CALIFORNIA RENEWABLES PORTFOLIO STANDARD RENEWABLE GENERATION INTEGRATION ANALYSIS

PHASE I
ANALYSIS OF INTEGRATION COSTS FOR EXISTING GENERATION

PREPARED FOR

The California Energy Commission
The California Public Utilities Commission

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Abbreviations

ACE	Area Control Error
ADS	Automated Dispatch System
AGC	Automatic Generation Control
CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CPS	Control Performance Standard
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
Hz	Hertz
IOU	Investor Owned Utility
ISO	Independent System Operator
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MW	Megawatt (unit of power)
MWh	Megawatt-hour (unit of energy)
NERC	North American Electric Reliability Council
NREL	National Renewable Energy Laboratory
ORNL	Oak Ridge National Laboratory
RPS	Renewables Portfolio Standard
RTO	Regional Transmission Organization
$/MW-hr	cost per Megawatt for one hour

Nomenclature

ACE	*area control error*
ß	*control area frequency bias*
C_i	*capacity available in hour i*
ΔC_i	*effective capacity of analyzed resource at hour i*
ΔC_p	*effective capacity of analyzed resource at peak hour of year*
$COST_{lf}$	*cost of supplemental energy*
$COST_R$	*cost of regulation*
F_A	*actual system frequency*
F_S	*scheduled system frequency*
G	*total actual system generation*
g_i	*generation of analyzed resource*
g_i	*generation of analyzed resource at hour I*
$\overline{g_{i,15}}$	*fifteen minute rolling average of generation of analyzed resource*
g_{i,s_1}	*hour-ahead generation forecast/schedule*
g_{i,s_2}	*short term generation forecast*
I_{ME}	*meter error*
i	*generic indicator of analyzed resource*
L	*total actual system load*
$\overline{L_{15}}$	*fifteen minute rolling average of system load*
L_i	*hourly system load*
L_{s_1}	*hour-ahead load forecast/schedule*
L_{s_2}	*short term load forecast/real-time load schedule*
$LOLE$	*loss of load probability*
$LOLE'$	*LOLE with resource of interest added to system*
lf_i	*supplemental energy requirement of analyzed resource*
lf_L	*supplemental energy requirement of load*
N	*number of hours in the year*
NI_A	*actual net tie flows of control area*

NI_S	*scheduled net tie flows of control area*
P	*probability function*
R_{actual}	*actual amounts of purchased/self provided regulation*
R_i	*regulation requirement of analyzed resource*
$\hat{R}_i$	*allocated regulation share of analyzed resource*
$RATE_{lf}$	*actual market rate of supplemental energy*
$RATE_R$	*actual market rate of regulation*
r_i	*raw regulation component of analyzed resource*
r_L	*regulation component of total system load*
Δr_i	*regulation of system load less the resource of interest*
σ	*standard deviation*
σ_i	*standard deviation of regulation component of analyzed resource*
σ_T	*standard deviation of regulation component of total system load*
σ_{T-i}	*standard deviation of regulation component of total system load less the analyzed resource*
T	*total*
t	*time*
x	*dummy variable*

Also see nomenclature locally defined within each section.

Executive Summary

As mandated by California state legislation, renewable generation projects will compete to fulfill the state's Renewables Portfolio Standard (RPS) through a "least-cost, best-fit" bid selection process. This process must consider indirect costs, which can be broken down into transmission investments and integration costs.

As requested by the California Energy Commission on behalf of the California Public Utilities Commission, a multi-phase study is being conducted to define and quantify integration costs. This document proposes analysis methodologies for the first phase of the effort, which will quantify the integration costs of California's existing renewable generators. Although the analysis methodologies presented are for the first phase of the study, they are a critical foundation for the final methodologies that will be developed in the subsequent phases of the study and ultimately incorporated into the RPS bid selection process. The methodologies are presented for public comment and discussion. The results of that discussion will be considered in the process of the integration cost study.

1 Introduction

1.1 Historical Background

California's recently enacted *Renewables Portfolio Standard* (RPS, Senate Bill 1078) requires the state's *investor-owned utilities* (IOUs) to increase the renewable portion of their energy mix with a goal of 20% renewable energy generation by 2017. Renewable generation projects will compete with each other to supply the IOUs, with the *California Public Utilities Commission* (CPUC) establishing a process to select the "least-cost, best-fit" projects. As stated in the RPS (399.14.a.2.B), by 30 June 2003, the CPUC must:

> *...adopt a process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources.*

1.2 Defining Integration Costs

The *integration costs* are the "ongoing utility expenses from integrating and operating eligible renewable energy resources." In the enabling legislation, the costs of transmission investments are explicitly differentiated from the integration costs. The *California Energy Commission* (CEC), in cooperation with the CPUC, organized a team to study integration costs. The goal of this study is to estimate the integration costs of various generators, so that those costs can be incorporated into the least-cost analysis. As shown in Figure 1.1, the total cost will be the sum of the direct and indirect costs. Integration costs are a subset of the indirect costs.

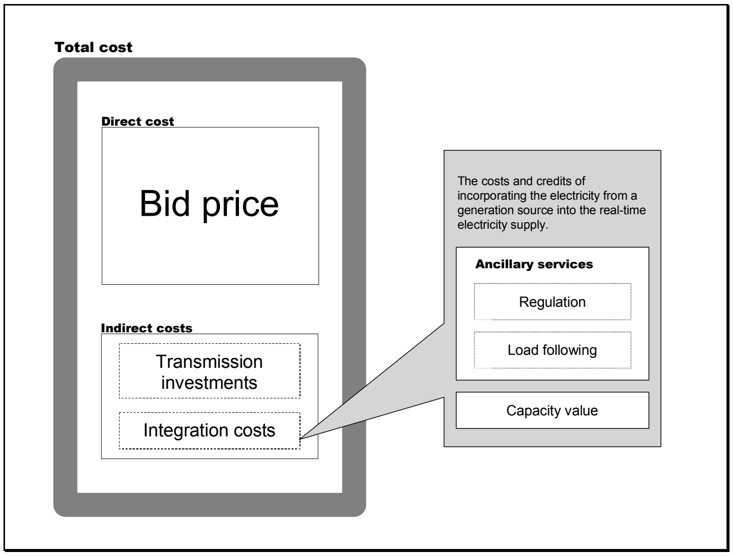


Figure 1.1 How Integration Costs Fit in the Least-Cost Best-Fit Analysis

1.2.1 CONTROL PERFORMANCE STANDARDS

The electrical power system operated by the *California Independent System Operator* (CAISO) is called its *control-area*. Power plants, or *generators*, located throughout the state are managed in real-time to meet the demands, or *loads,* of electricity customers. Because electricity is a real-time product in which loads and generation fluctuate and cannot be perfectly predicted, control-area operators, or *dispatchers*, must constantly adjust generation to meet load. CAISO manages electrical *energy*, generating *capacity*, and other *ancillary services* that are used to maintain control and reliability of the California utility grid.

The CAISO must manage its generators to compensate for the real-time variations between actual generation and actual load in the electric system. The *North American Electric Reliability Council* (NERC) recognizes the *area control error* (ACE) as a primary metric used to assess the performance of the control operator. Each control area seeks to minimize its effects on the neighboring control areas to which it maintains an *interconnection*. Errors incurred because of generation, load or schedule variations or because of jointly owned units, contracts for regulation service, or the use of dynamic schedules must be kept within the control area and not passed to the interconnection. The equation for ACE (NERC 2002) is:

$$ACE = (NI_A - NI_S) - 10\beta\,(F_A - F_S) - I_{ME} \qquad [1.1]$$

In this equation, NI_A accounts for all actual meter points that define the boundary of the control area and is the algebraic sum of flows on all tie lines. Likewise, NI_S accounts for all scheduled tie flows of the control area. The combination of the two ($NI_A - NI_S$) represents the ACE associated with meeting schedules and if used by itself for control would be referred to as flat tie line regulation.

The second part of the equation, $10\beta\,(F_A - F_S)$, is a function of frequency. The 10β represents a control area's frequency bias (β's sign is negative) where β is the actual frequency bias setting (MW/0.1 Hz) used by the control area and 10 converts the frequency setting to MW/Hz. F_A is the actual frequency and F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections. I_{ME} is the meter error recognized as being the difference between the integrated hourly average of the net tie line instantaneous interchange MW (NI_A) and the hourly net interchange demand measurement (MWh). This term should normally be very small or zero.

The North American Electric Reliability Council (NERC 2002) *Control Performance Standards* (CPS) 1 and 2 set statistical limits on the allowable differences between one-minute averages of the control area's difference between aggregated generation and interchange schedules relative to load (i.e., ACE). CPS1 measures the relationship between the control area's ACE and its interconnection frequency on a one-minute average basis. CPS1 values are recorded every minute, but the metric is evaluated and reported annually. NERC sets minimum CPS1 requirements that each control area must exceed each year. CPS2 is a monthly performance standard that sets control-area-specific limits on the maximum average ACE for every 10-minute period.

Neither CPS1 nor CPS2 require that the ISO maintain a zero value for ACE. Small imbalances are generally permissible, as are occasional large imbalances. Both CPS1 and CPS2 are statistical measures of imbalance, the first a yearly measure and the second a monthly measure. Also both CPS standards measure the aggregate performance of the control area, not the behavior of individual loads or generators. Control areas are permitted to exceed the CPS2 limit no more that 10% of the time. This means that a control area can average no more than 14.4 CPS2 violations per day during any month.

1.2.2 ANCILLARY SERVICES

Ancillary services are the corrective actions needed to integrate electricity from generation sources into a larger, real-time electricity supply. In this state, the CAISO purchases ancillary services to continually balance the imperfectly predicted, constantly changing load demand with the electricity supply from generators which do not perfectly match their prescribed output. All loads and generators, both conventional and renewable, require ancillary services at some time. These services exist without the presence or absence of renewable generation resources.

This study seeks to quantify the costs of ancillary services for various types of existing generation. Some studies have shown that renewable generators, because of their intermittent nature, require more ancillary services than others. Ancillary services are being considered in this study specifically so that we may quantify the difference in costs associated with various types of generation technologies currently operating throughout California. *Regulation* and *load following (supplemental energy)* are the two key ancillary services required to perform this function. (Kirby and Hirst, 2000)

Terminology associated with ancillary services has not been standardized across the utility industry and there has been confusion of terms. It is important to distinguish between the *impacts* imposed upon the power system and the *resources or services* the CAISO utilizes to compensate for these impacts. The *impacts* are imposed upon the power network by loads, uncontrolled generators, and transactions. The *resources or services* that compensate for these impacts are supplied by generators responding to *automatic generation control* (AGC) or the *automated dispatch system* (ADS).

In 1996 the *Federal Energy Regulatory Commission* (FERC), defined six ancillary services in its Order 888. This order did not discuss load following. Perhaps because of this omission, most utilities and *independent system operators* (ISOs) do not include load following in their tariffs. The absence of this service required some ISOs to acquire much more regulation than they otherwise would need. Perhaps because of these problems, FERC (1999), in its notice on *regional transmission organizations* (RTOs), proposed to require that RTOs operate real-time balancing markets. The responsive resources for these *supplemental energy* markets are generators that can change output every ten minutes as needed to follow load.

The CAISO obtains responsive resources to achieve the required real-time balancing of generation and load from the hourly regulation markets and the short-term energy markets. The alignment between the impacts that the CAISO must meet and the services it procures to meet those impacts is not perfect. Resources procured through the regulation markets, for example, could be used to provide load following, accommodate energy imbalance, or even supply base energy if there were no other alternatives. Load following itself is not a service which the CAISO procures directly. The CAISO meets its load following needs through short-term energy transactions, including both AGC generators and the supplemental energy market.

1.2.3 CAPACITY CREDIT

CAISO must constantly manage the state's supply of power and energy to control the electrical grid. Generating capacity (power) is critical to assure the reliability of the electric system. A generator's ability to deliver power when needed provides capacity value to the system that is separate and distinct from the energy it generates. Additional generation capacity is a valuable asset because it increases reliability during peak demand periods. Generation from renewable energy sources is often intermittent in nature, which complicates the analysis of the capacity they provide the grid. As used here, the term *capacity credit* will define the capacity a generator adds to the system, as measured by the increased load that can be supported at a given level of system reliability. The capacity credit of a given generator is a function of the reliability of that generator and system demand. No generator is perfectly reliable, so every type of generator has a capacity credit which is less than 100% of its maximum rated power. Some generators, because of decreased reliability or intermittent resource availability, will have a lower capacity credit than others.

Renewable energy sources have operational characteristics that are different from conventional power generation facilities. One of the key differences is the intermittent production output of some renewable energy sources. The inability of the CAISO to control intermittent generation is a characteristic that has important ramifications for the integration of renewable generation sources into the network. Utilities are often reluctant to assign a capacity credit to renewable generators, largely because of the intermittent nature of the resource and the perceived difficulties in accurately forecasting power output. If an intermittent generator is unable to claim an operational capacity credit, then other generating resources must be committed in an amount equal to the operating level for the intermittent generator for a specific time period. An intermittent generator will have more value if it can replace conventional committed capacity, at least for some portion of the year.

An intermittent generation resource that can be counted on for capacity will maximize its contribution to system reliability. An accurate forecast allows the utility to count intermittent generation capacity and reduce costs without violating reliability constraints. The simplest benefit of an accurate intermittent generator forecast is that generation (capacity and energy) can be planned for and used to avoid the use of fuel to produce electricity. Renewable generators act as fuel saving facilities and benefits are increased if the output of renewable generators is used to offset the most expensive fuel in the mix.

This simplified point of view is complicated by constraints imposed by integrating the intermittent resource with the rest of the electricity supply system.

Intermittent generators have capacity value if they increase the reliability of the system, even if the forecasts are not accurate. The best method for determining capacity value of intermittent generators is to calculate their *effective load carrying capability* (ELCC). This requires a reliability model that can calculate *loss of load probability* (LOLP), loss of load expectation (LOLE), or *expected unserved energy* (EUE). ELCC is a way to measure a power plant's capacity contributions based on its influence on overall system reliability. Using a measure such as ELCC, all power plants with a non-zero forced outage rate have an ELCC that is less than rated capacity (barring unusual plants with artificially low-rated capacity with respect to actual achieved capacity). The ELCC measure is often used as a way to compare alternative power plants, and can be easily applied to intermittent generators as well. A power plant's ELCC is typically calculated with an electric system reliability model or by a production-cost model.

1.3 Project Goals

The overall project goal is to develop a valuation methodology for integration costs that can be applied to the selection process of RPS eligible generation projects. Because project selection is a public process for California, the final methodology will:

- use input data and analysis tools available in the public domain
- be fair, transparent, and coherent
- provide cost estimates that are representative of California
- be clearly defined, provide repeatable results, and be analyst independent

1.4 Project Organization

The study is divided into three sequential phases, with each phase lasting approximately six months, as shown in Figure 1.2.

1.4.1 PHASE I: ANALYSIS OF INTEGRATION COSTS FOR EXISTING GENERATION

The initial efforts in Phase I focused on documenting the methodologies to be used for evaluating the integration costs of California's existing renewable and non-renewable generation sources. Goals for development and documentation of the analysis methodologies were:

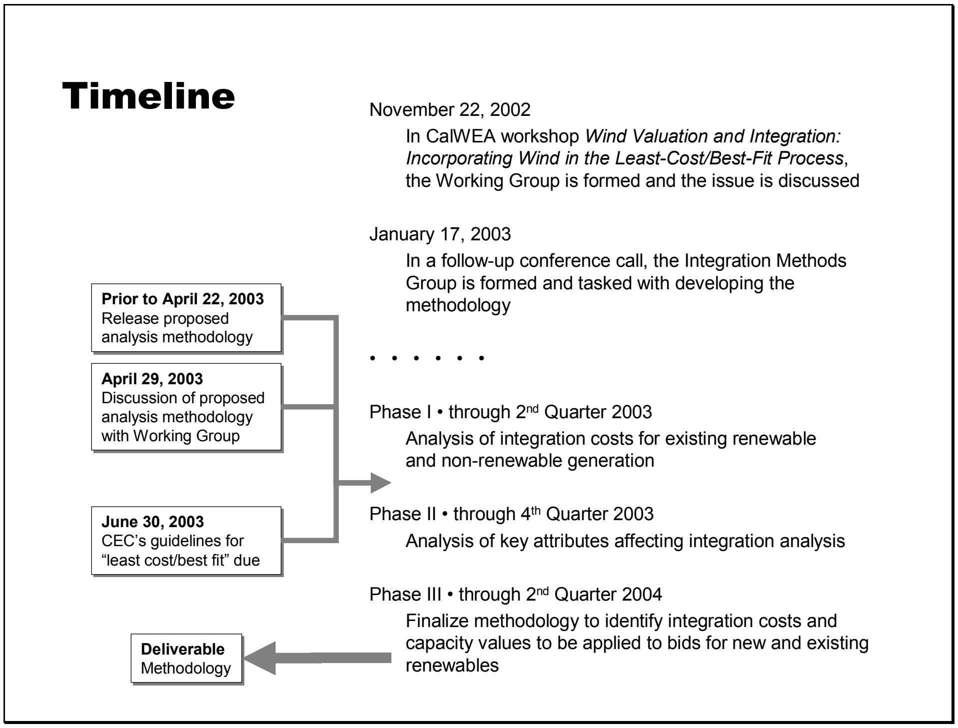
- The methodology should apply equally and fairly to all renewable generators eligible under the Renewables Portfolio Standard.

- The methodology should clearly define the analysis approach including the data requirements and the underlying assumptions.

- The documentation should provide a step-by-step process methodology to show how the data would be processed for each generator type.

- Each methodology should be used to analyze the same sample data file, so the results can be compared and contrasted.

The existing generation analysis will provide the foundation for proceeding to the Phase II study. Completion of the Phase I effort is expected in 30 June 2003 assuming data is available by no later than 1 May 2003. The data necessary for this analysis is held by CAISO, but has not yet been released pending resolution of confidentiality issues.



Timeline

November 22, 2002
In CalWEA workshop *Wind Valuation and Integration: Incorporating Wind in the Least-Cost/Best-Fit Process*, the Working Group is formed and the issue is discussed

January 17, 2003
In a follow-up conference call, the Integration Methods Group is formed and tasked with developing the methodology

. . . . . .

Phase I • through 2nd Quarter 2003
Analysis of integration costs for existing renewable and non-renewable generation

Phase II • through 4th Quarter 2003
Analysis of key attributes affecting integration analysis

Phase III • through 2nd Quarter 2004
Finalize methodology to identify integration costs and capacity values to be applied to bids for new and existing renewables

Prior to April 22, 2003
Release proposed analysis methodology

April 29, 2003
Discussion of proposed analysis methodology with Working Group

June 30, 2003
CEC's guidelines for "least cost/best fit" due

Deliverable
Methodology

Figure 1.2 Integration Study Timeline

1.4.2 PHASE II: ANALYSIS OF KEY ATTRIBUTES AFFECTING INTEGRATION ANALYSIS

In Phase II, the key attributes of renewable generators that affect integration cost will be identified and their contributions to integration cost will be analyzed using the methodology developed in Phase I. Recognizing the diversity of renewable energy resources, public input will be solicited to aid in the identification of the attributes. These attributes may include:

- various generator technologies
- location and climate
- level of penetration

Completion of Phase II is expected in December 2003.

1.4.3 PHASE III: FINALIZE METHODOLOGY FOR INTEGRATION COSTS FOR APPLICATION TO RPS BID SELECTION

In the third and final phase, the methodology developed in Phase I will be modified so that the attributes identified in Phase II are correctly modeled for the analysis of new renewable energy projects. The final methodology will be released openly to the public.

Completion of Phase III is expected in June 2004.

1.5 Document Scope

This document was prepared toward the end of the first half of Phase I. It describes proposed methodologies for analysis of the integration costs of California's existing generation. The methodologies are presented for public review, comment, and discussion. After the incorporating public input, the methodologies will be applied toward the completion of Phase I and the subsequent phases of this integration study.

Two alternative methodologies for calculating the ancillary services costs were reviewed by the group. One ancillary services methodology, developed by Brendan Kirby et. al. at *Oak Ridge National Laboratory* (ORNL), is presented in Section 2. Variations of this methodology have been previously applied by a number of investigators to calculate integration costs and ancillary service impacts of intermittent generators and loads in several other control areas. The analysis approach was adjusted to reflect the needs of the RPS Integration Study and to address the specifics of the CAISO system.

An alternative ancillary services methodology was developed by Yuri Makarov at the CAISO during the course of the Phase I study and is presented in Section 3. Both ancillary services analysis methods use the same input data and considerable effort was spent to use common nomenclature, so they can be compared against one another. It is hoped that both methods will be used to evaluate the integration costs in the Phase I effort using the same data inputs, so any differences in results can be attributed to the specific analysis approach.

This document is currently in draft form. The analysis methodologies presented may change to incorporate additional information. The final methods will be documented at the completion of the effort and presented to the CEC and the CPUC for review.

2 Ancillary Services Cost Analysis: Method 1

BRENDAN KIRBY ET AL, OAK RIDGE NATIONAL LABORATORY

The methodology presented in this section was primarily developed by Brendan Kirby of ORNL.

2.1 Decomposition of Control Area Loads

The first methodology has been applied to a variety of other control areas to quantify the ancillary service impacts of loads and intermittent resources. It determines the regulation and load following impacts to the control area. These impacts are the result of fluctuations in aggregate load and/or uncontrolled generation that must be compensated. Once the requirements are quantified, the method then determines the costs incurred in terms of greater amounts of purchased regulating capacity and greater use of the short-term energy markets.

Loads within the control area can be decomposed into three elements (Figure 2.1). The first element is the initial load (base) of the scheduling period, 80 MW over the one hour period shown in this case. The second element is the trend (ramp) during the hour and from hour to hour (the morning pickup in this case); here that element increases from 0 MW at 7 a.m. to 18 MW at 8 a.m. The third element is the rapid fluctuations in load around the underlying trend; as shown here the fluctuations range over ±1 MW. Combined, the three elements yield a load that ranges from 79 to 98 MW during the hour.

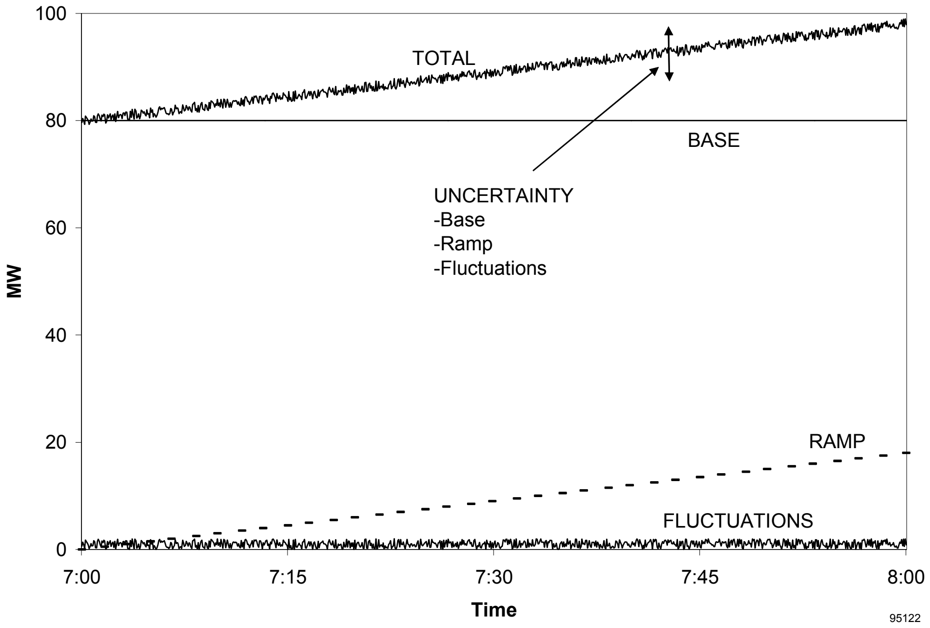


Figure 2.1 Components of a Hypothetical Load on a Weekday Morning

The system responses to the second and third components are called load following and regulation. These two services ensure that, under normal operating conditions, a control area is able to balance generation to load. The two services are briefly defined [see also FERC (1996), Hirst and Kirby (1998), and NERC (2002)]:

- *Regulation* is the use of online generating units that are equipped with automatic generation control (AGC) and that can change output quickly (MW/minute) to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. In so doing, regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. This service can be provided by any appropriately equipped generator that is connected to the grid and electrically close enough to the local control area that physical and economic transmission limitations do not prevent the importation of this power.

- *Load following* is the use of online generation equipment to track the intra- and inter-hour changes in customer loads. Load following differs from regulation in three important respects. First, it occurs over longer time intervals than does regulation, 10 minutes or more rather than minute to minute. Second, the load-following patterns of individual customers can be highly correlated with each other, whereas the regulation patterns are largely uncorrelated. Third, load-following changes are often predictable (e.g., because of the weather dependence of many loads) and have similar day-to-day patterns.

Assessing the individual customer, or renewable generator, contribution to the overall regulation requirement necessarily involves evaluating generation performance. A control area is not expected to perfectly match generation and load instantaneously. Rather, generation matches load with some time lag, and, therefore, generation matches load only approximately. Although the AGC systems at most utility control centers send raise and lower pulses to individual generators as frequently as every two or four seconds, generators do not follow such short-term load fluctuations. Our prior work (Hirst and Kirby 1996) suggests that generation follows load at the one- to two-minute interval.

There is no hard-and-fast rule to define the temporal boundary between regulation and load following. If the time chosen for the split is too short (e.g., five minutes), too much of the fluctuations will appear as load following and not enough as regulation. If the boundary is too long (e.g., 60 minutes), too much of the fluctuations will show up as regulation and not enough as load following. But in each case, the total is unchanged and is captured by one or the other of these two services.

2.2 Regulation Analysis

2.2.1 CALCULATION OF THE REGULATION COMPONENT

We propose to analyze the regulation requirements of the CAISO system and to determine the impact of individual uncontrolled generators on the total regulation requirement utilizing a method developed by Oak Ridge National Laboratory (ORNL) (Kirby and Hirst 2000). This method has been used to analyze control area performance, individual loads, non-conforming loads, non-AGC generators, and wind plants for a number of utilities including: American Electric Power (AEP), Central & South West (CSW), NIPSCO, Bonneville Power Authority (BPA), Commonwealth Edison (ComEd), Pennsylvania-New Jersey-Maryland Interconnection (PJM), Alberta, New Brunswick, and Ontario Hydropower. Electrotek used the method in their analysis for Xcel (Brooks et al 2002), Great Rivers, and ERCOT.

Specifically, we will utilize 1-minute average energy data and a 15-minute rolling average to separate regulation from load following. We will calculate the rolling average for each 1-minute interval as the mean value of the seven earlier values of the variable, the current value, and the subsequent seven values:

$$Load\ Following_t = Load_{estimated\text{-}t} = mean\ (L_{t-7}\ ,\ L_{t-6}\ ,\ \ldots\ ,\ L_t\ ,\ L_{t+1}\ ,\ \ldots\ ,\ L_{t+7}) \qquad [2.1]$$

$$Regulation_t = Load_t - Load_{estimated\text{-}t} \qquad [2.2]$$

This method is somewhat arbitrary and imperfect (Kirby and Hirst 2000). It is arbitrary in that the time-averaging period (15 minutes in this project) and the temporal aggregation of raw data (1 minute) cannot be predetermined. In principle, the control-area characteristics (dynamics of generation and load and the short-term energy market interval) should determine these two factors (Hirst and Kirby 2000). For purposes of this study the 15-minute rolling average was selected because it provides good temporal segregation and captures the characteristics of California's supplemental energy market.

We will calculate the standard deviation of the 1 minute regulation values for total system load hourly as the metric for regulation performance. A utility typically carries about three standard deviations of regulating reserves to assure adequate CPS performance.

2.2.2 SHORT TERM FORECAST VERSUS ROLLING AVERAGE

In practice, system operators cannot know future values of load. They generally produce short-term forecasts of these values to aid in generation-dispatch decisions. There are two problems with using short-term forecasts to separate regulation and load following. First, while aggregate load forecasts are typically well developed, short-term forecast methodologies for non-dispatchable conventional and renewable generators are not. The CAISO is currently developing an improved forecasting tool for wind, for example. Second, even when they are being used for operations the short-term forecast results for individual generators or loads are typically not saved. Finally, the rolling average has proven to be a reasonable analytical substitute in studying other control areas. The rolling average, like the system operator, is constantly moving the regulating units back to the center of their operating range. When consistent, robust short-term forecasts are available and verified for all of the renewable generation technologies, this analysis can be repeated without needing to use the rolling average.

The use of the rolling average rather than the short term forecasts can impact the allocation of variability between the regulation and load following services slightly. Significantly, the method assures that total variability is captured in one or the other service and that there is no double counting.

2.2.3 INDIVIDUAL RENEWABLE GENERATOR METRICS

Once we determine the hourly regulation requirements for the entire system we will calculate individual contributions to that total requirement. Regulation aggregation is nonlinear, there are strong aggregation benefits. It takes much less regulation effort to compensate for the total aggregation than it would take if each load or generator compensated for its regulation impact individually. While this is a great benefit it also means that there is no single "correct" method for allocating the reduced total regulation requirement among the individuals. An allocation method should:

- Recognize positive and negative correlations
- Be independent of sub-aggregations
- Be independent of the order in which loads or resources are added to the system
- Allow dis-aggregation of as many or few components as desired

The method presented here, and described more fully in the appendix, meets these criteria. It was developed by ORNL to analyze the impacts of nonconforming loads on power system regulation. It works equally well when applied to non-dispatchable or uncontrolled generators.

With the ORNL method it is not necessary to know every individual's contribution to the overall requirement. Specific individuals' contributions can be calculated based upon the total requirement and the individuals' performance. Because regulation is the short, minute-to-minute fluctuations in load, the regulation component of each individual is often largely uncorrelated with those of other individuals. If each individual's fluctuations (represented by the standard deviation (σ_i) is completely independent of the remainder of the system, the total regulation requirement (σ_T) would equal:

$$\sigma_T = \sqrt{\sum \sigma_i^2} \qquad [2.3]$$

where *i* refers to an individual and *T* is the system total.

For the case of uncorrelated contributions, the share of regulation assigned to each individual is:

$$Share_{\mathrm{i}} = \left(\frac{\sigma_i}{\sigma_T}\right)^2 \qquad [2.4]$$

The more general allocation method, developed by ORNL (Kirby and Hirst 2000) and presented in Equation 2.5 accommodates any degree of correlation and any number of individuals. This allocation method is more complex but no more data-intensive than the previous method. This method yields results that are independent of any sub-aggregations. In other words, the assignment of regulation to generator (or load) g_i is not depend on whether g_i is billed for regulation independently of other non-AGC generators (or loads) or as part of a group. In addition, the allocation method rewards (pays) generators (or loads) that reduce the total regulation impact.

$$Share_i = \frac{\sigma_T^2 + \sigma_i^2 - \sigma_{T-i}^2}{2\sigma_T} \qquad [2.5]$$

We will use the general allocation method (Equation 2.5) to analyze the impacts various individual renewable generators have on the overall system's regulation requirements. These impacts will be calculated hourly and summarized monthly and annually. Differences among technologies, locations, and sizes will be analyzed and reported on.

Calculated hourly regulation requirements will be compared with hourly regulation purchases by the CAISO. Purchased regulation will then be allocated back to individuals. Hourly regulation costs will be used to allocate the cost of regulation back to individuals. This guarantees that the correct amount of regulation is accounted for. All of the CAISO's regulation purchases are allocated based upon the short-term variability impacts of the loads and renewable generators.

2.2.4 DATA REQUIREMENTS

Studying regulation requires one-minute, synchronized, integrated-energy, time series data for total control area load and the individual renewable resources of interest. The complete data list is:

One minute, synchronized, integrated-energy, time series data for:

- Total load
- Each renewable generator of interest

Experience has shown that it is also wise to perform an energy balance around the control area to assure data integrity. This requires 1-minute data for total generation, net actual imports/exports, net scheduled imports/exports, system frequency (and the frequency bias), and ACE. The complete data list is:

One minute, synchronized, integrated-energy, time series data for:

- Total generation

- Net actual imports/exports
- Net scheduled imports/exports
- Area control error (ACE)
- Frequency (and frequency bias) – often provided as a deviation from scheduled frequency

Regulation analysis requires only one data elements, plus one for each renewable generator of interest, each minute. Verifying data integrity requires an additional five data elements each minute.

The CAISO runs hourly markets for regulation up and regulation down. Price and quantity data from these markets is needed in order to determine impacts on the quantity of regulating resources procured and the cost of the additional regulation.

- Hourly regulation-up price
- Hourly regulation-down price
- Hourly MW of regulation-up procured (hour ahead and real-time)
- Hourly MW of regulation-down procured (hour ahead and real-time)
- Hourly MW of regulation-up self provided
- Hourly MW of regulation-down self provided

The amount of data that is collected and analyzed is a practical tradeoff. It is probably not practical to collect a full year of data (525,600 minutes) for Phase I. At a minimum, several days of data from each season and under various operating conditions should be included. Weekdays and week ends should be included to capture the full range of system loading.

Table 2.1 Detailed Regulation Data Requirements

1. system load (MW) [1 min]
2. system generation (MW) [1 min]
3. system frequency (Hz) [1 min]
4. frequency schedule (Hz) [1 min]
5. control area frequency bias (MW/0.1Hz) [1 min]
6. ACE (MW) [1 min]
7. actual tie flows (MW) [1 min]
8. scheduled tie flows (MW) [1 min]
9. aggregated renewable generation (MW) [1 min]
    a. biomass
    b. geothermal
    c. small hydro
    d. solar photovoltaic
    e. solar thermal
    f. wind
10. an individual renewable generator (MW) [1 min]
    a. biomass
    b. geothermal
    c. small hydro

    d. solar photovoltaic
    e. solar thermal
    f. wind
11. an individual conventional generator that is not on AGC or ADS (MW) [1 min]
12. regulation up purchased (MW) [1 hr]
13. regulation down purchased (MW) [1 hr]
14. self-provided regulation up (MW) [1 hr]
15. self-provided regulation down (MW) [1 hr]
16. hourly regulation up cost ($/MWh) [1 hr]
17. hourly regulation down cost ($/MWh) [1 hr]

2.2.5 STEP-BY-STEP ANALYSIS METHODOLOGY

The following is a step-by-step listing of the proposed regulation analysis methodology which will be applied to each of the eligible renewable technologies. Inputs are explicitly listed if they are raw data or if they are not output generated in a previous step.

1. Verify data consistency by looking at total system inflows, outflows, generation, and load.

$$ACE(t) = [NI_A(t) - NI_S(t)] - 10\beta[(F_A(t) - F_S(t)] - I_{ME}(t) \qquad [2.6]$$

$$NI_A(t) = G(t) - L(t) \qquad [2.7]$$

Table 2.2 Verify Data Consistency

Inputs

	Data description		**Units**	**Sampling rate**
a.	L	total actual system load	MW	1 minute
b.	G	total actual system generation	MW	1 minute
c.	F_A	actual system frequency	Hz	1 minute
d.	F_S	scheduled system frequency	Hz	1 minute
e.	ACE	area control error	MW	1 minute
f.	NI_A	actual net tie flows	MW	1 minute
g.	NI_S	scheduled net tie flows	MW	1 minute
h.	β	control area frequency bias	$MW/0.1\,Hz$	1 minute

2. Calculate 15 minute rolling average to use as a surrogate for the short term forecast.

$$L_{s_2}(t) = \overline{L_{15}}(t) = \frac{\sum_{x=-7\,\text{min}}^{7\,\text{min}} L(t+x)}{15} \qquad [2.8]$$

$$g_{i,s_2}(t) = \overline{g_{i,15}}(t) = \frac{\sum_{x=-7\,\mathrm{min}}^{7\,\mathrm{min}} g_i(t+x)}{15} \qquad [2.9]$$

Table 2.3 Estimate Short Term Forecast From Rolling Average Surrogate

Inputs

	Data description		Units	Sampling rate
a.	L	total system load	MW	1 minute
b.	g_B	biomass generation	MW	1 minute
c.	g_G	geothermal generation	MW	1 minute
d.	g_H	small hydro generation	MW	1 minute
e.	g_{ST}	solar thermal generation	MW	1 minute
f.	g_{SP}	solar photovoltaic generation	MW	1 minute
g.	g_W	wind generation	MW	1 minute
h.	g_C	sample non-controlled conventional generation	MW	1 minute

Outputs

	Data description		Units	Sampling rate
a.	L_{s_2}	short term load forecast	MW	1 minute
b.	g_{B,s_2}	short term forecast of biomass generation	MW	1 minute
c.	g_{G,s_2}	short term forecast of geothermal generation	MW	1 minute
d.	g_{H,s_2}	short term forecast of small hydro generation	MW	1 minute
e.	g_{ST,s_2}	short term forecast of solar thermal generation	MW	1 minute
f.	g_{SP,s_2}	short term forecast of solar photovoltaic generation	MW	1 minute
g.	g_{W,s_2}	short term forecast of wind generation	MW	1 minute
h.	g_{C,s_2}	short term forecast of sample non-controlled conventional generation	MW	1 minute

3. Calculate the raw regulation component by subtracting the short term forecast from the actual data.

$$r_L(t) = L(t) - L_{s_2}(t) \qquad [2.10]$$

$$r_i(t) = g_i(t) - g_{i,s_2}(t) \qquad [2.11]$$

Table 2.4 Calculate Regulation Component by Subtracting Short Term Forecast

Outputs

	Data description		Units	Sampling rate
a.	r_L	regulation component of total system load	MW	1 minute
b.	r_B	regulation component of biomass generator(s)	MW	1 minute
c.	r_G	regulation component of geothermal generator(s)	MW	1 minute
d.	r_H	regulation component of small hydro generator(s)	MW	1 minute
e.	r_{ST}	regulation component of solar thermal generator(s)	MW	1 minute
f.	r_{SP}	regulation component of solar photovoltaic generator(s)	MW	1 minute
g.	r_W	regulation component of wind generator(s)	MW	1 minute
h.	r_C	regulation component of sample non-controlled conventional generator(s)	MW	1 minute

4. Calculate the difference between the regulation component of the resource of interest and the regulation component of the total system load. The difference is the total system regulation requirement if the resource of interest was not present.

$$\Delta r_i(t) = r_L(t) - r_i(t) \qquad [2.12]$$

Table 2.5 Calculate Total System Regulation Less Resource of Interest

Outputs

	Data description		Units	Sampling rate
a.	Δr_B	total system regulation without biomass generator(s)	MW	1 minute
b.	Δr_G	total system regulation without geothermal generator(s)	MW	1 minute
c.	Δr_H	total system regulation without small hydro generator(s)	MW	1 minute
d.	Δr_{ST}	total system regulation without solar thermal generator(s)	MW	1 minute
e.	Δr_{SP}	total system regulation without solar	MW	1 minute

		photovoltaic generator(s)		
f.	Δr_W	total system regulation without wind generator(s)	MW	1 minute
g.	Δr_C	total system regulation without sample non-controlled conventional generator(s)	MW	1 minute

5. Calculate the hourly standard deviation of the regulation values determined in the previous two steps.

$$\sigma_T(t) = \underset{x=0\rightarrow 59\,\min}{\sigma}\left(r_L\,(t+x)\right) \qquad [2.13]$$

$$\sigma_i(t) = \underset{x=0\rightarrow 59\,\min}{\sigma}\left(r_i(t+x)\right) \qquad [2.14]$$

$$\sigma_{T-i}(t) = \underset{x=0\rightarrow 59\,\min}{\sigma}\left(\Delta r_i(t+x)\right) \qquad [2.15]$$

Table 2.6 Calculate Statistical Metrics of Regulation From Existing Data

Outputs

	Data description		**Units**	**Sampling rate**
a.	σ_T	standard deviation of regulation component of total system load	MW	1 hour
b.	σ_B	standard deviation of regulation component of biomass generator(s)	MW	1 hour
c.	σ_G	standard deviation of regulation component of geothermal generator(s)	MW	1 hour
d.	σ_H	standard deviation of regulation component of small hydro generator(s)	MW	1 hour
e.	σ_{ST}	standard deviation of regulation component of solar thermal generator(s)	MW	1 hour
f.	σ_{SP}	standard deviation of regulation component of solar photovoltaic generator(s)	MW	1 hour
g.	σ_W	standard deviation of regulation component of wind generator(s)	MW	1 hour
h.	σ_C	standard deviation of regulation component of sample non-controlled conventional generator(s)	MW	1 hour
i.	σ_{T-B}	standard deviation of regulation of system w/out biomass generator(s)	MW	1 hour
j.	σ_{T-G}	standard deviation of regulation of system w/out geothermal generator(s)	MW	1 hour
k.	σ_{T-H}	standard deviation of regulation of system w/out small hydro generator(s)	MW	1 hour

l.	$\sigma_{T\text{-}ST}$	standard deviation of regulation of system w/out solar thermal generator(s)	MW	1 hour
m.	$\sigma_{T\text{-}SP}$	standard deviation of regulation of system w/out solar photovoltaic generator(s)	MW	1 hour
n.	$\sigma_{T\text{-}W}$	standard deviation of regulation of system w/out wind generator(s)	MW	1 hour
o.	$\sigma_{T\text{-}C}$	standard deviation of regulation of system w/out sample non-controlled conventional generator(s)	MW	1 hour

6. Allocate the regulation share to the resource of interest.

$$\hat{R}_i(t) = Share_i(t) = \frac{\sigma_T^2(t) + \sigma_i^2(t) - \sigma_{T-i}^2(t)}{2\sigma_T(t)} \qquad [2.16]$$

Table 2.7 Allocate Regulation Share for Each Generator Type

Outputs

		Data description	Units	Sampling rate
a.	$\hat{R}_B$	regulation share of biomass generation	MW	1 hour
b.	$\hat{R}_G$	regulation share of geothermal generation	MW	1 hour
c.	$\hat{R}_H$	regulation share of small hydro generation	MW	1 hour
d.	$\hat{R}_{ST}$	regulation share of solar thermal generation	MW	1 hour
e.	$\hat{R}_{SP}$	regulation share of solar photovoltaic generation	MW	1 hour
f.	$\hat{R}_W$	regulation share of wind generation	MW	1 hour
g.	$\hat{R}_c$	regulation share of sample non-controlled conventional generation	MW	1 hour

7. Determine the regulation requirement of each resource of interest. The relationship between the regulation share and regulation requirement is assumed to be the same as the relationship between the total regulation impact (σ_T) calculated above and the actual regulation that was acquired during the time period.

$$R_i(t) = \frac{\hat{R}_i(t) R_{actual}(t)}{\sigma_T(t)} \qquad [2.17]$$

Table 2.8 Calculate Actual Regulation Share for Each Generator Type

Inputs

	Data description		Units	Sampling rate
a.	R_{actual}	actual regulation (purchased and self provided, up and down) market data	MW	1 hour

Outputs

	Data description		Units	Sampling rate
a.	R_B	regulation requirement of biomass generator(s)	MW	1 hour
b.	R_G	regulation requirement of geothermal generator(s)	MW	1 hour
c.	R_H	regulation requirement of small hydro generator(s)	MW	1 hour
d.	R_{ST}	regulation requirement of solar thermal generator(s)	MW	1 hour
e.	R_{SP}	regulation requirement of solar photovoltaic generator(s)	MW	1 hour
f.	R_W	regulation requirement of wind generator(s)	MW	1 hour
g.	R_C	regulation requirement of sample non-controlled conventional generator(s)	MW	1 hour

8. Calculate actual hourly regulation cost by multiplying regulation requirement by hourly regulation cost. Calculate the change in cost that results from each renewable generator.

$$COST_R(t) = R_i(t) \cdot RATE_R(t) \qquad [2.18]$$

Table 2.9 Calculate Actual Regulation Cost for Each Generator Type

Inputs

	Data description		Units	Sampling rate
a.	$RATE_R$	actual regulation rate (up an down) market data	\$/MW-hr	1 hour

Outputs

	Data description		Units	Sampling rate
a.	$COST_{R,B}$	regulation cost of biomass generator(s)	\$	1 hour

b.	$COST_{R,G}$	regulation cost of geothermal generator(s)	$	1 hour
c.	$COST_{R,H}$	regulation cost of small hydro generator(s)	$	1 hour
d.	$COST_{R,ST}$	regulation cost of solar thermal generator(s)	$	1 hour
e.	$COST_{R,SP}$	regulation cost of solar photovoltaic generator(s)	$	1 hour
f.	$COST_{R,W}$	regulation cost of wind generator(s)	$	1 hour
g.	$COST_{R,C}$	regulation cost of sample non-controlled conventional generator(s)	$	1 hour

2.3 Hourly Load Following

While the CAISO procures regulation reserves to compensate for the minute-to-minute variability of aggregate load and non-dispatchable generation the slower load following is compensated for through the short-term energy market and energy imbalance. With California’s market structure that requires balanced schedules there is no direct cost for load following if resources follow their stated schedules. Costs are incurred when schedules are missed and the ISO is required to utilize responsive generation available through the supplemental energy stack. If the scheduling error is nonbiased (the generator is as likely to over generate as under generate in any given interval) then the imbalance energy tends to cancel. Costs are incurred if moving up in the supplemental energy stack is more expensive than moving down.

As with regulation, there are aggregation benefits when evaluating load following and energy imbalance. One generator may be over generating at the same time another is under generating, resulting in a reduced impact on the overall system. As with regulation, load following and scheduling error cost can not be evaluated in isolation. It is necessary to examine the impact of the individual in concert with the total system.

This proposed methodology utilizes actual operational data (Table 2.10) and experience from the California power system to capture how the California energy and ancillary service markets value load following and handle problems such as unit commitment and optimal dispatch. The methodology also explicitly does *not* consider the impact renewable generators have in displacing other generation and therefore moving the system to another point on the dispatch curve. Typically this should suppress the energy price. This method will capture any impact on increasing load following (maneuverability) requirements that are imposed by renewable generators.

Actual ex-post supplemental energy prices are used to calculate the load following cost for each renewable generator. In fact, the energy imbalance of the renewable generator will change the beep stack dispatch and, consequently, the hourly clearing price for supplemental energy. The group believes that this is a small effect that can be safely ignored. This assumption could be checked by obtaining the beep bid stack for each 10 minute period and calculating an adjusted supplemental energy price for each ten minute period for each generator evaluated.

Table 2.10 Additional Load Following Data Requirements

1. hourly system load 1 hour forecasts (MW)
2. actual supplemental energy ex-post pricing ($/MWh)
3. supplemental energy purchase (MW)

2.4 Load Following Analysis Methodology

Our approach will examine load and generation data from California for each hour. The hour ahead load forecast is available. We will utilize simple persistence models to generate hour ahead forecasts for each of the non-dispatchable renewable generators.

The CAISO clears the supplemental energy market every ten minutes. The supplemental energy bid stack for each ten minute market is saved. The amount of energy that must be obtained from the supplemental energy market each ten minutes can be calculated by taking the difference between the rolling average for the load less each of the renewable generators under investigation and the corresponding hourly energy forecasts. The cost of the energy imbalance for each renewable generation type can then be calculated for each ten minute period using the appropriate supplemental energy bid stack or ex-post prices.

The following is a step-by-step listing of the proposed analysis methodology.

1. Calculate the hour ahead forecast of the generators of interest (note that the hour ahead forecast of the total system load is available from CAISO). The analysis will be performed with two hour ahead forecasts: a best-case, perfect model with zero error in which the actual generation data is used for the forecast; and a "worst-case" model which uses a simple persistence model.

$$g_{i,s_1}(t) = \begin{cases} \dfrac{\sum_{x=1\,min}^{60\,min} g_i(t-x)}{60} & \text{simple persistence model, where } g_{i,s_1} \text{ is determined hourly} \\ g_i(t) & \text{perfect forecast, where } g_{i,s_1} \text{ is determined each minute} \end{cases} \qquad [2.19]$$

Table 2.11 Calculate Hour Ahead Forecasts

Inputs

	Data description		**Units**	**Sampling rate**
a.	g_B	biomass generation	MW	1 minute
b.	g_G	geothermal generation	MW	1 minute
c.	g_H	small hydro generation	MW	1 minute

d.	g_{ST}	solar thermal generation	MW	1 minute
e.	g_{SP}	solar photovoltaic generation	MW	1 minute
f.	g_{W}	wind generation	MW	1 minute
g.	g_{C}	generation of sample non-controlled conventional generator(s)	MW	1 minute

Outputs

	Data description		Units	Sampling rate
a.	g_{B,s_1}	hour ahead forecast of biomass generation	MW	1 minute
b.	g_{G,s_1}	hour ahead forecast of geothermal generation	MW	1 minute
c.	g_{H,s_1}	hour ahead forecast of small hydro generation	MW	1 minute
d.	g_{ST,s_1}	hour ahead forecast of solar thermal generation	MW	1 minute
e.	g_{SP,s_1}	hour ahead forecast of solar photovoltaic generation	MW	1 minute
f.	g_{W,s_1}	hour ahead forecast of wind generation	MW	1 minute
g.	g_{C,s_1}	hour ahead forecast of generation of sample non-controlled conventional generator(s)	MW	1 minute

2. Calculate the ten-minute average supplemental energy requirements for load by itself and then for the load plus the non-controlled generator of interest. The supplemental energy requirement in this case is defined to be the difference between the hour ahead forecast and the short term forecast. The short term forecast is again taken as a 15 minute rolling average, as detailed in Section 2.2.2 and Section 2.2.5 Step 3.

$$lf_L(t) = \frac{\sum_{x=1\,\mathrm{min}}^{10\,\mathrm{min}} \left(L_{s_2}(t+x) - L_{s_1}(t+x) \right)}{10} \qquad [2.20]$$

$$lf_i(t) = \frac{\sum_{x=1\,\mathrm{min}}^{10\,\mathrm{min}} \left[\left(L_{s_2}(t+x) + g_{i,s_2}(t+x) \right) - \left(L_{s_1}(t+x) + g_{i,s_1}(t+x) \right) \right]}{10} \qquad [2.21]$$

Table 2.12 Calculate Load Following Requirements

Inputs

	Data description		Units	Sampling rate
a.	L_{s_2}	short term forecast of total system load	MW	1 minute

b.	g_{B,s_2}	short term forecast of biomass generation	MW	1 minute
c.	g_{G,s_2}	short term forecast of geothermal generation	MW	1 minute
d.	g_{H,s_2}	short term forecast of small hydro generation	MW	1 minute
e.	g_{ST,s_2}	short term forecast of solar thermal generation	MW	1 minute
f.	g_{SP,s_2}	short term forecast of solar photovoltaic generation	MW	1 minute
g.	g_{W,s_2}	short term forecast of wind generation	MW	1 minute
h.	g_{C,s_2}	short term forecast of generation of sample non-controlled conventional generator(s)	MW	1 minute

Outputs

	Data description		Units	Sampling rate
a.	lf_L	supplemental energy requirement of load alone	MW	10 minute
b.	lf_B	supplemental energy requirement of biomass generator(s)	MW	10 minute
c.	lf_G	supplemental energy requirement of geothermal generator(s)	MW	10 minute
d.	lf_H	supplemental energy requirement of small hydro generator(s)	MW	10 minute
e.	lf_{ST}	supplemental energy requirement of solar thermal generator(s)	MW	10 minute
f.	lf_{SP}	supplemental energy requirement of solar photovoltaic generator(s)	MW	10 minute
g.	lf_W	supplemental energy requirement of wind generator(s)	MW	10 minute
h.	lf_C	supplemental energy requirement of non-controlled conventional generator(s)	MW	10 minute

3. Calculate the average supplemental energy cost for the non-controlled generator of interest. The load following energy cost is taken from the supplemental energy stack or ex-post price data.

$$COST_{lf}(t) = [\phi_i(t) - \phi_L(t)] \cdot RATE_{lf}(t) \qquad [2.22]$$

Table 2.13 Calculate Load Following Costs

Inputs

	Data description	Units	Sampling rate

a.	RATE_{lf}	actual supplemental energy rate market data	$/MWh	1 hour

Outputs

	Data description		Units	Sampling rate
a.	$\text{COST}_{lf,\text{B}}$	supplemental energy cost of biomass generator(s)	$	1 hour
b.	$\text{COST}_{lf,\text{G}}$	supplemental energy cost of geothermal generator(s)	$	1 hour
c.	$\text{COST}_{lf,\text{H}}$	supplemental energy cost of small hydro generator(s)	$	1 hour
d.	$\text{COST}_{lf,\text{ST}}$	supplemental energy cost of solar thermal generator(s)	$	1 hour
e.	$\text{COST}_{lf,\text{SP}}$	supplemental energy cost of solar photovoltaic generator(s)	$	1 hour
f.	$\text{COST}_{lf,\text{W}}$	supplemental energy cost of wind generator(s)	$	1 hour
g.	$\text{COST}_{lf,\text{C}}$	supplemental energy cost of sample non-controlled conventional generator(s)	$	1 hour

2.5 Regulation Allocation Methodology

This regulation impact allocation method was developed by Oak Ridge National Laboratory to deal with nonconforming loads (Kirby and Hirst, 2000). It works equally well with uncontrolled generators that are not using either AGC or ADS. The methodology meets several desirable objectives:

- Recognize positive and negative correlations
- Be independent of subaggregations
- Be independent of order in which generators or loads are added to system
- Allow disaggregation of as many or few components as desired

The methodology has been used by a number of analysts to analyze the regulation impacts of loads, conventional generators that are not on AGC or ADS, and non-dispatchable renewable generators.

We can think of regulation as a vector and not just a magnitude. For example, start with load *A*. It might be a single house or an entire control area with a regulation impact of 8. Consider another load *B* with a regulation impact of 6 that we want to combine with *A*. If loads *A* and *B* are perfectly correlated positively, they add linearly, as shown in the top of Figure 2.2. If the two loads are perfectly correlated negatively, their regulation impacts would add as shown in the middle of Figure 2.2. Typically, loads are completely uncorrelated and the regulation requirement for the total is the square root of the sum of the squares, or 10 in this case (bottom of Figure 2.2).

Multiple uncorrelated loads are always at 90 degrees to every other load. They are also at 90 degrees to the sum of all the other loads. This characteristic requires adding another dimension each time another load is added, which is difficult to visualize beyond three loads. Fortunately, the math is not any more complex. The fact that each new uncorrelated load is at 90 degrees to every other load and to the total of all the other loads is quite useful. The analysis of any number of multiple loads can always be broken down into a two-element problem, the single load and the rest of the system.

Return to the two-load example but consider the more general case where loads *A* and B are neither perfectly correlated nor perfectly uncorrelated. We may know the magnitude of *A* and the magnitude of *B*, but we do not know the magnitude of the total without measuring it directly (i.e., we do not know the *direction* of each vector). We can, however, measure the total regulation requirement and use this vector method to *allocate* the total requirement among the individual contributors.

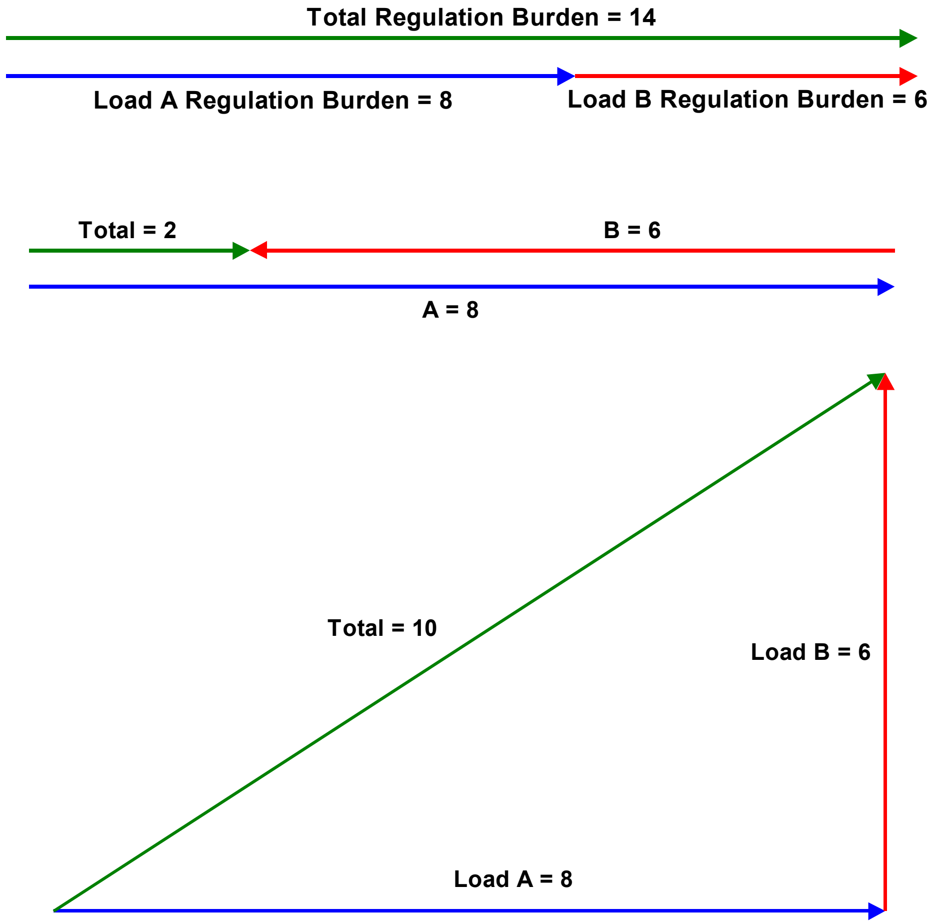


Figure 2.2 The relationships among the regulation components (A and B) and the total if A and B are positively correlated (top), negatively correlated (middle), or uncorrelated (bottom).

We know the total regulation requirement because we meter it directly as the aggregated regulation requirement of the control area. We can know the regulation requirement of any load by metering it also. We can know the regulation requirement of the entire system less the single load we are interested in by calculating the difference between the system load and the single load at every time step, separating regulation from load following, and taking the standard deviation of the difference signal. Knowing the magnitudes of the three regulation requirements, we can draw a vector diagram showing how they relate to each other (Figure 2.3).

How much of the total regulation requirement is the responsibility of load *A*? We can calculate the amount of A that is aligned with the total and the amount of *B* that is aligned with the total. We can do this geometrically (as shown below) or with a correlation analysis.

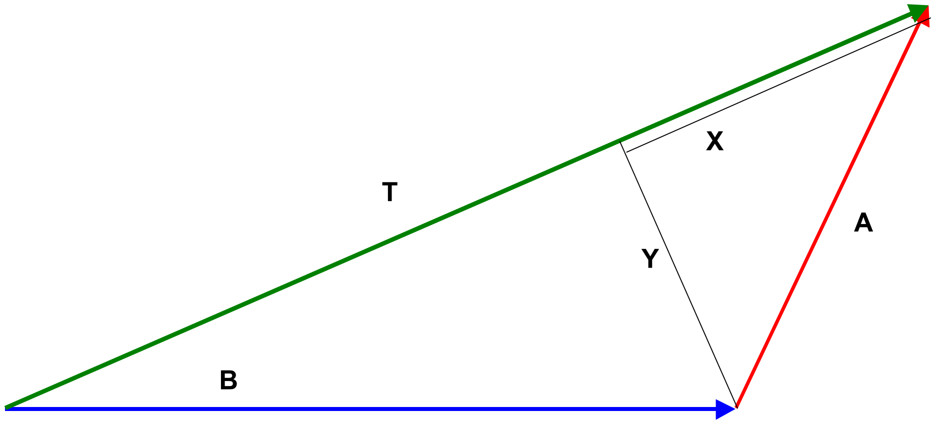


Figure 2.3 The relationship among the regulation impacts of loads A and B and the total (T) when A and B are neither perfectly correlated nor perfectly uncorrelated.

Y is perpendicular to the total regulation T (uncorrelated). X is aligned with T (correlated). A's contribution to T is X. Knowing A, B, and T, we can calculate X. (We could also calculate Y, but there is no need to do so.) We can write two equations relating the lengths of the various elements:

$$A^2 = X^2 + Y^2 \tag{2.1}$$

$$B^2 = (T - X)^2 + Y^2 \tag{2.2}$$

Subtract equation 2.2 from equation 2.1 to get,

$$A^2 - B^2 = X^2 - (T - X)^2 + Y^2 - Y^2$$

$$A^2 - B^2 = X^2 - (T^2 - TX - TX + X^2) = 2TX - T^2$$

Solving for X (load A's contribution to the total T) yields,

$$X = (A^2 - B^2 + T^2)/2T \tag{2.3}$$

We can decompose a collection of any number of loads into a two-load problem consisting of the load we are interested in and the rest of the system without that load (Figure 2.4). We can solve Equation 2.3 for as many individual loads as we wish. Variable T remains the total regulation requirement, variable A becomes each individual load's regulation requirement, and variable B becomes the regulation requirement of the total system *less* the specific load of interest.

This allocation method works well with any combination of individually metered loads and load profiling for the remaining loads. The load profiling can be as simple as making the usual assumption that the other loads' regulation requirements are proportional to their energy requirements. Or measurements of a sample set can be taken to determine the magnitude of their regulation impacts. This vector-allocation method is used to determine the regulation impact of each of the metered loads. The residual regulation impact is then allocated among the remaining loads, assuming they are perfectly uncorrelated.

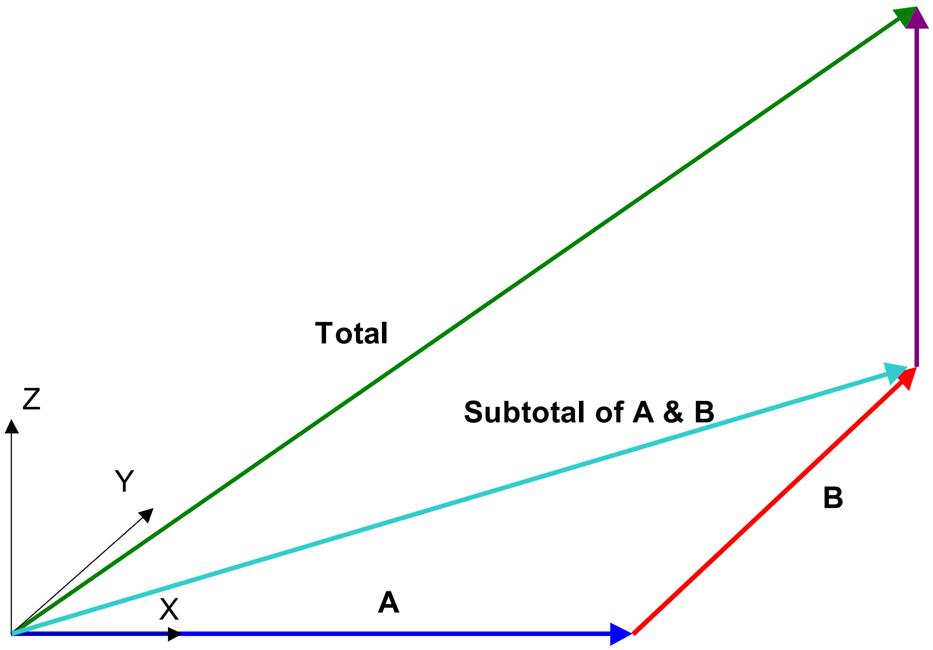


Figure 2.4 Application of Vector-Allocation Method to the Case with More Than Two Loads.

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3 Ancillary Services Cost Analysis: Method 2

YURI MAKAROV, CALIFORNIA INDEPENDENT SYSTEM OPERATOR

The methodology presented in this section was developed by Yuri Makarov of CAISO.

3.1 Overview

The approach reported in this document is proposed by CAISO to properly evaluate the amount of supplemental and regulation reserves required for any operating hour, any operating day to reliably accommodate renewable resources into an electrical power system.

The proposed approach has the following features:

- The technique is based on realistic hour-ahead scheduling and real-time dispatch processes; it is flexible enough to account for the actual forecasting and scheduling errors and reflect specific practices of different Control Areas.
- The effect of any change or improvement can be analyzed (for example, the gain in regulation and supplemental reserve requirements due to introducing advanced hour-ahead and real-time forecasting services for system resources).
- The approach determines the upper and lower statistical boundaries of the additional regulation and supplemental energy reserves; depending on the specifics of the scheduling and real-time dispatch processes, it allows assigning asymmetric quantities for the required incremental and decremental reserves.
- The approach accounts for any short-term "overshooting" or "undershooting" of the scheduling and real-time dispatch processes against the actual generation; the corresponding deviation is included in the newly proposed metric (for example, systematic "overshooting" or "undershooting" during ramping periods).
- The methodology automatically accounts for statistical correlations of a generation resource with the total system load, the rest of the generators, the interties, and the interconnection frequency error. In particular, the approach is capable of determining the intervals, where the resource variations help to reduce the required amount of regulation.
- This assessment is based on basic quantities that determine the regulation and supplemental energy requirements: the supplemental energy imbalance and the Area Control Error incurred by deviations of a generation resource from its schedule and real-time dispatch.

- The technique is capable of evaluating the impacts of individual resources as well as the total impacts of their aggregates (for example, the impacts of the regional MW production by the resource type). Two cases are distinguished depending on the type of the scheduling and real time dispatch processes: direct explicit separation and separation through the participation factors assigned for each specific project.

- The by-project participation factors are determined for each individual project/aggregate depending not only on its variance, but also on its systematic deviation from the schedule. This helps to distinguish the impact of generation resources equipped with advanced forecasting service from impacts of the less predictable resources.

- Because the MW impact is determined on the hourly basis, determining the corresponding dollar impact becomes a routine exercise.

3.2 Variability Metrics of Unscheduled Impacts

In this section we establish statistical metrics for measuring the impact of an arbitrary resource on the supplemental energy and regulation requirements.

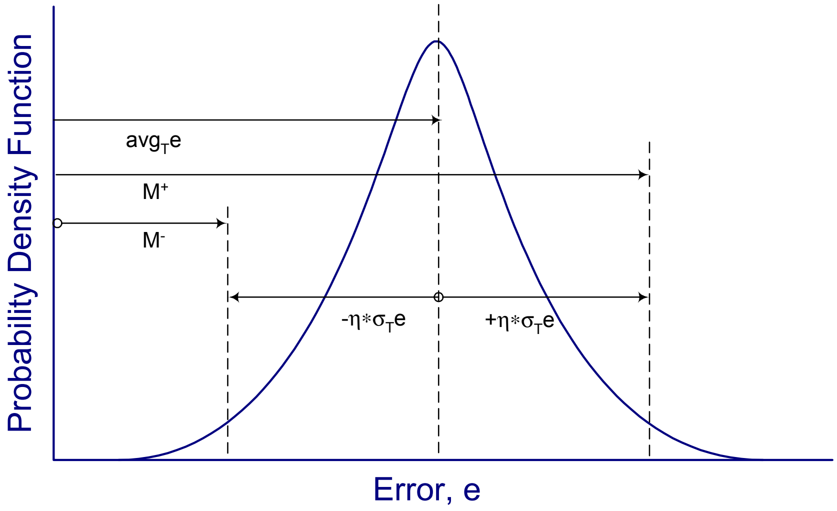

Figure 3.1 Resource Variability Metrics

The resource variability metrics are defined as the “negative” and “positive” parts of the confidence interval of scheduling errors – see Figure 3.1:

$$\boxed{\begin{aligned} M^- &= \mathrm{avg}_T e - \eta \cdot \sigma_T e \\ M^+ &= \mathrm{avg}_T e + \eta \cdot \sigma_T e \end{aligned}}$$

where $e(t)$ - scheduling error; in the sequel, we will additionally specify how this error is calculated;

T - analyzed interval;

$\mathrm{avg}_T e$ - average scheduling error;

$\sigma_T e = \sqrt{\mathrm{var}_T e}$ - standard deviation;

$\mathrm{var}_T\, e$ - variance of forecasting/scheduling error;

η - a multiplier determining the desired size of the confidence interval, e.g. $\eta = 1.67$ gives a 90% probability confidence interval, and $\eta = 3$ corresponds to 97.8% (the distribution of e is assumed to be normal).

Depending on average scheduling error, $\mathrm{avg}_T e$, the proposed metrics $M^{\pm}$ may become asymmetrical reflecting the bias of the scheduling process; this bias is further translated into asymmetric incremental and decremental requirements.

Parameters $M_j^{\pm}$ are determined for each individual resource or zone j, while $M^{\pm}$ is determined for the entire resource (for instance, for the total area wind generation).

Generally, $\sum_j M_j \neq M_e$ if the individual resource errors are statistically dependent.

By analyzing these new metrics, one can determine the incremental impacts of a resource by comparing the probability distributions evaluated with and without the analyzed impact included - see Distributions 2 and 1 in Figure 3.2.

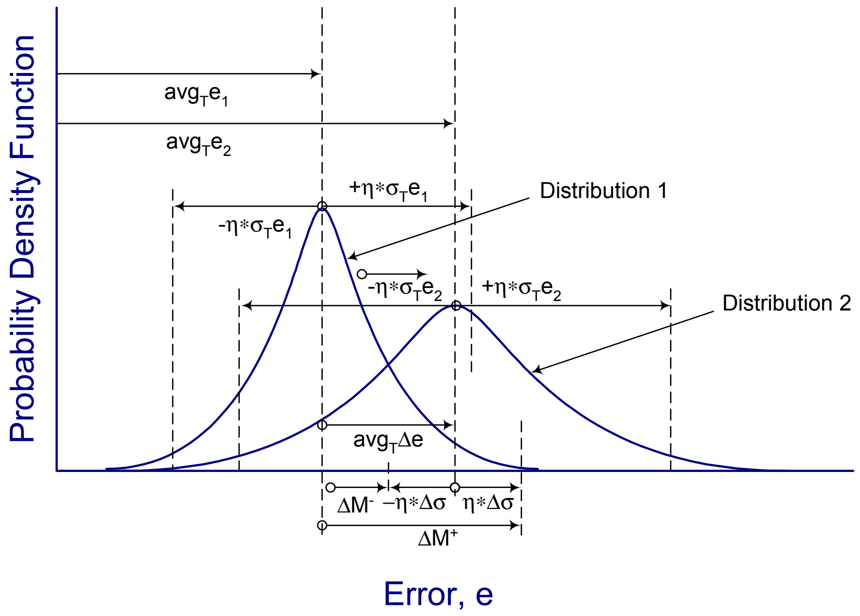

Figure 3.2 Incremental Impacts of an Arbitrary Resource

The incremental impacts $\Delta M^{\pm}$ consist of the impact on the average scheduling error $avg_T\Delta e = avg_Te_2 - avg_Te_1$ and the impact on the width of the confidence interval $\pm\eta\cdot\Delta\sigma = \pm(\eta\cdot\sigma_Te_2 - \eta\cdot\sigma_Te_1)$:

$$\boxed{\Delta M^{\pm} = avg_T\Delta e \pm \eta\cdot\Delta\sigma}$$

Normally, we would expect that $\Delta M^+ \geq \Delta M^-$. Nevertheless, for some limited intervals *T*, it may happen that $\Delta M^+ < \Delta M^-$. This would mean that, within these intervals, the resource actually helps to reduce the variance of the resulting regulation or supplemental energy requirements.

3.3 Impact On Supplemental Energy Reserve Requirements

The additional supplemental energy requirement induced by a resource is caused by the difference $\Delta s(t)$ between the resulting real-time dispatch $s_2(t)$ and hour-ahead $s_1(t)$ schedule of the analyzed resource– Figure 3.3:

$$\Delta s(t) = s_2(t) - s_1(t)$$

The real-time dispatch $s_2(t)$ includes the hour ahead schedule plus all real-time automatic and manual supplemental energy adjustments made to the hour-ahead schedule (regulation is not included).

For example, at the CAISO, the hour-ahead schedule is determined by the Scheduling Coordinators and submitted to the CAISO 2.5 hours before the actual operating hour begins.

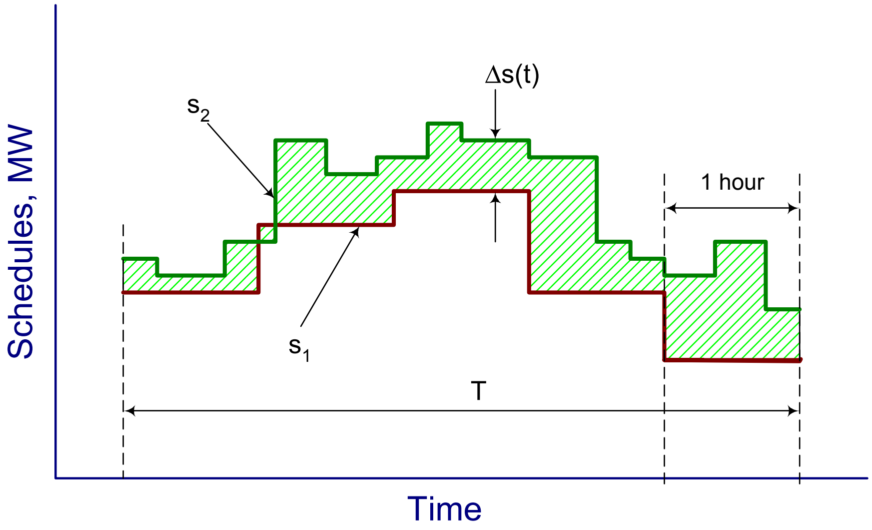

Figure 3.3 Real Time Schedule vs. Hour-Ahead Schedule

More generally, the real-time dispatches can be either explicit (actual) or implicit (simulated).

The <u>explicit actual schedules</u> are available when the analyzed resource is forecasted and scheduled individually in a transparent fashion. For example, individual wind generation projects participating in the California ISO market integration initiative will have the explicit hour-ahead schedules, $s_1(t)$.

The <u>implicit simulated schedules</u> have to be used whenever the explicit schedules are not available. This appears when the analyzed resource is a part of an aggregated actual schedule, for example, obtained as a result of a real-time regional generation forecast, or when an explicit schedule is not available at all, for instance, when the resource unscheduled variations are only addressed in the course of the real-time Control Area balancing (e.g. through instructions issued by the real-time Dispatcher).

A resource is <u>directly separable</u> when it has both actual hour-ahead, $s_1(t)$, and real-time $s_2(t)$ schedules explicitly available. For the directly separable resources, the analysis is straightforward as described in this Section.

If the expected individual generation is only available through an aggregate schedule (e.g. through the regional schedule), it becomes a directly non-separable resource. The separation of its contribution becomes artificial and approximate. It can be done by simulating the implicit schedules, or by determining a "fair share" γ_j of each individual resource in an aggregate based on an acceptable convention or rule.

The approach suggested in this paper is flexible enough to accommodate all type of schedules analyzed above.

A nonzero process $\Delta s(t)$ results in additional supplemental energy reserve requirements. However, the required addition does not manifest itself directly as $\Delta s(t)$. Correlations of $\Delta s(t)$ with the changing load, interconnection frequency, and other schedules can modify the primary additional supplemental energy requirement $\Delta s(t)$.

A proper evaluation can be made in the following way.

Without the power losses accounted for, schedule s_1 satisfies to the balancing condition:

$$G_{S1}(t) + s_1(t) - L_{S1}(t) - T_{S1}(t) = 0$$

where $G_{S1}(t)$ - is the total hour-ahead scheduled generation without the analyzed hour-ahead schedule accounted for;

$L_{S1}(t)$ - hour-ahead load schedule; and

$T_{S1}(t)$ - hour-ahead area interchange schedule.

The real-time dispatch $s_2(t)$ may be balanced (for example, as a result of applying the security constrained economic dispatch), or unbalanced (for instance, in the course of the manual ramp planning process, where the real-time Dispatcher may miscalculate the required size of supplemental energy instructions or intentionally make some temporary unbalanced decisions):

$$G_{S2}(t) + s_2(t) - L_{S2}(t) - T_{S2}(t) = E(t)$$

where $G_{S2}(t)$ - is the total real-time scheduled plus manually dispatched generation without the analyzed real-time resource schedule accounted for;

$L_{S2}(t)$ - is the real-time load forecast;

$T_{S1}(t)$ -real-time area interchange schedule, and

$E(t)$ - is the real-time scheduling and dispatch error. The value of $E(t)$ can be calculated for each moment *t* through the resulting real time generation schedule (plus the real-time dispatch instructions), real-time load forecast, and scheduled interchange.

The difference between these two schedules is

$$\Delta G_S(t) + \Delta s(t) - \Delta L_S(t) - \Delta T_S(t) = E(t) \Rightarrow$$
$$\mathrm{var}_T\, \Delta G_S(t) = \mathrm{var}_T\left[E(t) + \Delta L_S(t) + \Delta T_S(t) - \Delta s(t)\right]$$

where $\Delta L_S(t) = L_{S2} - L_{S1}$, $\Delta T_S(t) = T_{S2} - T_{S1}$ and $\Delta G_S(t) = G_{S2} - G_{S1}$.

Without $\Delta s(t)$, the variance of the required supplemental generation would be

$$\mathrm{var}_T\, \Delta G_S^{'}(t) = \mathrm{var}_T\left[E(t) + \Delta L_S(t) + \Delta T_S(t)\right]$$

By applying the proposed incremental resource variability metric (Section 3.2), we obtain the required additional supplemental energy reserves in the upward and downward directions:

$$\boxed{\Delta M_{SUP}^{+} = -\mathrm{avg}_T \Delta s(t) + \eta \cdot \sigma_T\left[E(t) + \Delta L_S(t) + \Delta T_S(t) - \Delta s(t)\right] - \eta \cdot \sigma_T\left[E(t) + \Delta L_S(t) + \Delta T_S(t)\right]}$$

and

$$\boxed{\Delta M_{SUP}^{-} = -\mathrm{avg}_T \Delta s(t) - \eta \cdot \sigma_T\left[E(t) + \Delta L_S(t) + \Delta T_S(t) - \Delta s(t)\right] + \eta \cdot \sigma_T\left[E(t) + \Delta L_S(t) + \Delta T_S(t)\right]}$$

It may happen, that the random quantities analyzed in this Section will not comply with the statistical hypothesis regarding their normal distribution. In this case, the M_{SUP}^{+} and M_{SUP}^{-} limits can be found using an alternative method that we have developed.

3.4 Impact On The Regulation Reserve Requirements

Consider the real-time dispatch error – see Figure 3.4:

$e(t) = g(t) - s_2(t)$ [a possible variant: $e(t) = g(t) - \tilde{s}_2(t)$]

where $g(t)$	- is the actual generation (e.g. 1-minute sliding average);
$s_2(t)$	- is the real-time dispatch; it includes the hour ahead schedule plus all real-time automatic and manual supplemental energy adjustments made to the hour-ahead schedule (regulation is not included).
$\tilde{s}_2(t)$	- is the simulated expected actual response of regulating units.

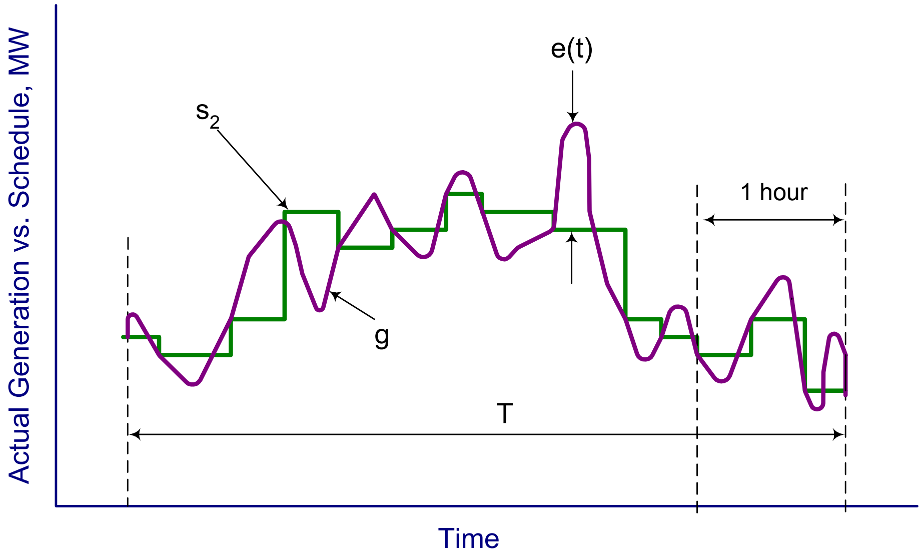

Figure 3.4 Actual Generation vs. Real-Time Dispatch Schedule

Analysis of the real-time dispatch $e(t)$ by itself is not very helpful because it does not account for possible correlations of $e(t)$ with random variations of load, generation, area interchange, and interconnection frequency. The actual additional regulation requirement caused by the analyzed resource can be determined through a statistical analysis of the Area Control Error:

$$ACE(t) = G'(t) + e(t) - L(t) - 10B(t) \cdot \Delta F(t) - T_S = ACE'(t) + \left[1 - \frac{B(t)}{B_{IC}}\right] e(t)$$

where

$G'(t)$ - is the total actual generation minus the real-time dispatch error;

$L(t)$ - total actual load;

$\Delta F(t)$ - interconnection frequency error;

$B(t)$ - Control Area frequency bias;

B_{IC} - Interconnection frequency bias;

$ACE'(t) = ACE(t) + \left[\frac{B(t)}{B_{IC}} - 1\right] \cdot e(t)$ - is the "would be" Area Control Error without the stress posed by the real time dispatch error.

Depending on the type of the Automatic Generation Control System (e.g. traditional or feedforward), the real-time regulation requirement is a function of ACE:

Regulation = $-\Re(ACE)$

Transformation $\Re$ represents a simplified rule mimicking the AGC transfer function (e.g. the dead zone and PI filtering in a traditional AGC system).

Using the metrics suggested in Section 3.2, the additional regulation reserve in the upward and downward directions needed to accommodate the analyzed resource is

$$\Delta M_{REG}^{+} = -\mathrm{avg}_T \left[\frac{B(t)}{B_{IC}} - 1\right] \cdot e(t) + \eta \cdot \sigma_T \Re\left(ACE\right) - \eta \cdot \sigma_T \Re\left(ACE'\right)$$

and

$$\Delta M_{REG}^{-} = -\mathrm{avg}_T \left[\frac{B(t)}{B_{IC}} - 1\right] \cdot e(t) - \eta \cdot \sigma_T \Re\left(ACE\right) + \eta \cdot \sigma_T \Re\left(ACE'\right)$$

respectively.

The frequency related term $\frac{B(t)}{B_{IC}}$ accounts for the impact of the analyzed resource on the interconnection frequency error. If the resource size is small, than $\frac{B(t)}{B_{IC}} \approx 0$.

At the present initial stage, we will consider $\Re$ as the identity transformation (i.e. we will not simulate the AGC function assuming that the actual ACE variations constitute the "true" regulation requirement).

As a result, the required additional regulation reserves reserve needed in the upward and downward directions is equal to

$$\boxed{\Delta M_{REG}^{+} = -\text{avg}_T \left[\frac{B(t)}{B_{IC}} - 1 \right] \cdot e(t) + \eta \cdot \sigma_T ACE - \eta \cdot \sigma_T ACE'}$$

and

$$\boxed{\Delta M_{REG}^{-} = -\text{avg}_T \left[\frac{B(t)}{B_{IC}} - 1 \right] \cdot e(t) - \eta \cdot \sigma_T ACE + \eta \cdot \sigma_T ACE'}$$

correspondingly.

3.5 Approximate Real-time Dispatcher Control Impacts

The real-time Dispatcher is capable of sending manual incremental and decremental instructions to the generation units listed in the supplemental energy stack. These instructions modify the real-time dispatch process $s_2 = s_2(t)$ and influence the hour-ahead scheduling error $e_1 = e_1(t)$ and real-time dispatch error $e_2 = e_2(t)$.

It should be noted that the actual impact of dispatcher's instruction is very complicated and somewhat controversial. For example, by issuing more instructions, the real-time Dispatcher can provide a tighter load following process and reduce the regulation reserve requirements, but at the same time, this strategy may result in increasing supplemental reserve needs.

The manual instructions issued by the real-time Dispatcher often make the individual resources contributions directly non-separable, and require some special treatment using, for example, the implicit simulated schedules. We have developed several approximate approaches to attack this problem:

(a) Through the implicit simulated real-time resource dispatches synchronized with the actual Dispatcher's instructions.

(b) Through the "fair share" conventions.

(c) Through an approximate statistical "success rate".

3.6 Assigning Supplemental Energy And Regulation Reserves

Because the directly non-separable resources are scheduled in aggregates, the share γ_j of a resource in an aggregate can be only assigned using a convention or rule, which we would call "a fair share convention". For a directly non-separable resource *j*, it is not possible to assign this share in a unique way. In this Section, we propose a new approximate rule that reflects the relative size (average generation) and relative variability of aggregated non-separable resources.

A general assumption used in the proposed rule is that the "fair share" of a non-separable resource in an aggregate depends on its size (average generation) and variability. For this purpose, we suggest to use a RMS-based measure because the RMS value reflects both the average and variance of a random variable:

$$rms^2(x) = var(x) + avg^2(x)$$

Suppose that we have the aggregated generation $G = G(t)$ observed over period *T*. Let a particular resource production for the same period is $g_j = g_j(t)$. The rest of generators in the analyzed aggregate produce

$$G_j^{'} = G_j^{'}(t) = G(t) - g_i(t)$$

The RMS aggregate generation is

$$\begin{aligned} rms^2 G &= avg\left(G_j^{'} + g_j\right)^2 = rms^2 G_j^{'} + rms^2 g_j + 2 \cdot avg\left(G_j^{'} \cdot g_j\right) \\ &= rms^2 G_j^{'} - rms^2 g_j + 2 \cdot avg\left(G \cdot g_j\right) \end{aligned}$$

We assume that the relative contribution γ_j of the *j*th resource to $rms^2 G$ can be expressed as follows:

$$\boxed{\gamma_j = \frac{avg\left(G \cdot g_j\right)}{rms^2(G)}}$$

This choice is supported by the following arguments.

First, it is easy to see that

$$avg\left(G \cdot g_j\right) = \frac{1}{4}\left[rms^2\left(G + g_j\right) - rms^2\left(G - g_j\right)\right]$$

that is the average $avg\left(G \cdot g_j\right)$ is proportional to the incremental impact that g_j poses on $rms^2 G$.

Second, because

$$\sum_j avg\left(G \cdot g_j\right) = avg\left(G \cdot \sum_j g_j\right) = avg\left(G^2\right) = rms^2 G$$

the sum of relative contributions γ_j for all resources in the aggregate to $rms^2 G$ is

$$\sum_j \gamma_j = 1$$

which is an absolutely necessary condition for any "fair share" convention (the sum of relative contributions of all resources in an aggregate must be equal to 1).

Now, the proposed "fair share" factor can be directly applied to estimate the share of any particular resource $M_j^{\pm}$ in the analyzed aggregate metric $M^{\pm}$. Here we assume that the individual resource scheduling and real-time dispatch errors e_j are statistically similar to $\gamma_j \cdot e$:

$$e_j : \gamma_j \cdot e$$

Therefore,

$$\begin{aligned} \Delta M_j^{\pm} &= avg_T\left[\gamma_j \cdot \left(e_2 - e_1\right)\right] \pm \eta \cdot \left[\sigma_T\left(\gamma_j \cdot e_2\right) - \sigma_T\left(\gamma_j \cdot e_1\right)\right] \\ &= \gamma_j \cdot \Delta M^{\pm} \end{aligned}$$

For the additional supplemental energy and regulation reserve requirements metrics, we have obtained the following simple expressions:

$$\boxed{\begin{aligned}\Delta M^{\pm}_{SUP,j} &= \gamma_j \cdot \Delta M^{\pm}_{SUP} \\ \Delta M^{\pm}_{REG,j} &= \gamma_j \cdot \Delta M^{\pm}_{REG}\end{aligned}}$$

3.7 Ancillary Services Method 2 References

[1] California ISO Amendment 42 Docket No. ER02-922-000 (Intermittent Resources; CT 487; Intra-zonal Congestion; and Real Time Pricing), 2002 – available at http://www.caiso.com/docs/2002/02/01/200202011116576547.html and http://www.caiso.com/docs/2003/01/29/2003012914271718285.html

[2] Y. V. Makarov, D. L. Hawkins, E. Leuze, and J. Vidov, " California ISO Wind Generation Forecasting Service Design And Experience ", Proc. of the 2002 AWEA Windpower Conference, Portland, Oregon, June 2-5, 2002.

4 Capacity Credit Analysis

MICHAEL MILLIGAN, NATIONAL RENEWABLE ENERGY LABORATORY

The methodology presented in this section was developed by Michael Milligan of NREL.

The standard techniques used to evaluate the reliability of power systems and how these techniques are used to measure planning capacity credit are based on Billinton & Allan (1984). Conventional power plants experience unplanned outages, either because of mechanical or other malfunction. Episodes such as this are called forced outages. It is unlikely that conventional generators will experience a forced outage because of fuel shortages. During extended periods of anticipated low loads, generating units can be taken offline for routine maintenance. There is always a non-zero probability that any single generating unit will be on forced outage. Taking all such probabilities from each generator allows us to calculate the probability that enough generator units are on forced outage that the utility will be unable to meet its load. This probability is the loss-of-load probability (LOLP).

The primary advantage of a reliability-based assessment of capacity value is that it quantifies the risk of not supplying enough generation to meet loads. Because there is a non-zero probability that any generator can fail at any time, reliability-based methods can be applied to any type of generator. Most conventional generators have relatively low failure rates, although these rates can vary according to unit size, age, fuel type, and other factors. Intermittent renewable generators typically have low mechanical failure rates, but are not able to generate power when the resource isn't available. This intermittency must be brought in to the reliability calculation, and the standard methods for calculating reliability can be modified to do this.

4.1 Effective Load Carrying Capability

Using the concepts and techniques from reliability theory, we want to provide a measure of generating plant capacity credit that can be applied to a wide variety of generators, not just renewables. Although no generator has a perfect reliability index, we can use such a concept as a benchmark to measure real generators. For example, a 500-MW generator that is perfectly reliable has an ELCC of 500 MW. If we introduce a 500-MW generator with a reliability factor of 0.85, or equivalently, a forced outage rate of 0.15, the ELCC of this generator <u>might</u> be 390 MW; however, the ELCC value cannot be calculated by simply multiplying the reliability factor by the rated plant output.

In general, the ELCC must be calculated by considering hourly loads and hourly generating capabilities. This procedure can be carried out with an appropriate production-simulation or reliability model. The electricity production simulation model calculates the expected loss of load. The usual formulation is based on the hourly estimates of LOLP, and the LOLE is the sum of these probabilities, converted to the appropriate time scale. The annual LOLE can be calculated as:

$$LOLE = \sum_{i=1}^{N} P(C_i < L_i) \qquad [4.1]$$

where *P()* denotes the probability function, *N* is the number of hours in the year, C_i represents the available capacity in hour *i*, and L_i is the hourly utility load. To calculate the additional reliability that results from adding intermittent generators, we can write *LOLE'* for the *LOLE* after renewable capacity is added to the system as:

$$LOLE' = \sum_{i=1}^{N} P[(C_i + g_i) < L_i] \qquad [4.2]$$

where g_i is the power output from the generator of interest during hour *i*. The ELCC of the generator is the additional system load that can be supplied at a specified level of risk (loss of load probability or loss of load expectation).

$$\sum_{i=1}^{N} P(C_i < L_i) = \sum_{i=1}^{N} P[(C_i + g_i) < (L_i + \Delta C_i)] \qquad [4.3]$$

Calculating the ELCC of the renewable plant amounts to finding the values ΔC_i that satisfy equation 4.3. This equation says that the increase in capacity that results from adding a new generator can support ΔC_i more MW of load at the same reliability level as the original load could be supplied (with C_i MW of capacity). To determine the annual ELCC, we simply find the value ΔC_p, where *p* is the hour of the year in which the system peak occurs after obtaining the values for ΔC_i that satisfy the equation. Because LOLE is an increasing function of load, given a constant capacity, we can see from Equation 4.3 that increasing values of ΔC_i are associated with declining values of *LOLE*. Unfortunately, it is not possible to analytically solve Equation 4.3 for ΔC_p. The solution for ΔC_p involves running the model for various test values of ΔC_p until the equality in Equation 4.3 is achieved to the desired accuracy.

Although the level of detail of the input data varies between models, hourly electric loads and generator data is required to calculate LOLE. Common outputs from these models include various costs and reliability measures, although cost data are not used to perform system reliability calculations. Some of the models used for these calculations are chronological, and others group related hours to calculate a probability distribution that describes the load level.

4.2 Simplified Capacity Credit Calculation Methods

This discussion has focused so far on standard approaches of measuring power plant capacity credit. Although reliability models provide the most accurate result, they require significant modeling effort. Various ad hoc methods for calculating wind plant capacity credit have been proposed, many of them using the capacity factor over some relevant time period. Related approaches, like those described by Wan (1997), use the median value of the wind plant over a recent history during the utility peak period. Other approaches have been suggested for situations where the appropriate modeling tools aren't available. These methods provide reasonable approximations to reliability-based methods.

Milligan & Parsons (1997 and 1999) compared a full complement of ELCC calculations to various capacity factor calculations. The results of these studies provide a benchmark of how well various capacity-factor measures can approximate the ELCC, as calculated by a reliability model. The first of the two simplified methods (NREL method 1) ranked all loads by LOLP (calculated using system data without intermittent generation), and then selected the top 10% of these loads. For the time periods represented by these loads, the intermittent generator capacity factor was calculated, and provided a reasonable approximation of the ELCC. The second method (NREL method 2) replaced the LOLP ranking with a ranking based only on the magnitude of the load. This second approach is somewhat easier and does not require the use of a reliability model, but is not quite as accurate as the LOLP ranking method.

Although this work focused on wind power plants, these techniques would be equally applicable to other intermittent technologies and the conclusions remain relevant. First, although capacity factor might be useful as an approximation to capacity credit, it appears to consistently *underestimate* the ELCC value. Second, the accuracy of capacity factor methods is sensitive to both the number of hours used and the method used to select the hours. Third, intermittent plants contribute to overall system reliability during non-peak hours.

Ad hoc methods that calculate the renewable plant capacity factor over a very small number of hours surrounding the peak may not adequately capture any impacts on system reliability. For example, a wind plant that produces at its rated capacity during a very small number of hours surrounding the peak would be rated with a capacity value at or near its rated capacity. However, such a plant would not provide the same level of capability during other near-peak hours as a conventional plant could potentially provide. Conversely, a wind plant that is given a capacity value of 0 might contribute significant levels of output during near-peak hours when system reliability is still critical.

4.3 Capacity Analysis Approach

It is important to be as precise as possible when calculating capacity value. Underestimating capacity value would put the system in a more reliable state than necessary (reliability is costly), and overestimating capacity value could put the system at increasing risk of outage. Power plants that increase system reliability should be recognized (and perhaps compensated) for their contribution. Unreliable plants should have lower capacity value, whereas reliable plants should have higher capacity value. Intermittent power generators that consistently deliver power during off-peak periods may not contribute significantly to system reliability and should therefore have a lower capacity value than a plant that can deliver power during peak periods.

ELCC calculations take all of this into account, quantifying the contributions of all generators based on actual data. In addition, ELCC calculations can quantify the probability that the intermittent generator forecasts overstate actual generation if forecast error data is available. Many utilities establish target reliability levels, such as the ubiquitous loss of load expectation of 1 day in 10 years. The ELCC calculation tells us the incremental load that can be supported by a new generator, bringing the system to its preferred risk level of 1 day in 10 years (or whatever reliability target is preferred by the utility, operating agent, or regulatory body). Conventional generators with low forced outage rates typically have an ELCC that is "close" to rated capacity. Intermittent renewable power plants increase system reliability, but do so at a fraction of their rated capacity, depending on the timing and quantity of output.

The proposed capacity analysis approach can be outlined as follows:

1. Run a system reliability model with the renewable generators to determine the existing reliability level, using either LOLE or EUE.

2. Remove the renewable generator from the system and rerun the model to determine the incremental reliability that is provided by the renewable generator.

3. Return to the configuration of step 1. Incrementally decrease hourly loads and rerun the model until the reliability of the system matches that in step 2.

4. The reduction in system load in step 3 is the ELCC of the existing renewable generator.

For purposes of this study we expect to apply the ELCC method, followed by NREL method 1 and 2 so that we can establish the relationship between the ELCC calculation results and the approximate methods. It is anticipated that one of the alternative methods will be selected for use in calculating the capacity value of a renewable generator in the RPS bid selection process so that the unique characteristics of California loads and wind generation are properly accounted for.

4.4 Data Requirements

1. If ELCC is calculated:

   - Total load for each hour of the year
   - Total hourly generation from each renewable generator of interest
   - Forecast option: Hourly actual and forecast renewable energy generation
   - Monthly (or annual) generator capacity and forced outage rates
   - Net actual imports/exports

2. If NREL method 1 is used:

   - Total load for each hour of the year
   - Hourly LOLP of EUE calculated by excluding renewable generation
   - Total hourly generation from each renewable generator of interest

3. If NREL method 2 is used:

- Total load for each hour of the year
- Total hourly generation from each renewable generator of interest

Table 4.1 ELCC Capacity Valuation Analysis Input Data

1. system load (MWh) [hourly for 8760 hours]

2. hourly production (MWh) for all plants [hourly for 8760 hours]
    a. biomass
    b. geothermal
    c. small hydro
    d. solar photovoltaic
    e. solar thermal
    f. wind

3. for all conventional generators >50 MW
    a. generator capacity
    b. forced outage rates
    c. maintenance outage rates
    d. waiver outage rates (off-line for market reasons)

4. for all conventional generators <50 MW
    a. aggregated generator capacity
    b. forced outage rates
    c. maintenance outage rates waiver outage rates (off-line for market reasons)

4.5 Capacity Credit References

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