to buffer an adequate amount of data prior to the disturbance for proper analysis.

Power quality generally refers to sags, surges, harmonics and other flaws in an otherwise purely sinusoidal voltage or current. Power is still available to the process, but the power is of such poor quality as to be unusable. Reliability, on the premises of the end user, refers to the provision of backup power during periods of time when power from the grid is unavailable. A reliable power source on a premise is commonly referred to as an uninterruptible power supply (UPS).

The benefit attributable to reliable power accrues, in part, to the value of the process preserved by providing reliable power during periods of time when grid power is not available or is of poor quality. Therefore, knowledge of the underlying process is important for assessment of the benefit. In terms of physical quantities, it is critical to retrieve point-on-wave data at a high sample rate to assess power quality or reliability.

2.6.1 UPS Applications

PQ monitoring equipment is appropriate for validating the benefits of a storage device claiming UPS capability. It is prudent to keep a continuous buffer of data and to only archive the data to disk if a reliability event is detected, that is to say if the voltage of the grid connection is degraded. The triggers should be set to capture point-on-wave data when the absolute value of grid voltage exceeds a threshold value.

An uninterruptible power supply (UPS) is a storage device intended to maintain a reliable supply of electrical energy to a critical end use. IEEE Standard 1366 defines two common metrics, System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI), used to measure reliability at the customer's meter. While SAIFI and SAIDI can vary significantly depending upon the geographic location of the utility and the utility's maintenance practices, the average customer might experience slightly more than one outage per year with an average total outage time of 1.5 hours (see, for example, Exelon Corp. Annual Report at http://www.exeloncorp.com/performance/investors/secfilings.aspx).

It is often the case that the critical load can be supplied by some fossil-based generator, for example a diesel backup generator, for outages that last more than a few tens-of-seconds. Therefore the performance requirements for an energy storage device intended to provide a UPS benefit is that the storage device seamlessly "picks up" the critical load for as long as it takes for either the utility to restore normal power or for the backup generation to safely come online and to pick up the critical load. The amount of energy capable of being delivered by the storage device must be sufficient to meet the demand of the critical load until either of the above conditions occurs. The speed with which the storage device responds must be commensurate with the ability of the critical load to tolerate outages.

For technical performance validation, it is not strictly necessary to record the power from the storage device. It is assumed that if voltage to the critical load remains within the tolerance of the equipment supplied then the storage device is delivering acceptable reliability. A high-level perspective for validating the delivery of this benefit is shown in Figure 2.8. Variables include:

- t = time.
- V_a, V_b, V_c = the a-phase, b-phase, and c-phase point-on-wave voltages at time t.
- SoC = the state of charge of the storage device at time t.
- abc = three-phase electrical connection to grid.

2.6.2 Harmonics

The IEEE Standard 519, along with IEEE Standard 1366 and other US and international standards, define power quality in terms of the usability of electrical energy. Harmonics represent one aspect of usability. Harmonics in a power system are strictly defined as energy in frequency bands that

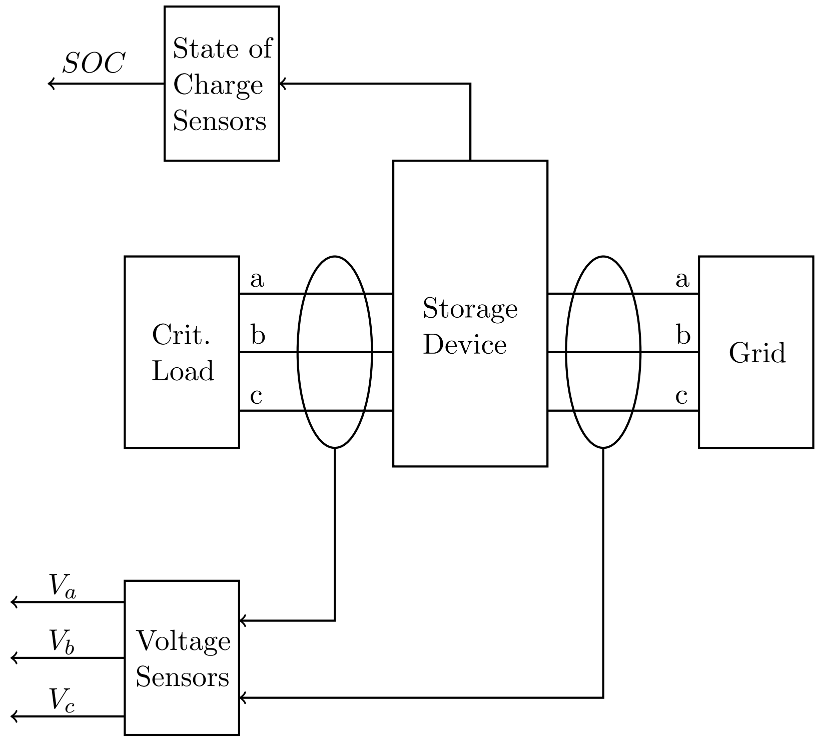


Figure 2.8: Generalized diagram for UPS validation.

are multiples of the fundamental which, in North America, is 60 Hz. However, the term can also be loosely applied to any situation in which unwanted frequencies interfere with normal operation of interconnected electrical equipment.

Because the cables, distribution feeders, and transmission lines associated with power grids impede the propagation of higher frequency energy, storage devices that are not in close proximity to the source of the problem will not be useful in providing a harmonic mitigation benefit to an affected end use. Sources of harmonic energy are typically "power electronic" devices connected to the grid. Power electronic devices have become more commonplace in the past decade. Examples include variable frequency drives, solar PV inverters, high-voltage DC (HVDC) terminals, Type 4 wind turbines, compact fluorescent lamps, and computing equipment. Excessive harmonics can overheat power delivery equipment, such as transformers, and can adversely affect microprocessors which are prevalent in nearly every industry.

A storage device capable of mitigating the effects of harmonics must have an extremely high bandwidth, or said another way, a very fast step response (see Appendix A). The IEEE Standard 519 specifies the maximum permissible energy in several frequency bands, the highest band measuring the 35^{th} and higher harmonics (2,100 Hz and higher). In most instances, the troublesome harmonics occur at the $3rd$, 5^{th}, 7^{th}, 9^{th}, 11^{th} and 13^{th} multiples of the fundamental. The 13^{th} harmonic equates to a frequency of 780 Hz on a 60 Hz system. For the purpose of assessing the benefits of a storage device for harmonic mitigation, it is assumed that the device must be capable of modulating either voltage or current at 780 Hz, that is to say the energy storage medium must be capable of modulating real power at 780 Hz and the grid interface must be capable of independently modulating either voltage or current depending upon the application. To accomplish the goal of modulating real power at a frequency of 780 Hz the storage device must have a rise time on the order of 100 microseconds.

To measure the effectiveness or performance of a storage device in mitigating issues associated with harmonics, only a PQ monitor or custom data acquisition device capable of sampling at 5000 samples per second or faster will suffice. The most straightforward method for determining the effectiveness of the device is to perform a test wherein the voltage and current harmonics can be measured in a test environment, or with the device in situ, both with the storage device in service and with the storage device out of service. After a device is placed in service it is not adequate to simply measure the amount of energy delivered by the device at harmonic frequencies to judge the device's effectiveness. The system impedance seen by the device at the harmonic frequencies of interest must also be measured to ensure that the device is providing benefit.

The next chapter presents a framework for evaluating the economic performance of grid connected electrical energy storage systems.

Chapter 3

Economic Performance Analysis

3.1 Introduction

New, non-traditional means of maintaining the required instantaneous balance between electricity demand and supply are gaining ascendancy. The traditional perspective of maintaining that balance, mostly from the supply side, has given way to the perspective that both consumers and suppliers can play important roles in maintaining this balance and simultaneously reduce the costs incurred by both parties. Electrical energy storage (EES) systems constitute one of those new means of balancing. While some EES technologies have been around for a very long time (e.g., pumped hydroelectric storage), others, such as flywheels, are emerging. As with most new investments, evaluating these new technologies can be challenging mostly because of increasingly thorough understanding of the physics of electric systems has identified many subtleties that must be considered. EES, akin to load in their charging phase, present additional considerations in their evaluation. The policy environment has also become complex and nuanced with the simultaneous existence of differing business models in the industry.

The potential benefits of an EES storage system stem from one of the four activities:

- Sourcing real power (discharging)
- Sinking real power (charging)
- Sourcing reactive power
- Sinking reactive power

For those unfamiliar with the terms“sourcing” and “sinking”, sourcing refers to the flow out of a device while sinking refers to the flow into a device. None of these capabilities are unique to EES. For example, traditional generation is capable of supplying real power. Loads are capable of sinking real power. Capacitor banks are capable of providing reactive power. Some types of traditional generation are capable of absorbing reactive power. EES systems are unique in their ability to provide all four capabilities

A discussion of the relationship between the terms energy, power, and capacity may help to clarify the discussion in this chapter. Two critical parameters of an EES system are the rated power and energy. Energy is defined as the capacity of a physical system to perform work. Power is defined as the rate of change in energy. These relationships are captured by the following equation.

$$Energy = \int_0^T Power(t)dt \tag{3.1}$$

EES applications may be categorized by their energy and power requirements, as shown in Table 3.1.

Table 3.1: Power and Energy Criteria.

	Low Energy	**High Energy**
Low Power	Example: Short term distribution level energy storage (minutes)	Example: Long term distribution level energy storage (e.g. days).
High Power	Example: damping inter-area oscillations. Output can be 10's to 100's of MW, zero net energy.	Example: large pumped hydro facility capable of supplying 100's of MW for 8-12 hours.

Since energy is the integral of power over time, the difference between many low energy and high energy applications is simply time. For example, wind ramp rate limiting for a small wind farm could be classified as low power and low energy. Wind firming for the same wind farm could be considered low power, high energy if the EES system is required to replace lost wind generation for long periods of time (e.g. several days). There are no firm guidelines for energy and power thresholds. Often, they are technology dependent. A 50 MWh pumped hydro system might be considered "low energy" relative to other pumped hydro systems. A 50 MWh lithium battery system might be considered "high energy" relative to other lithium battery systems.

Other new, non-traditional means of supply and demand balancing with similarities to EES include "demand response" (DR), "energy efficiency" (EE), and "distributed generation" (DG). Demand response is the willingness of consumers to reduce their electricity consumption during times of peak consumption, often shifting it to off-peak times. Energy efficiency refers to improvements in electric consuming devices to reduce their electric consumption while maintaining or improving output performance. Distributed generation is the practice of geographically dispersing smaller generation units around the load center as compared to the large, central station generation plant.

For various reasons these other non-traditional means are further along in their diffusion throughout the industry. Therefore, processes have been adopted[1] to standardize their evaluation. This is fortuitous because we can use many of the evaluation principles and methodologies in the promotion of a standard for evaluating EES technologies [18, 19, 20].

3.2 Sequential Analysis Process

A methodology for assessing investment cost-effectiveness that can compare new, non-conventional solutions with conventional solutions is necessary to produce technically defensible analyses that highlight comparative costs. A four-step process for down-selecting a set of technological and possibly non-technological solutions is recommended.

Step 1 Identify required services and solution concepts.

Step 2 Identify feasible Functional Uses (see Table 3.2).

Step 3 Identify and asses grid impacts including incidental benefits.

Step 4 Develop energy storage business cases.

[1] Or they are in the process of adoption.

Table 3.2: Functional Uses for EES systems and their associated value metrics.

		Functional Use	Value Metric	Analysis Methods
Bulk Energy	1	Electric Energy Time-Shift	The price differential between energy price during charge and discharge. This includes: • arbitrage • renewable energy firming and integration • electric supply capacity: The avoided cost of new generation capacity (procurement or build capital cost) to meet requirements.	Production cost modeling; optimization using historical and projected data; use specific valuation tools; long term planning models.
T&D Services	2	Transmission Upgrade Deferral	The avoided cost of deferred infrastructure to address the issue.	Long term planning models.
	3	Distribution Upgrade Deferral	The avoided cost of deferred infrastructure to address the issue.	Long term planning models.
	4	Transmission Voltage Support	The avoided cost of procuring voltage support services through other means.	Power flow modeling
	5	Distribution Voltage Support	The avoided cost of procuring voltage support services through other means.	Power flow modeling
Reserve Services	6	Synchronous Reserve	*Regulated environment*: the avoided cost of procuring reserve service through other means. *Market environment*: the market price for synchronous reserve.	Production cost modeling; optimization using historical and projected data; use specific valuation tools.
	7	Non-Synchronous Reserve	*Regulated environment*: the avoided cost of procuring reserve service through other means. *Market environment*: the market price for non-synchronous reserve.	Production cost modeling; optimization using historical and projected data; use specific valuation tools
	8	Frequency Regulation	*Regulated environment*: the avoided cost of procuring service through other means. *Market environment*: the market price for frequency regulation service.	High resolution production cost modeling; optimization using historical and projected data; use specific valuation tools.
Customer	9	Power Reliability	The avoided cost of new resources to meet reliability requirements.	Distribution modeling: power flow; use specific valuation tools; simple internal modeling.
	10	Power Quality	The avoided cost of new resources to meet power quality requirements, or avoided penalties if requirements not being met.	Distribution modeling: power flow; use specific valuation tools; simple internal modeling.

3.2.1 Step 1: Required Grid Services Addressed by Solution Concepts

Develop a list of required grid services, identify specifications, and define characteristics of the potential solutions. The solutions may include EES as well as other types of technological or non-technological sources. EES may have advantages that conventional solutions lack including very fast response and ramp times as well as the ability to operate at non-unity power factor. The possibly unique advantages of EES have the potential to solve problems on the grid in different contexts; other solutions may have a different set of advantages. The first step of the investigation is to ask the questions: "What is the grid operational or planning problem?" and "What technological or non-technological solutions are available?"

After identifying a needed grid service the technical requirements can be communicated to actual stakeholders and decision-makers to determine the metrics being considered, the minimum solution criteria, and the alternative solution(s) to the problem. The technical criteria for an energy solution can then be determined based on the site-specific information available. The value of the energy storage solution can be determined based on the avoided cost or expected revenue of the chosen grid service. The term grid service refers to a defined need for power or energy to solve a grid issue and contains two critical elements:

1. Technical objectives and minimum requirements

2. Calculable value

3.2.2 Step 2: Identifying Feasible Functional Use Cases

A functional use case is a technically feasible combination of grid services. Each functional use case should have an "anchor" service that drives the incentive for a grid solution; this could be a distribution investment deferral that uses a technology or other grid adjustment to delay or eliminate an expensive transformer or line upgrade.

After grid service requirements have been determined for the anchor service, the relative value of the anchor service should be investigated to determine whether it could potentially support a cost-effective use case. Depending on the size of the upgrade investment, the load characteristics (e.g. frequency and duration of peaks), and available technology or operational options this could be a promising anchor service. Tools are available for investigating the anchor service. A tool would need the capability to run a time-series simulation and cost-benefit calculation for the anchor service based on the grid service requirements and underlying site-specific data that the user can provide[2]. Other grid services that are compatible technologically with the anchor service can then be investigated.

3.2.3 Step 3: Monetary and Non-monetary Benefits

The purpose of this step is to determine how different solution options affect the key system-wide metrics listed below:

1. Monetary benefits/costs - energy and ancillary services prices

2. Non-monetary benefits/costs

   (a) Asset utilization and generator operation

[2]Sandia/Kema-DNV's ES Select is an internet tool available to perform "down select" analyses at a high level and the EPRI ESVT3.0 tool has simulation capabilities that can perform some of the required operations

(b) T&D losses

(c) Environmental impacts (e.g. GHG emissions)

Benefits may be monetary in that they affect prices for energy and ancillary services. They may also be nonmonetary if the solution option affects other asset utilization, changes T&D losses, or has an effect on environmental metrics. Incidental benefits need not be unintended but if the benefit cannot be modeled as a grid service it does not drive the energy storage dispatch and therefore is incidental to the operation of the investment alternative under consideration. Incidental benefits may result from a combination of the asset dispatch and other characteristics of the electric system leading to the observation that incidental benefits could be costs.

The steps in the process involve:

1. Assess a baseline scenario with no additional energy storage—the "no action alternative";

2. Define and simulate likely grid deployment scenarios for alternative investments, informed by use case cost-effectiveness;

3. Tabulate the monetary and nonmonetary benefits and costs of interest in each scenario. At the end of this process, the incidental benefits and costs of storage deployment will be quantifiable.

Particularly in a regulated environment nonmonetary benefits and costs may be relevant to highlight differences between solution options. These are often referred to as "externalities" by economists. This means the benefits and costs have no opportunity to be reflected in prices at which resources are traded. These externalities, such as changes to asset utilization or changes to transmission or distribution losses as itemized above, can occur within the electric system under evaluation. If any of the alternatives under evaluation have these kinds of effects, they should be identified and quantified as much as possible. So, for example, if an alternative allows greater asset utilization of other assets on the system the increase in capacity factor or other utilization measure can be identified. Transmission and distribution losses can be handled similarly. It is possible that changes in capacity factors could be transformed into dollar values with particular detailed analysis. This is also true for changes to transmission and distribution losses.

Externalities that occur outside the electric system are more than likely to be environmental or other types of externalities that affect the public at large. Guidance is somewhat similar in these situations in that the externalities should be identified and quantified to the extent feasible—tons of CO_2 reduction for example. Using guidelines promulgated by the federal government such externalities can then be converted to monetary units based on widely accepted and vetted parameters. For example, the report of the Interagency Working Group on Social cost of Carbon, United States Government can be used to apply monetary values to carbon dioxide [21].

3.2.4 Step 4: Investment Business Cases

The final step of assessing the cost-effectiveness of alternatives is to evaluate the technology and non-technology alternatives for functional use cases. This stage involves the organization of data and information to conduct financial and accounting analyses. It may also involve the introduction of policy and regulation considerations that might be taken into consideration in a broader decision making process that goes beyond the strict financial and economic analysis presented in business cases[3]. This involves assembling data into a form in which it can be manipulated to produce the

[3] The EPRI ESVT3.0 is a project financial analysis tool energy geared toward EES evaluation and is capable of supporting business case simulation. It includes the capability to run discounted cash-flow and utility revenue

desired investment analyses. It also involves choosing *investment criterion* that will be applied to choose the best alternative investment. This process is the subject of the next section.

3.3 Fundamental Evaluation Principles and Methods

Investment analysis is about choosing among alternatives. There are always alternatives available. Even in the *de minimis* case, the "no action" alternative, is always an option. Complications arise from the fact that investment alternatives may be quite different in their scale, the time distribution of benefits and/or costs, the level of risk, and in a variety of other possible ways. The analysis is further complicated by the fact that different types of organizations may find that certain methods are more amenable to circumstances they find important while other types of organizations may prefer yet another approach.

Several different approaches could be used to evaluate the cost effectiveness of EES and alternative investments. Among the alternatives for organizing the information and data are the business case approach and integrated resource planning. Except for relatively large investments in EES systems neither of these approaches is likely to be sufficiently fine-grained to properly measure the benefits and costs of EES investments that are likely to have smaller impacts on a system. An alternative means to evaluate smaller investments having smaller impacts is to employ a method based on avoided (marginal) costs.

The "avoided cost" principle was first propounded in the Public Utility Regulatory Policy Act of 1978 as the appropriate criterion for use in evaluating competing technologies. The Federal Energy Regulatory Commission defined that principle as the "incremental capacity and energy cost a utility would have incurred if they had built their own capacity rather than purchase energy from a qualifying facility." While there was controversy over how that principle was applied in some cases it remains appropriate for evaluation of EES technologies [22].

This principle derives from the economic concept of opportunity cost, which holds that the value resulting from undertaking action "A" is equivalent to avoiding cost by not undertaking "B". As is evident from the above statement the terms avoided cost and opportunity cost are relative and have meaning only in reference to some base action or condition. The principle is effective only in comparing alternative courses of action.

3.4 Evaluation Perspectives

One important fact to keep in mind in evaluating any investment in the electric utility industry is the business model that pertains to the particular geographic area in which the investment is to be located. Generally one can distinguish between the "state-regulated, vertically integrated utility" business model and "market resource allocation areas". This is important because evaluations may need to be structured somewhat differently depending upon the business model existing in the area of interest.

Vertically integrated utilities' investment evaluations turn on cost differentials between two or more alternatives since the business objective of the entity is likely to be some variant of cost minimization together with the requirement to serve load. Such an entity could also perform revenue requirements analyses to demonstrate the impact of the investment on electric rates. This approach also resonates with regulators whose constituents' interests are served by keeping electricity prices as

requirement analyses, and can generate financial proforma statements including debt, equity, and tax assumptions. Policy scenarios, such as simulating the effect of an investment tax credit, can be run easily by adjusting financial and economic assumptions.

low as possible. If the utility commission approves the investment request, the utility is permitted to add the value of the investment to the "rate base" (base on which the utility may earn its allowed rate of return) and return of invested funds over the life of the investment is then somewhat guaranteed. This may mean that the evaluation needs to consider a longer list of alternatives to demonstrate least cost. It could also be that the utility commission requests information on the non-market benefits of the proposed investment as well. It is likely that the decision to move forward with the investment will turn on a combination of considerations beyond the narrow profitability of the investment. Utility commission approval is normally sufficient to obtain debt funding from capital markets.

An independent third-party investor, such as an independent power producer (IPP), might propose an investment in a specific regulated utility's service territory. In such a case, three independent but related types of analyses might be performed: analyses examining the profitability of the investment to the developing entity, analyses that the investor would use to convince the utility of the merits of the investment, and analyses that would help the utility convince its regulatory commission on the merits of the investment.

In contrast, entities doing business in areas characterized by wholesale market resource allocation are in competition with each other to supply the market demand for electricity. They offer their resource into forward auction-type markets at specified offer prices. If their offers are accepted (cleared in the market) they will supply a portion of the market demand. If their offer price is too high they will not be cleared and cannot supply the market. Unless such entities are operating under a Power Purchase Agreement or a Tolling Agreement, they operate on the potential for profit but have no backstop guarantee that they will be profitable. Investment evaluation for this type of entity follows a more standard "business case" approach. Evaluation in this circumstance is likely to be narrower in that the firm will already be in possession of a technology and will want to determine whether a profit can be made in the application of that technology to provide a particular service.

In the evaluation approaches set out below, we make an effort to consider the effect of the business model and the organizational nature of the entity making the proposal on the type of analyses that are likely to be performed and on the criteria used to make decisions on the investment.

State-regulated, Vertically Integrated Utility (VIU) Business Model

This is the traditional regulated utility business model that originated in the early decades of the 20^{th} Century and remains in use in the southeastern and western regions of the U.S. It consists of organizational entities that functionally bundle generation, transmission, and distribution into one organization. Such organizations are usually privately owned but their operations are subject to public utility commission oversight. They must obtain approval from their regulatory commission for new capacity investment and changes in the "rates" (prices) charged to their customers.

Market Resource Allocation Business Model

These areas are characterized by unbundled generation and more open access to organized wholesale markets by non-traditional entities (Independent power producers, merchant plants, etc.).They are subject to Federal Energy Regulatory Commission (FERC) regulation of market rules and protocols and to interstate commerce of electricity when it enters the transmission network. Formerly vertically integrated utilities that have divested generation and serve the final consumer in the role of "load serving entities" (LSE) supply consumers at rates regulated by state regulatory commissions. Given this regulatory structure the cumbersome phrase "market resource allocation" areas is used to distinguish this business model from the state-regulated, vertically integrated utility business model.

3.5 Evaluating EES Functional Uses

Step 2 of the evaluation process described above recommended identifying functional use cases to be evaluated. Table 3.2 includes a list of Functional Uses that EES technologies can provide at grid scale along with the metrics that should be used in the evaluation of a device in a specific location providing the identified Functional Uses.

3.6 Effect of Organization Type on Investment Analysis

Entities proposing to invest in EES are most likely to be privately owned firms whose shares are publicly traded or at least traded OTC; they may be IPPs, merchant plants, VIUs or any of a variety of other business entities. As private sector entities, they need to pay particular attention to the effect of their decisions on shareholder or investor value. They can do this by ensuring investment opportunities meet their internal decision criteria before proceeding. They may examine investments as to their rate of return on investment, rate of return on equity, internal rate of return, discounted cash flow, short-term and longer-term cash flow projections, and other investment criteria they may choose to apply.

After determining that proposed investments meet their criteria and are in the interests of the entity, they may then perform other investment analyses which support advancement of the proposal. At this juncture the comparison of a specific technology alternative to other possible alternatives could be necessary or desirable. In the case of the VIU, it may be necessary in making the case before the regulatory commission that this particular technology is the lowest cost alternative to solve the problem. In the case of an IPP, it may be necessary to demonstrate to a utility from which the IPP is seeking a power purchase agreement (PPA) that this is the best alternative source of energy. Whatever the particular circumstances of the case are, analysis of alternative solutions is required.

3.7 Which Type of Investment Analysis?

Investment criteria are used for making decisions in regard to specific investments. A number of criteria are available and have typically been used for accepting or rejecting specific investments or ranking investments for various purposes. Table 3.3 identifies the most commonly used criteria, and provides a brief description of each together with the units in which the criterion is expressed. The most commonly used of the ten criteria listed in Table 3.3 are NPV, B/C, and LCOE.

Table 3.3: Typical Investment Criteria [6].

Investment Criterion	**Typical Acronym**	**Brief Description**	**Units**
Net Present Value	NPV	Discounted sum of future benefits minus costs	Present Value Dollars
Total Life Cycle Costs	TLCC	Sum of future costs over project life	Dollars
Revenue Requirements	RR	Future revenue required to offset all cost (regulated environment)	Dollars
Levelized Cost of Energy	LCOE	Annuitized cost per energy unit	Dollars/Energy Unit
Internal Rate of Return	IRR	Rate of return that equalizes present value of receipts and expenditures	Percentage
Modified Internal Rate of Return	MIRR	Same as IRR except regarding reinvestment at discount rate	Percentage
Simple Payback	SPB	Number of years to accumulate revenues equal to investment outlays	Years
Discounted Payback	DPB	Same as SPB except revenues & investment outlays are discounted	Years
Benefit-cost ratio	B/C	Discounted total benefits divided by discounted total costs	Fraction, decimal
Savings to Investment Ratio	SIR	Modified B/C ratio where principal investment costs are in denominator and all other costs are subtracted from benefits in numerator	Fraction, decimal

For internal analyses, such as described above, firms will likely restrict their models to the consideration of actual monetary cash flows—future streams of revenues and costs. In regulated environments where revenues are fairly fixed ("sticky" regulated rates), decisions will likely turn on the difference in costs between different technologies. In market resource allocation areas, the revenue streams will result from offering assets into auction markets. Discounted cash flow will be a main analysis methodology and net present value (NPV) will be the investment criterion. Any project with a positive NPV merits further consideration.

Other investment criteria are in common use and there is really no absolute guideline as to which is the most appropriate, particularly when considering all possible circumstances. NPV probably comes closest to this ideal. While NPV is perhaps the most commonly used criterion, particularly in private sector firms, levelized cost of energy (LCOE) is also widely used, particularly in regulated environments. Fortunately, the question of which investment analysis approach and which investment criterion is most appropriate has been reported in the literature. Table 3.4 is an example and is adapted from a lengthier table appearing in [6].

Table 3.4: Guideline Suggestions for Investment Criteria Applicability [6].

Investment Decision	**NPV**	**LCOE**	**B/C**	**IRR**	**RR**
Accept or reject	A,C	A,C	A,C	A,C	NR
Select from mutually exclusive alternatives	R	NR	NR	NR	A
Ranking	A	A	NR	NR	A

Legend: **A**: Acceptable, **C**: Common, **NR**: Not Recommended.

Other key insights and recommendations from [6] include:

- Levelized cost of energy, internal rate of return, modified internal rate of return, simple payback period, discounted payback period, benefit-cost ratio, savings-to-investment ratio are not recommended for analysis of mutually exclusive alternatives because these measures do not normalize for the scale of different investment alternatives.
- Revenue requirements (RR) analysis is recommended for investments in a regulated environment. (*It is noted that RR analysis is generally required for any regulated utility to submit to its commission. However, in internal decisions, the utility will likely employ other analyses and measures to assure its executives and board that a given investment is in the best interest of the organization.*)
- Only NPV is recommended as an investment criterion for decisions on mutually exclusive projects. Incremental B/C analysis is equivalent to maximizing the NPV (See Appendix B).

3.7.1 Discounted Cash Flow/Net Present Value

A simple generalized formula for calculating discounted cash flow is given by:

$$DCF = \sum_{i=1}^{N} \frac{R_i - C_i}{(1+r)^i} \tag{3.2}$$

where

DCF	discounted cash flow (net present value)
R_i, C_i	revenue and cost in period i
r	discount rate, interest rate
N	number of periods

This is a straightforward type of analysis that is performed in many areas of business including investments of real capital as well as financial investments.

3.7.2 Calculating Levelized Cost of Electric Energy

Levelized cost of energy (LCOE) is the cost per unit of energy produced (or saved) by the system over the analysis period that will sum to the total life cycle cost when discounted back to the base year. It is used to compare alternative investments even if they have different scales of operation, different investment, and/or operating periods. A generalized formula for LCOE is [6]

$$LCOE = \frac{\displaystyle\sum_{i=1}^{N} \frac{C_i}{(1+r)^i}}{\displaystyle\sum_{i=1}^{N} \frac{Q_i}{(1+r)^i}} \tag{3.3}$$

where

$LCOE$	levelized cost of energy
C_i	cost associated with period i
Q_i	energy output or energy saved in time period i
r	discount rate, interest rate
N	number of periods

Total life cycle cost ($TLCC$) is calculated as follows:

$$TLCC = \sum_{i=1}^{N} \frac{C_i}{(1+r)^i} \tag{3.4}$$

The costs in any time period include investment costs, finance charges, potential salvage value, non-fuel operations and maintenance costs, replacement costs, and fuel costs.

3.7.3 Relationship between DCF/NPV and LCOE

There is a clear relationship between these two investment criteria. When the incremental revenues are zero or are unchanged across a number of different technologies, then the alternative technologies can be compared based on the NPV of their costs[4]. Levelizing a stream of benefits or costs (or their net amount) is a process in which (i) the NPV is calculated using the stream of future receipts and or payments; and (ii) calculating the equal annual payment whose present value equals the original NPV. Therefore, the investment criteria NPV and LCOE are equivalent. The convenience of LCOE is that its units are in terms of dollars per unit of energy (e.g., $/kWh) which allows direct comparison between projects of different scale or technology. In contrast, PV or NPV is in units of money but they're not the units of money with which we're familiar—they're not nominal dollars.

[4]See Appendix B of this report.

3.7.4 Effect of Nonmonetary Costs and Benefits

The literature describing the potential benefits of EES devices emphasizes the nonmonetary, incidental benefits that may be conferred by investments in these devices. In fact, most of the other technologies that compete with EES devices to provide Functional Uses will similarly provide nonmonetary benefits. There may be differential amounts of incidental benefits provided or costs incurred by the alternatives so this needs to be carefully evaluated for each option. For example, a combustion turbine will likely provide some incremental incidental benefits of GHG emissions compared with a coal plant but the turbine will not provide as large a benefit stream as a large battery EES system.

3.8 Functional Use Evaluation Approaches

This section sketches the process and key features of an evaluation of each of the Functional Uses listed in Table 3.2.

3.8.1 Electric Energy Time Shift

This functional use is accessible only to EES systems; systems that have the capability to charge the storage device when off-peak energy price is relatively low and discharge the stored energy when energy price is relatively high, earning the differential to contribute to capital and O&M for the system. In an unregulated environment this produces a net revenue stream for the asset owner. In a regulated environment the utility can potentially reduce cost of transmission congestion by engaging in energy time shift. When energy demand is peaking, it is necessary to utilize even the most expensive generators in the utility's fleet. EES could potentially be substituted for more expensive generators and reduce the utility's cost of operation.

Key Variables/Parameters Required for Evaluation in Regulated area
The following items should be used in the evaluation:

- Levelized annual capital cost of EES technology $/kw
  - Technology specific assumptions such as useful life, number of cycles per year, periodic replacements (such as for batteries), depth of discharge, etc.
  - Charge/discharge efficiency of EES device
    - Can be handled by estimation of charge versus discharge hours during year
- Levelized annual cost of O&M of EES technology $/kwh-yr
  - Requires forecasting hours of actual operation per year—capacity factor
  - May necessitate an optimization or repeated simulation to determine the number of hours of operation at which cost is minimized
- Financing assumptions
  - Debt/equity ratio
  - Cost of capital
- Other assumptions regarding financial, accounting, and economic variables
  - Depreciation assumptions

    - Tax credit programs
    - Income tax assumptions

- Credits for reduction in transmission congestion—nonmonetary incidental benefits

It is assumed that this information will be available for each of the Functional Uses. It will not be repeated for each one.

Key Variables/Parameters for Evaluation in Market Resource Allocation Area

- Estimated revenues from sales of energy at peak prices ($/kwh)
- Estimated costs from purchases of energy at off-peak prices ($/kwh)
- Annual net revenue (revenue minus cost) that could be earned from electricity sales into AS markets and/or other services that are compatible with use of the resource for energy time shifting ($/kwh)
- Credits for reduction in transmission congestion FTRs

Organizing the Investment Decision

VIU Business Model

EES systems are the only supply side technology with the capability to move energy through time—the equivalent of peak shaving. The only other alternative that is comparable to EES in this functional use is demand response. Accordingly, the alternatives to be evaluated are the EES system and a program to shift demand from peak to off-peak times. The benefit of reducing peak demand for the VIU is reduction in the cost of operating the most expensive generators in the fleet. Since this benefit would be the same for both alternatives, a direct comparison of the LCOE of the EES system and the LCOE of a demand response program could be made.

Market Resource Allocation Model

For an unregulated firm the decision to invest in an EES system with the capability to shift energy in time is governed by the excess of annual net revenue (revenue minus cost) from the sale of electricity over the annual levelized cost of energy calculated for the particular EES system being evaluated.

3.8.2 Transmission Upgrade Deferral

The benefit to be achieved by deferring an investment to upgrade transmission is the avoided financing and other equity cost of the upgrade for the duration of its deferral. The question to pose is "Will the upgrade deferral be temporary or permanent?" The proper evaluation methodology depends upon the intent of the deferral. If the deferral is temporary, the proper approach is to compare the time stream of benefits and costs of the project installed immediately versus the time stream of benefits and costs with the project delayed for a specific period of time. In this case, the evaluation would be of these two project timing alternatives with a third alternative which incorporates the means of achieving the delay. Presumably this would include some form of EES technology, conventional technology, or a non-technology solution.

Organizing the Investment Decision

VIU Business Model

This approach would compare the incremental cost obtained from subtracting the cost of the deferred and un-deferred options to the $LCOE$ of the third alternative. If the deferred upgrade is viewed as a permanent solution then the avoided cost is the entire value of the project that was permanently deferred. It is assumed that the third "next best" alternative to EES is a combustion turbine. Thus a combustion turbine could be the "benchmark" or "base case" alternative and its LCOE would be evaluated using the LCOE calculator. EES and other alternatives would then be compared on the same LCOE basis.

Market Resource Allocation Model

In a market setting the industry is functionally unbundled with the transmission network owned by different entities than those that operate it. In this environment, it is unclear how an entity would organize an effort to substitute some other resource or technology for a transmission upgrade. Different models and approaches are identified and discussed in the literature. With the exception of ERCOT, no general solutions have been achieved [23, 24].

3.8.3 Distribution Upgrade Deferral

The benefit achieved by deferring an investment to upgrade distribution is the avoided financing and other equity cost of the upgrade for the duration of its deferral. The question to pose is "Will the upgrade deferral be temporary or permanent?" The proper evaluation methodology depends upon the intent of the deferral. If the deferral is temporary, the proper approach is to compare the time stream of benefits and costs of the project installed immediately versus the time stream of benefits and costs with the project delayed for a specific period of time. In this case, the evaluation would be of these two project timing alternatives with a third alternative which incorporates the means of achieving the delay. Presumably this would include some form of EES technology, conventional technology, or a non-technology solution.

Organizing the Investment Decision

VIU Business Model

This approach compares the incremental cost obtained from subtracting the cost of the deferred and un-deferred options to the LCOE of a third alternative. If the deferred upgrade is viewed as a permanent solution, then the avoided cost is the entire value of the project that was permanently deferred. It is assumed that the third "next best" alternative to EES is considered to be a combustion turbine. Thus a combustion turbine could be the "benchmark" or "base case" alternative and its LCOE would be evaluated using the LCOE calculator. EES and other alternatives would then be compared on the same LCOE basis.

Market Resource Allocation Model

In a market setting the industry is functionally unbundled with the distribution system typically still owned by the regulated utility that existed before restructuring. In a few states, efforts to unbundle the retail market are under way. Given this structure, it is likely that the distribution network ownership entity would treat the investment much like it would under the regulated utility mode. This would essentially involve a "rate basing" initiative.

3.8.4 Voltage Support for Transmission and Distribution

These two Functional Use categories are handled similarly to Transmission and Distribution Upgrade Deferral. In fact, providing voltage support involves the same set of options as taking actions to defer upgrades.

3.8.5 Reserves: Synchronous, Non-synchronous, Frequency Regulation, Power Reliability, Power Quality

These four functional use categories are essentially equivalent to an option to provide power/energy as required by the application. For these Functional Uses, EES systems are likely to encounter their stiffest competition from conventional technologies. EES systems are energy-limited compared to conventional resources. Nevertheless, they do have the advantage of extremely fast and accurate response times, which may be valuable to their use as reserves. Regulation reserve is the use commonly mentioned, and energy storage is commonly employed in uninterruptible power supply (UPS) applications.

In market resource allocation areas, rules are evolving and becoming more accommodating to EES systems. Offering an EES asset in wholesale reserve markets in an unregulated environment produces a net revenue stream for the asset owner. In a regulated environment, the utility can potentially reduce cost of reserve provision by using these extremely fast responding resources. How can this happen? The greater responsiveness and accuracy may result in a reduction of the total capacity that is held in reserve freeing up these resources to be used more economically elsewhere. If EES resources are not called upon to inject energy, they have the opportunity to sell stored energy as other services

Organizing the Investment Decision

VIU Business Model

In many utility jurisdictions the "next best" alternative to EES for electric supply capacity is considered to be a combustion turbine. As such a combustion turbine could be the "benchmark" or "base case" alternative and its LCOE would be evaluated using the LCOE calculator. EES and other alternatives would then be compared on the same LCOE basis.

Market Resource Allocation Model

The investment decision is governed by the excess of annual net revenue from sales of capacity for reserve and/or sale of electricity into energy markets over the annual levelized cost of energy of the combustion turbine on the one hand and the EES system on the other.

3.9 Stacking Benefits

In order to maximize the value or revenue stream from an EES system, it is common to identify multiple potential Functional Uses. In theory, this will increase the value of the system. This practice presents two challenges. First, from a valuation perspective it becomes more difficult to assign a value to the services provided and brings in the possibility of "double-counting" benefits, which will result in an inflated valuation. Second, from an operational perspective it is a challenge to identify control algorithms that provide the multiple Functional Uses while maximizing the potential value of the system. The most straightforward approach to evaluating a scenario with stacked benefits is to rely on a state-of-charge model of the EES system to guarantee that the Functional Uses are served without violating the physical characteristics of the system.

An EES model that incorporates storage efficiency and conversion efficiency is given by

$$S_t = S_{t-1} + \gamma_c q_t^c - q_t^d - \gamma_s S_{t-1}, \quad \text{(MWh)} \tag{3.5}$$

where

S_t	Energy stored at the end of time period t
S_{t-1}	Energy stored at the end of time period $t-1$
γ_c	Conversion efficiency (percent)
q_t^c	Quantity of energy pulled from the grid (charge) during time period t (MWh)
q_t^d	Quantity of energy provided to the grid (discharge) during time period t (MWh)
γ_s	Storage efficiency (percent)

Additional parameters associated with the model are the length of the time period, the maximum charge/discharge quantities and the maximum storage capacity of the system. These quantities are defined as:

Δt	time period (for example, hours)
$\bar{q}^D$	maximum quanitity that can be sold/discharged in a single period (MWh)
$\bar{q}^R$	maximum quantity that can be bought/recharged in a single period (MWh)
$\bar{S}$	maximum storage capacity (MWh)

In a stacked benefit scenario, it is helpful to keep track of the amount of energy charged or discharged during each time period for each activity. This insures that the constraints of the device are met at all times and the revenue can be allocated based on the service provided. It also makes it harder to double count benefits because each benefit is a function of the energy transaction. For a scenario with N potential benefits, the charge and discharge quantities are given by

$$q_t^c = \sum_{i=1}^{N} q_t^c(i), \quad \text{(MWh)} \tag{3.6}$$

$$q_t^d = \sum_{i=1}^{N} q_t^d(i), \quad \text{(MWh)} \tag{3.7}$$

where $q_t^c(i)$ is the charging energy associated with the i^{th} activity and $q_t^d(i)$ is the discharging energy associated with the i^{th} activity

The revenue at each time step is given by

$$R_t = \sum_{i=1}^{N} q^d(i)_t(P_t^d(i) - C_t^d(i)) - \sum_{i=1}^{N} q_t^c(i)(P_t^c(i) + C_t^c(i)) \tag{3.8}$$

where

$P_t^d(i)$	Price received for discharging at time period t for the i^{th} activity (\$/MWh)
$C_t^d(i)$	Cost for discharging at time period t for the i^{th} activity (\$/MWh)
P_t^c	Price paid for charging at time period t for the i^{th} activity (\$/MWh)
C_t^c	Cost for charging at time period t for the i^{th} activity (\$/MWh)

The present value of the energy storage system operating for T time increments can be written as

$$\text{Present Value} = \sum_{t=1}^{T} \left(\sum_{i=1}^{N} q^d(i)_t(P_t^d(i) - C_t^d(i)) - \sum_{i=1}^{N} q_t^c(i)(P_t^c(i) + C_t^c(i)) \right) e^{-rt} \tag{3.9}$$

Using this relationship, it is possible to calculate the present value of a system using either historical or estimated price data under a wide range of scenarios with stacked benefits. The charge/discharge quantities can be derived to maximize revenue (e.g. a linear programming optimization problem) or are generated by a candidate control algorithm. In a market area one can utilize historical price data. In a vertically integrated utility, the most difficult task is estimating the appropriate prices and costs to use in the model. An example of estimating the maximum potential revenue from participating in arbitrage and frequency regulation is described in [15].

The last chapter provides a summary of the information presented in this report.

Chapter 4

Summary and Conclusions

As the amount of renewable generation increases, the inherent variability of wind and photovoltaic systems must be addressed in order to ensure the continued safe and reliable operation of the nation's electricity grid. Grid-scale energy storage systems are uniquely suited to address the variability of renewable generation and to provide other valuable grid services. The goal of this report was to quantify the technical performance required to provide different grid benefits and to specify the proper techniques for estimating the value of grid-scale energy storage systems.

Evaluating the technical performance of an energy storage system with respect to a well-defined set of requirements is relatively straightforward. Unfortunately, in the electric power industry standards vary by region, and in some cases are vague or nonexistent. A good example is the performance required to participate in the frequency regulation market. FERC order 755 states that providers must be "paid for performance". Even though this is a step in the right direction, each ISO is developing their own approach for meeting FERC order 755. This regional approach results in a system where the "value" of an energy storage system is highly location dependent. The same holds true for voltage support services. In addition to being able to provide the proper reactive power levels, the device must also be located in a suitable location in the grid. These examples highlight some of the difficulties in evaluating the technical and economic performance of an energy storage system. Both depend not only on the characteristics of the device, but also on the location in the grid. The approach taken in this report was conservative. Technical performance specifications were outlined that if met, then assuredly the device can claim it serves that issue. But, if the device does not meet the requirements, it could still help in the given issue depending on the extent to which the requirements are not met.

The economic section outlined a four-step sequential analysis process for evaluating energy storage systems:

Step 1 Identify required services and solution concepts.

Step 2 Identify feasible Functional Uses.

Step 3 Identify and assess grid impacts including incidental benefits.

Step 4 Develop energy storage business cases.

A functional use is a technically feasible combination of grid services. This report defined ten Functional Uses for an electricity energy storage system. Several different investment criteria were then identified and guidelines were put forth for different investment decisions. The process and key features were sketched out for each of the ten Functional Uses. The report concludes with a brief discussion on the valuation of stacked benefits via a state-of-charge model for the EES. One of the benefits of this approach is that by assigning quantities of energy to each activity, the constraints of the system are guaranteed to be met and it is more difficult to "double count" benefits, which would result in an inflated valuation.

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Appendix A - Dynamic Response

Step Response

A step response of a system is the response to an instantaneous step at the input. A normalized response is shown in the below figure. The input step has an amplitude of one. Key variables are:

- T_r = Rise Time = Time to rise within 90% of the final value.
- T_p = Peak Time = Time to reach the peak value of the response.
- T_s = Settling Time = Time to settle within 5% of final value.
- $\%OS$ = Percent Overshoot = $\left(\dfrac{Peak\ Value - Final\ Value}{Final\ Value}\right) 100$

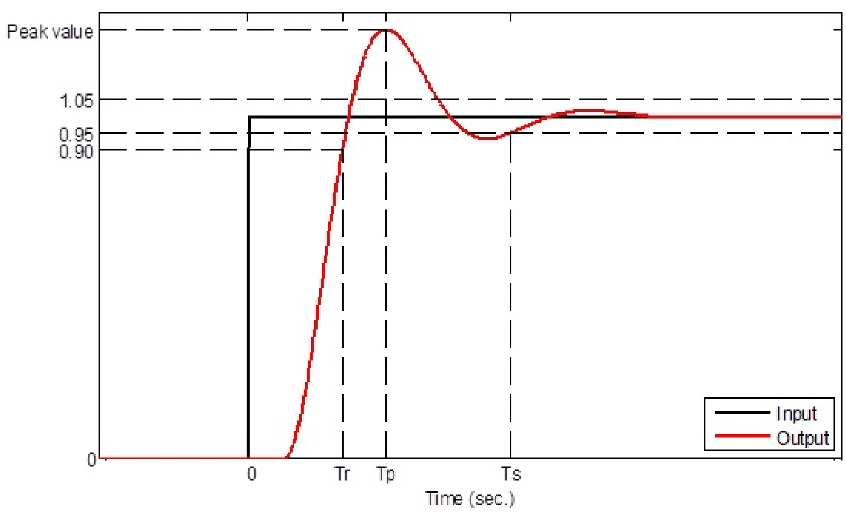

Figure A.1: Key parameters of a normalized step response.

Dynamic Availability

The below figure shows a "Dynamic Availability" test. An input consisting of a series of three 50% duty cycle pulse trains separated by constant values is applied to the system. The output is then recorded with time-stamps corresponding to the input. Parameters include:

- $Amax$ = the max amplitude of the input.
- $Amin$ = the min amplitude of the input.
- $Amid$ = the starting and ending value of the input.
- $Tc1$ thru $Tc4$ = length of time to hold input constant.
- $Tp1$ thru $Tp3$ = length of time for pulsing input.
- f_p =frequency of pulsing signal (Hz).

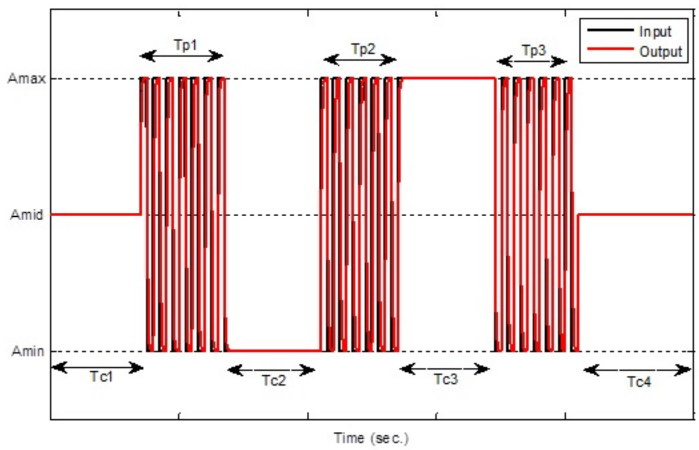

Figure A.2: Dynamic availability test.

Appendix B - Incremental Benefit Cost Analysis and Net Present Value Analysis

Many engineering economics texts recommend an incremental benefit-cost analysis for three or more mutually exclusive alternatives [3]. Although most mention that this is consistent with a present worth analysis, this is often overlooked. In this appendix we illustrate the equivalence between incremental benefit-cost analysis and the maximization of net present value (NPV).

The steps for performing an incremental benefit-cost analysis are outlined below [3].

1. Identify all relevant alternatives.
2. Calculate the B/C ratio of each alternative.
3. Rank order the projects from smallest to largest cost.
4. Identify the increment under consideration. The first increment is always the lowest cost option compared to the do-nothing alternative.
5. Calculate the B/C ratio for the incremental cash flows.
6. Use the incremental B/C ratio to select the most desirable option.
7. Iterate to Step 4 until all increments have been considered.
8. Select the project with the last justified increment.

In order to show that this approach is equivalent to maximizing the NPV, first consider cash flow A and B. The NPV of each cash flow is defined as

$$NPV(A) = \sum_{i=0}^{N} \frac{A_i}{(1+r)^i} \tag{B.1}$$

$$NPV(B) = \sum_{i=0}^{N} \frac{B_i}{(1+r)^i} \tag{B.2}$$

The incremental cash flow is defined as

$$\Delta\text{Cashflow} = \sum_{i=0}^{N} \frac{A_i - B_i}{(1+r)^i} = \sum_{i=0}^{N} \frac{A_i}{(1+r)^i} - \sum_{i=0}^{N} \frac{B_i}{(1+r)^i} = NPV(A) - NPV(B) \tag{B.3}$$

Therefore, the incremental benefit or cost is simply the difference in the net present value of the benefits or costs.

Following the incremental benefit-cost analysis steps, the different projects are rank ordered from smallest to largest cost.

$$\text{Ranked projects} = \left(\frac{B_1}{C_1},\ \frac{B_2}{C_2},\ \frac{B_3}{C_3},\ \ldots\ ,\frac{B_N}{C_N}\right),\ \ \text{where } C_i \geq C_{i-1},\ \ i = 2,\ 3,\ \ldots\ ,N \tag{B.4}$$

When considering the incremental B/C ratio in step 6, it is always a pairwise comparison between two options (renumbered a and b).

$$\frac{\Delta B}{\Delta C} = \frac{B_b - B_a}{C_b - C_a} \tag{B.5}$$

if the ratio is greater than 1.0, project b is selected and project a is discarded. Likewise, if the ratio is less than or equal to 1.0, project a is selected and project b is discarded. If the incremental B/C ratio is greater than 1.0, we have the following

$$\frac{B_b - B_a}{C_b - C_a} > 1.0 \tag{B.6}$$

$$B_b - B_a > C_b - C_a \tag{B.7}$$

$$B_b - C_b > B_a - C_a \tag{B.8}$$

$$NPV(b) > NPV(a) \tag{B.9}$$

Similarly, for the case of an incremental B/C ratio less than or equal to 1.0,

$$\frac{B_b - B_a}{C_b - C_a} \leq 1.0 \tag{B.10}$$

$$B_b - B_a \leq C_b - C_a \tag{B.11}$$

$$B_b - C_b \leq B_a - C_a \tag{B.12}$$

$$NPV(b) \leq NPV(a) \tag{B.13}$$

Therefore, each step of the incremental benefit-cost analysis is equivalent to selecting the project with the largest net present value. Applying this to the rank order pairs results in selecting the project with the highest net present value. This shows the equivalence between incremental benefit-cost analysis and selecting the project with the highest NPV.

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